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Analyst Reports

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- Williams Companies

SEC Filings

Boardwalk Pipelines, LP
- 10Q Filed for Period Ending September 30, 2008
- 10K Filed for Period Ending December 31, 2007

Enbridge Energy Partners, LP
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- 10K Filed for Period Ending December 31, 2007

Enterprise Products Partners, LP
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- 10K Filed for Period Ending December 31, 2007

Kinder Morgan Energy Partners, LP
- 10Q Filed for Period Ending September 30, 2008
- 10K Filed for Period Ending December 31, 2007

National Fuel Gas Company
- 10Q Filed for Period Ending June 30, 2008
- 10K Filed for Period Ending September 30, 2007

ONEOK Partners, LP
- 10Q Filed for Period Ending September 30, 2008
- 10K Filed for Period Ending December 31, 2007

Spectra Energy Corporation
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Williams Companies
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STANDARD & POOR'S

Quantitative Stock Report
Feb 14,2009
NYSE SYMBOL:**BWP**

Boardwalk Pipeline Ptnrs LP

S&P Quality Ranking: **NR** Standard & Poor's Fair Value Rank : **NR**

Sector: Energy
Sub-Industry: Oil & Gas Storage & Transportation

Summary: This limited partnership engages in the interstate transportation and storage of natural gas.

Quantitative Evaluations

S&P Quality Ranking : NR

S&P Fair Value Rank: NR

Fair Value Calc: NA

S&P Investability Quotient Percentile

92%

1 Lowest — Highest 100

BWP scored higher than 92% of all companies for which an S&P Report is available.

Volatility: Average

Low | **Average** | High

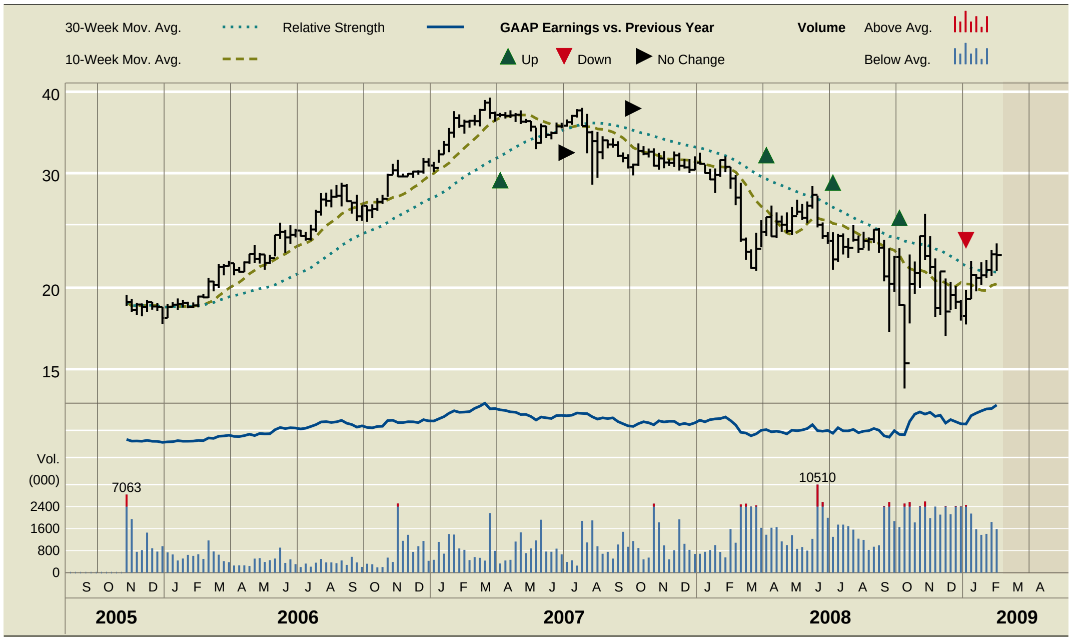
Technical Evaluation: BULLISH
Since January, 2009, the technical indicators for BWP have been BULLISH.

Relative Strength Rank: Strong

85

1 Lowest — Highest 99

Price as of Feb 13,2009: $22.44 | **52-Week Range: $29.80 - $14.00**



Options: Ph

Investment Strategy

Key financial variables to consider in assessing the investment merits of an industrial company are the following:

Sales: What is the trend? Is future sales growth expected to be greater than the past 5-year and 9-year growth average? Accelerating sales growth ultimately provides the fuel behind earnings growth.

Net Margin: As a key measure of company profitabilty, a rising net margin assesses management capability to wring out more net income from incremental sales.

% LT Debt to Capitalization: A rising percentage implies greater financial risk, all else being equal. Rising debt leverage without a concomitant rise in Return on Equity should raise warning signals of potential cash flow problems. Percentages above 40%-50% should also be considered a warning.

% Return on Equity: A key perfomance measurement of capital efficiency assesses what investment returns management can earn on a company's existing capital base. A sustained percentage above 20% is considered above average.

Revenues/Earnings Data Fiscal year ending Dec. 31

Revenues (Million $)

	2008	2007	2006	2005	2004	2003
1Q	197.3	188.1	174.5	--	--	--
2Q	190.3	150.5	128.7	--	--	--
3Q	191.6	134.7	133.0	--	--	--
4Q	205.6	169.9	--	--	--	--
Year	784.8	643.3	607.6	560.5	504.4	--

Earnings per Share ($)

	2008	2007	2006	2005	2004	2003
1Q	0.69	0.61	0.58	--	--	--
2Q	0.49	0.35	0.35	--	--	--
3Q	0.47	0.35	0.35	--	--	--
4Q	0.39	0.55	--	--	--	--
Year	1.77	1.87	1.32	0.35	1.15	--

Next earnings report expected: Late April

Historical GAAP earnings are as reported.

Key Growth Rates and Averages

Past Growth Rate (%)	1 Year	3 Year	5 Year	9 Year
Sales	5.86	8.44	22.48	NA
Net Income	15.29	29.92	35.27	NA
Ratio Analysis (Average)				
Net Margin	35.41	28.64	26.35	NA
%LT Debt to Capitalization	50.61	51.60	NA	NA
% Return on Equity	14.81	14.03	14.59	NA

Key Stock Statistics

Average Daily Volume	**0.322 mil.**	Beta	**0.06**
Market Capitalization	**$3.514 Bil.**	Trailing 12 Month EPS	**$1.77**
Institutional Holdings (%)	**51**	12 Month P/E	**12.7**
Shareholders of Record	**39**	Current Yield (%)	**8.56**

Value of $10,000 Invested five yrs Ago : **NA**

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STANDARD & POOR'S

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Feb 14,2009
NYSE SYMBOL:**BWP**

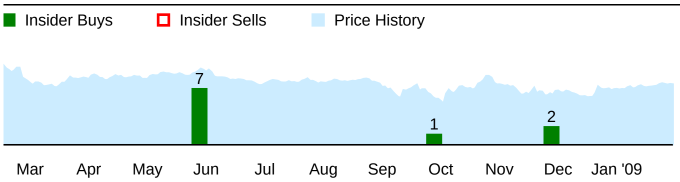
Boardwalk Pipeline Ptnrs LP

S&P Quality Ranking: **NR** Standard & Poor's Fair Value Rank : **NR**

Wall Street Opinions/Average (Mean) Opinion: Hold

	No. of Ratings	% of Total	1 Mo. Prior	3 Mo. Prior
Buy	3	25	3	3
Buy/Hold	2	17	2	2
Hold	5	42	5	5
Weak Hold	2	17	2	2
Sell	0	0	0	0
No Opinion	0	0	0	0
Total	12	100	12	12

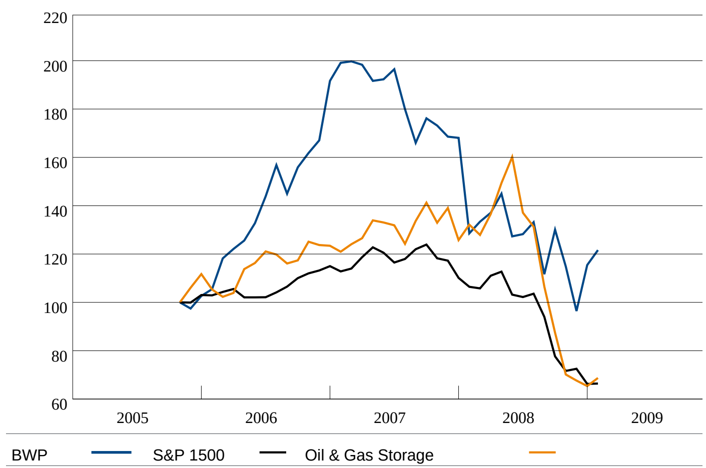
Insider Moves



Dividend Data
Dividend have been paid since 2006

Amount($)	Date Decl.	Ex. Div. Date	Stock of Record	Payment Date
0.465	Apr.24	May.1	May.5	May.12 '08
0.470	Jul.24	Jul.31	Aug.4	Aug.11 '08
0.475	Oct.22	Oct.30	Nov.3	Nov.10 '08
0.480	Feb.5	Feb.11	Feb.16	Feb.23 '09

Stock Performance



	Company(%)	Industry(%)	S&P 1500(%)
YTD Return	28.9	1.6	-8.4
One Year Return	-16.0	-47.5	-39.3
Three Year Return (% Annualized)	13.1	-12.8	-13.2
Five Year Return (% Annualized)	--	--	-6.0
Value of $10,000 Invested 5 Years Ago	NA	--	$7,351

Company Financials
Fiscal year ending Dec. 31

Per Share Data & Valuation Ratios ($)	2008	2007	2006	2005	2004	2003	2002	2001	2000	1999
Tangible Book Value	NA	13.25	10.25	7.98	NA	NA	NA	NA	NA	NA
Cash Flow	NA	2.68	2.52	1.67	NA	NA	NA	NA	NA	NA
Earnings	1.77	1.87	1.32	1.00	1.15	NA	NA	NA	NA	NA
Dividends	NA	1.74	1.32	NA	NA	NA	NA	NA	NA	NA
Payout Ratio	NA	93%	71%	NA	NA	NA	NA	NA	NA	NA
Prices:High	NA	39.20	31.64	NA	NA	NA	NA	NA	NA	NA
Prices:Low	NA	28.80	17.98	NA	NA	NA	NA	NA	NA	NA
P/E Ratio:High	NA	21	17	NA	NA	NA	NA	NA	NA	NA
P/E Ratio:Low	NA	15	10	NA	NA	NA	NA	NA	NA	NA
Income Statement Analysis (Million $)										
Revenue	785	643	608	560	504	256	267	NA	NA	NA
Operating Income	NA	376	333	280	NA	NA	NA	NA	NA	NA
Depreciation	NA	81.8	75.8	72.1	NA	36.6	37.8	NA	NA	NA
Interest Expense	57.7	88.1	62.1	58.6	63.2	26.8	20.5	NA	NA	NA
Pretax Income	295	229	198	161	119	94.4	92.8	NA	NA	NA
Effective Tax Rate	0.34%	0.34%	0.13%	37%	NA	40%	40%	NA	NA	NA
Net Income	294	228	198	101	119	56.9	56.1	NA	NA	NA
Balance Sheet & Other Financial Data (Million $)										
Cash	NA	317	399	65.8	28.4	19.2	NA	NA	NA	NA
Current Assets	NA	456	548	206	NA	NA	NA	NA	NA	NA
Total Assets	NA	4,157	2,951	2,465	2,365	1,239	NA	NA	NA	NA
Current Liabilities	NA	389	228	202	NA	NA	NA	NA	NA	NA
Long Term Debt	NA	1,848	1,351	1,101	NA	NA	NA	NA	NA	NA
Common Equity	NA	1,803	1,273	989	937	523	NA	NA	NA	NA
Total Capital	NA	3,651	2,623	2,090	NA	NA	NA	NA	NA	NA
Capital Expenditures	NA	1,210	200	83.0	NA	34.8	27.5	NA	NA	NA
Cash Flow	NA	310	273	173	NA	NA	NA	NA	NA	NA
Current Ratio	NA	1.2	2.4	1.0	0.9	0.9	NA	NA	NA	NA
% Long Term Debt of Capitalization	Nil	50.6	51.5	52.7	55.1	49.5	Nil	NA	NA	NA
% Net Income of Revenue	37.5	35.4	32.5	18.0	23.6	22.2	21.0	NA	NA	NA
% Return on Assets	NA	6.4	7.3	4.1	NA	NA	NA	NA	NA	NA
% Return on Equity	NA	14.8	17.5	9.8	16.3	NA	NA	NA	NA	NA

Data as orig. reptd; bef. results of disc opers/spec. items. Per share data adj. for stk. divs. as of ex-div date. NA-Not Available. NM-Not Meaningful. NR-Not Ranked.

Office: **3800 Frederica Street, Owensboro, KY, 42301**
Tel: **270-926-8686**
Website: **http://www.boardwalkpipelines.com**
Chrmn: **A. L. Rebell**
Pres & CEO: **R. Gafvert**

Dirs: **W. R. Cordes, R. Gafvert, T. E. Hyland, J. E. Nathanson, A. L. Rebell, M. L. Shapiro, A. Tisch**
SVP & CFO: **J. L. Buskill**
Secy, SVP & General Counsel: **M. E. McMahon**

Chief Acctg Officer & Cntlr: **S. A. Barkauskas**
Investor Contact: **Petra TAbor(866-913-2122)**
Founded: **2005**
Domicile: **Delaware**
Employees: **1,084**

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STANDARD
&POOR'S

Quantitative Stock Report
Feb 14,2009
NYSE SYMBOL:**BWP**

Boardwalk Pipeline Ptnrs LP

S&P Quality Ranking: **NR**   Standard & Poor's Fair Value Rank : **NR**

Sub-Industry Outlook

Our fundamental outlook for the oil and gas storage and transportation sub-industry for the next 12 months is neutral. We expect fee-based pipeline and terminal operators to continue to expand earnings well in excess of anticipated real U.S. GDP growth in 2008 and 2009. As of January, S&P estimated a 1.1% increase in U.S. real GDP for 2008 and a 2.0% decline for 2009, compared to the 2.0% rise in 2007. However, we believe that investors are concerned that the tightening credit market may hinder MLPs from raising capital to fund their expansion projects. In response to the poor credit environment and weak economy, many MLPs plan to reduce their capital expansion budgets for 2009 to preserve capital and maintain their dividends.

We believe that 2009 will be a volatile year for tanker companies. Based on industry research group Bassoe, daily spot charter rates for VLCCs were $66,000 in the fourth quarter of 2008, below the $91,000 average in the third quarter. We expect tanker rates to continue to soften in 2009, due to the expected increase in the worldwide fleet, cuts in OPEC production, and the slowing global economy. The shipping industry suffered from increased piracy in 2008. If piracy is not curtailed, many shippers will re-route their vessels, leading to longer and more expensive trips, in our opinion.

As of early January 2009, the Energy Information Administration (EIA) estimated that U.S. petroleum consumption declined 5.7% in 2008 and would fall another 2.0% in 2009, after being little changed in 2007. The EIA also estimated that natural gas consumption would increase 0.7% in 2008 and decline 1.0% in 2009. Longer term, we think drivers for new transportation infrastructure include new import terminals for liquefied natural gas, transcontinental movement of gas from the Rockies to Northeast markets, and increased oil sands production in Alberta. In our view, an active merger and acquisition environment will also remain a principal investor focus. Current yields as of February 3, 2009, on our universe of MLPs averaged about 11.0%, above the benchmark 10-year Treasury note, which was yielding about 2.83% at that time.

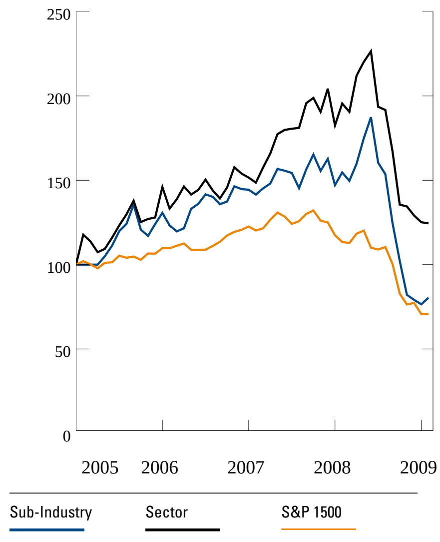
Year to date through February 2, the S&P Oil and Gas Storage and Transportation Index rose 1.1%, versus a 8.6% decline for the S&P 1500. In 2008, the S&P Oil and Gas Storage and Transportation Index was down 10.5%, versus a 38.2% decline for the S&P 1500. Our preference is for those issues with the potential to increase cash flow and dividend payouts over time.

--T. Shafi

Stock Performance

GICS Sector: **Energy**
Sub-Industry: **Oil & Gas Storage & Transportation**

Based on S&P 1500 Indexes
Month-end Price Performance as of 01/30/09



NOTE: All Sector & Sub-Industry information is based on the Global Industry Classification Standard (GICS)

Sub-Industry : Oil & Gas Storage & Transportation Peer Group*: Based on market capitalizations within GICS Sub-Industry

Peer Group	Stock Symbol	Stk.Mkt. Cap. (Mil. $)	Recent Stock Price($)	52 Week High/Low($)	Beta	Yield (%)	P/E Ratio	Fair Value Calc.($)	Quality Ranking	S&P IQ %ile	Return on Revenue (%)	LTD to Cap (%)
Boardwalk Pipeline Ptnrs LP	**BWP**	**3,514**	**22.44**	**29.80/14.00**	**0.06**	**8.6**	**13**	**NA**	**NR**	**92**	**37.5**	**NA**
Buckeye GP Hldg L.P.	BGH	447	15.80	28.50/9.51	0.19	8.4	17	NA	NR	54	1.4	39.8
Cheniere Energy Ptnrs L.P.	CQP	1,010	6.24	17.57/3.65	NA	27.2	NM	NA	NR	52	NM	NA
Eagle Rock Energy Ptnrs L.P.	EROC	508	7.02	17.96/4.00	0.15	23.4	NM	NA	NR	66	NM	43.8
El Paso Pipeline Ptnrs L.P.	EPB	2,049	18.18	24.35/11.72	NA	6.3	23	NA	NR	38	60.0	53.8
Energy Transfer Equity L.P.	ETE	4,361	19.57	35.02/12.75	0.79	10.4	13	NA	NR	30	4.7	NA
Enterprise GP Holdings L.P.	EPE	2,801	22.74	33.76/14.50	0.38	8.3	17	NA	NR	85	0.4	51.0
Genesis Energy L.P.	GEL	479	12.15	22.33/6.42	1.57	10.9	NM	NA	NR	72	NM	10.9
Inergy Holding LP	NRGP	617	30.50	46.97/14.35	0.36	8.9	16	NA	NR	23	1.9	91.7
Kayne Anderson MLP Inv	KYN	820	19.50	31.45/11.07	0.91	10.3	NM	NA	NR	44	NA	NA
NuStar GP Hldgs LLC	NSH	839	19.73	28.41/12.16	0.48	8.7	13	NA	NR	78	NM	NA
Regency Energy Ptnrs LP	RGNC	912	11.23	31.18/4.92	0.98	15.9	13	10.60	NR	33	NM	50.3
Southern Union	SUG	1,710	13.79	28.62/10.60	1.28	4.4	8	15.20	B	72	8.7	50.5
Williams Partners L.P.	WPZ	909	17.23	38.00/9.96	0.81	14.7	6	NA	NR	50	28.7	86.1
Williams Pipeline Ptnrs L.P.	WMZ	547	16.31	20.04/10.55	NA	7.8	4	NA	NR	74	NA	NA

NA-Not Available NM-Not Meaningful NR-Not Rated. *For Peer Groups with more than 15 companies or stocks, selection of issues is based on market capitalization.

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S&P Analyst Research Notes and other Company News

October 28, 2008
Boardwalk Pipeline Partners, LP announced earnings results for the third quarter and nine months ended September 30, 2008. For the third quarter the company reported net income of $73.6 million an 84% increase from $40.0 million in the comparable period of 2007. Operating revenues of $191.6 million a 42% increase from $134.8 million in the comparable 2007 period. Earnings before interest, taxes, depreciation and amortization of $116.1 million a 67% increase from $69.6 million in the comparable 2007 period. Operating profit was $89 million when compared to $48.6 million for the same period last year. Net income less general partner's interest was $70.1 million or $0.47 per share when compared to net income of $38.5 or $0.35 per share million for the same period last year. For the nine months the company reported net income of $226.4 million, an 46% increase from $155.6 million in the comparable 2007 period. Operating revenues of $579.2 million a 22% increase from $473.4 million in the comparable 2007 period. Earnings before interest, taxes, depreciation and amortization of $362.5 million a 47% increase from $246.5 million in the comparable 2007 period. Operating profit was $271.3 million when compared to $185.2 million for the same period last year. Net income less general partner's interest was $216.7 million or $1.58 per share when compared to net income of $151.1 or $1.32 per share million for the same period last year.

June 4, 2008
02:50 pm ET ... S&P REDUCES RECOMMENDATION ON SHARES OF LOEWS CORP TO HOLD FROM BUY (LTR 50.5***): Our downgrade is based on valuation following a sizable recent increase in the share price. We believe LTR will continue to benefit from 50.5%-owned Diamond Offshore (DO 131.19***) and 70%-owned Boardwalk Pipeline Partners (BWP 27.82, NR). However, we are concerned that the slowing economy may hinder revenue growth in its hotel operations. We are maintaining our '08 EPS forecast from continuing operations of $4.83, but we are increasing our 12-month target price to $54 from $50, 11.2X that estimate and in line with its historical multiples. /T.Shafi

May 12, 2008
On May 8, 2008, Boardwalk Pipeline Partners, LP and John C. Earley entered into a Separation Agreement and General Release in conjunction with Mr. Earley's resignation as Senior Vice President of Operations.

April 29, 2008
Boardwalk Pipeline Partners, LP reported earnings results for the first quarter ended March 31, 2008. For the quarter, the company reported net income of $88.1 million or basic and diluted earnings of $0.60 per limited partner unit against net income of $80.2 million or basic and diluted earnings of $0.61 per limited partner unit for the same period in 2007. Total operating revenues were $197.3 million against $188.1 million for the same period in 2007. The company reported asset impairment of $1.4 million in the first quarter ended March 31, 2008.

February 12, 2008
Boardwalk Pipeline Partners LP announced earnings results for the fourth quarter and year ended December 31, 2007. For the quarter, the company reported net income of $72,095,000 or $0.54 basic and diluted net income per limited partner unit on total operating revenues of $169,883,000 against net income of $65,272,000 or $0.55 basic and diluted net income per limited partner unit on total operating revenues of $171,489,000 for the same period a year ago. For the full year, the company reported net income of $227,756,000 or $1.87 basic and diluted net income per limited partner unit on total operating revenues of $643,268,000 against net income of $197,550,000 or $1.85 basic and diluted net income per limited partner unit on total operating revenues of $607,642,000 for the same period a year ago.

December 20, 2007
Boardwalk Pipeline Partners, LP announced several changes as part of the organizational realignment that was begun early this year, including the consolidation of senior management in Houston and certain operational functions in Owensboro, Ky. President H. Dean Jones II announced his retirement effective March 1, 2008. In order to have Boardwalk's senior management team in the same location, three officers will be moving from Owensboro to Houston. They are Jamie Buskill, Senior Vice President, Treasurer and Chief Financial Officer; Steven Barkauskas, Vice President, Controller and Chief Accounting Officer; and James Jones, Vice President of Tax.

October 30, 2007
Boardwalk Pipeline Partners LP announced earnings results for the third quarter ended September 30, 2007. For the quarter, the company reported net income of $40.0 million or $0.35 per share on total operating revenues of $134.7 million against net income of $30.6 million or $0.35 per share on total operating revenues of $133.0 million, reported for the same period a year ago. For the nine months, the company reported net income of $155.6 million or $1.32 per share on total operating revenues of $473.4 million against net income of $132.2 million or $1.27 per share on total operating revenues of $436.1 million, reported for the same period a year ago.

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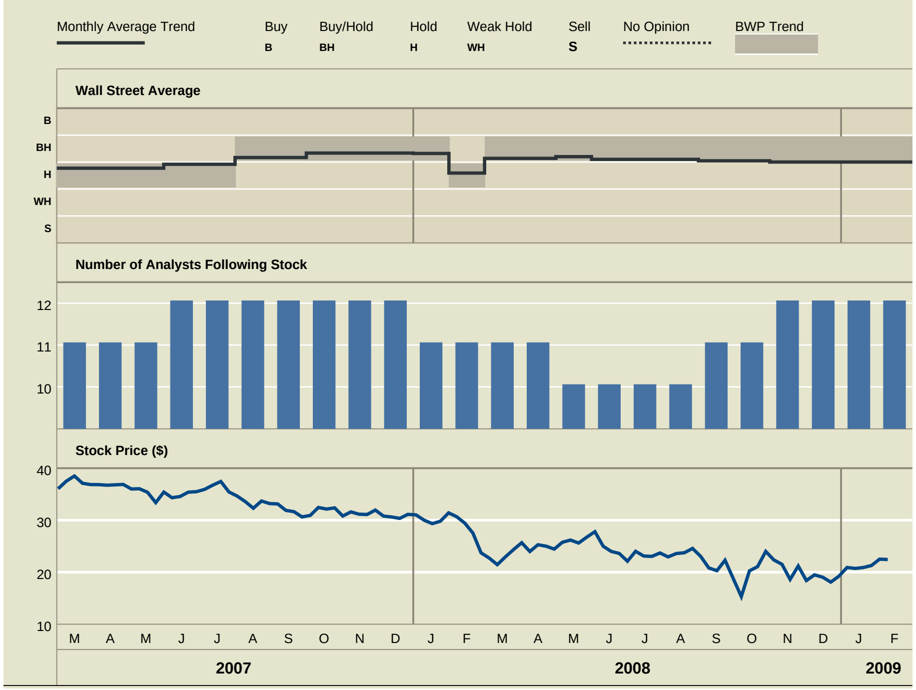
S&P Quality Ranking: **NR** Standard & Poor's Fair Value Rank : **NR**

Analysts' Recommendations



Of the total 12 companies following BWP, 12 analysts currently publish recommendations.

	No. of Ratings	% of Total	1 Mo. Prior	3 Mos. Prior
Buy	3	25	3	3
Buy/Hold	2	17	2	2
Hold	5	42	5	5
Weak Hold	2	17	2	2
Sell	0	0	0	0
No Opinion	0	0	0	0
Total	**12**	**100**	**12**	**12**

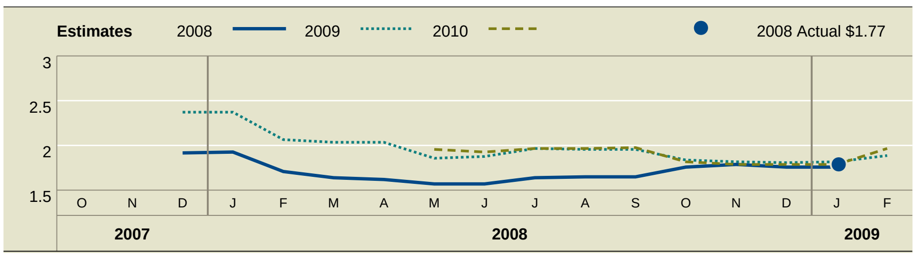
Wall Steet Consensus Opinion

BUY/HOLD

Companies Offering Coverage

Argus Research Corp.
Barclays Capital
Deutsche Bank
Merrill Lynch Research
Morgan Stanley & Company
Morgan, Keegan & Company, Inc.
Pickering Energy Partners, Inc.
RBC Capital Markets (US)
Raymond James & Assoc, Inc.
Smith Barney
UBS Warburg
Wachovia Securities

Wall Street Consensus Estimates



Fiscal Years	Avg Est.	High Est.	Low Est.	# of Est.	Est. P/E
2010	1.97	2.49	1.65	9	11.4
2009	1.89	2.86	1.55	12	11.9
2010 vs. 2009	▲ 4%	▼ -13%	▲ 6%	▼ -25%	▼ -4%
Q1'10	0.56	0.65	0.51	3	40.1
Q1'09	0.51	0.77	0.38	9	44.0
Q1'10 vs. Q1'09	▲ 10%	▼ -16%	▲ 34%	▼ -67%	▼ -9%

A company's earnings outlook plays a major part in any investment decision. Standard & Poor's organizes the earnings estimates of over 2,300 Wall Street analysts, and provides their consensus of earnings over the next two years. This graph shows the trend in analyst estimates over the past 15 months.

Wall Street Consensus vs. Performance

For fiscal year 2009, analysts estimate that BWP will earn $1.89. For fiscal year 2010, analysts estimate that BWP's earnings per share will grow by 4% to $1.97.

Source: S&P,I/B/E/S International, Inc.
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Boardwalk Pipeline Ptnrs LP

S&P Quality Ranking: **NR** Standard & Poor's Fair Value Rank : **NR**

Glossary

S&P Quality Ranking - Growth and stability of earnings and dividends are deemed key elements in establishing S&P's quality ranking for common stocks, which are designed to capsulize the nature of this record in a single symbol. It should be noted that, however, that the process also takes into consideration certain adjustments and modifications deemed desirable in establishing such rankings, The final score for each stock is measured against a scoring matrix determined by analysis of the scores of a large and representative sample of stocks. The range of scores in the array of this sample has been aligned with the following ladder of rankings:

A+	Highest	B	Lower
A	High	B-	Below Average
A-	Above Average	C	Lowest
B+	Average	D	In Reorganization
NR	Not Ranked		

S&P Fair Value Rank - Using S&P's exclusive proprietary quantitative model, stocks are ranked in one of five groups, ranging from Group 5, listing the most undervalued stocks, to Group 1, the most overvalued issues. Group 5 stocks are expected to generally outperform all others. A positive (+) or negative (-) Timing Index is placed next to the Fair Value ranking to further aid the selection process. A stock with a (+) added to the Fair Value Rank simply means that this stock has a somewhat better chance to outperform other stock with the same Fair Value Rank. A stock with a (-) has a somewhat lesser chance to outperform other stocks with the same Fair Value Rank. The Fair Value rankings imply the following: 5-Stock is significantly undervalued; Fair Value Rank. A stock with a (-) has a somewhat lesser chance to outperform other stocks with the same Fair Value Rank. The Fair Value rankings imply the following: 5-Stock is significantly undervalued; 4-Stock is moderately undervalued; 3-Stock is fairly valued; 2-Stock is modestly overvalued; 1-Stock is significantly overvalued.

Funds From Operations (FFO) - FFO is Funds from Operations and equal to a REIT's net income, excluding gains or losses from sales of property, plus real estate depreciation.

Fair Value Calculation - The current price at which a stock should sell today as calculated by S&P's computers using our quantitative model based on the company's earnings, growth potential, return on equity relative to the S&P 500 and its industry group, price to book ratio history, current yield relative to the S&P 500, and other factors.

Investability Quotient (IQ) - The IQ is a measure of investment desirability. It serves as an indicator of potential medium-to-long-term return and as a caution against downside risk. The measure takes into account variables such as technical indicators, earnings estimates, liquidity, financial ratios and selected S&P proprietary measures.

Standard & Poor's IQ Rationale:
Boardwalk Pipeline Ptnrs LP

	Raw Score	Max Value
Proprietary S&P Measures	25	115
Technical Indicators	29	40
Liquidity/Volatility Measures	14	20
Quantitative Measures	71	75
IQ Total	139	250

Volatility - Rates the volatility of the stock's price over the past year.

Technical Evaluation - In researching the past market history of prices and trading volume for each company, S&P's computer models apply special technical methods and formulas to identify and project price trends for the stock.

Relative Strength Rank - Shows, on a scale of 1 to 99, how the stock has performed versus all other companies in S&P's universe on a rolling 13-week basis.

Global Industry Classification Standard (GICS) - An industry classification standard, developed by Standard & Poor's in collaboration with Morgan Stanley Capital International (MSCI). GICS is currently comprised of 10 Sectors, 24 Industry Groups , 67 Industries, and 147 Sub-Industries.

Dividends on American Depository Receipts (ADRs) and American Depository Shares (ADSs) are net of taxes (paid in the country of origin).

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Stock Report | February 14, 2009 | NYS Symbol: **EEP**

STANDARD &POOR'S

Enbridge Energy Partners LP

S&P Recommendation HOLD ★★★★★

Price
$31.16 (as of Feb 13, 2009)

12-Mo. Target Price
$34.00

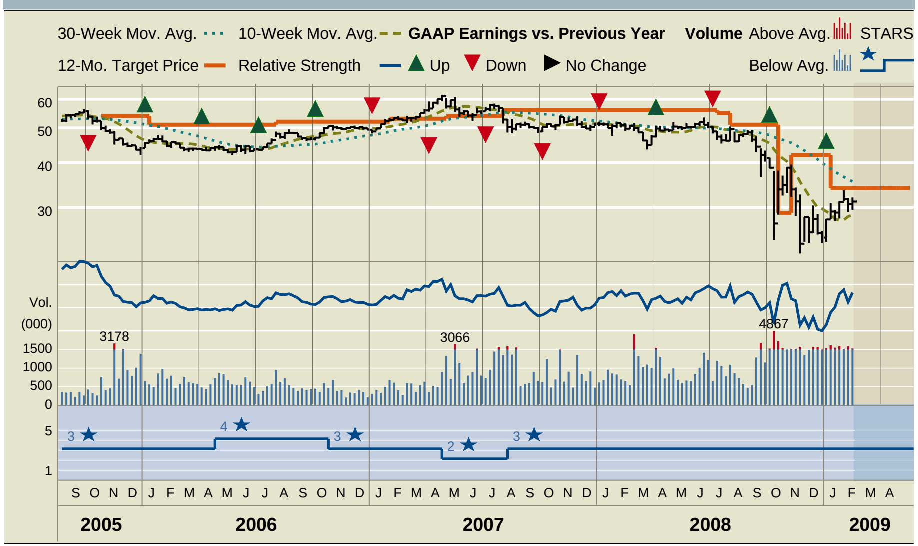
GICS Sector Energy
Sub-Industry Oil & Gas Storage & Transportation

Summary This limited partnership owns the U.S. portion of the world's longest crude oil pipeline; it acquired a natural gas transportation business in late 2001.

Key Stock Statistics (Source S&P, Vickers, company reports)

52-Wk Range	**$53.45– 22.33**	S&P Oper. EPS 2008**E**	**3.62**	Market Capitalization(B)	**$1.865**	Beta	**0.36**
Trailing 12-Month EPS	**$3.63**	S&P Oper. EPS 2009**E**	**2.95**	Yield (%)	**12.71**	S&P 3-Yr. Proj. EPS CAGR(%)	**3**
Trailing 12-Month P/E	**8.6**	P/E on S&P Oper. EPS 2008**E**	**8.6**	Dividend Rate/Share	**$3.96**	S&P Credit Rating	**BBB**
$10K Invested 5 Yrs Ago	**$9,331**	Common Shares Outstg. (M)	**97.3**	Institutional Ownership (%)	**33**		

Price Performance



Options: CBOE

Analysis prepared by **Tanjila Shafi** on February 04, 2009, when the stock traded at **$ 29.80**.

Highlights

➤ In 2009, we believe that operating income will be driven by EEP's expansion projects. The partnership plans to spend more than $2.2 billion on expansion projects between 2009 and 2010. The $635 million Clarity pipeline in the East Texas System will move increasing production of natural gas from the region and is scheduled for completion in the first quarter of 2009. This project is expected to generate $80-$100 million in EBITDA annually.

➤ With completion expected in early 2009, the $2.1 billion Southern Access Expansion is designed to deliver up to 400,000 bpd of heavy crude from Wisconsin to the Lakehead System in the Chicago area and to the Patoka Hub in southern Illinois and is expected to generate $240 million in EBITDA annually. The $1.2 billion Alberta Clipper Expansion is expected to deliver up to 800,000 bpd of heavy crude between Canada and Wisconsin beginning in mid-2010.

➤ EEP declared a fourth quarter 2008 distribution of $0.99, or $3.96 annualized, representing an increase of 4.2% from a year earlier. Our cash distribution estimate for 2009 is $3.96.

Investment Rationale/Risk

➤ We believe that the improving performance of the Lakehead pipeline system's volumes foreshadows a durable trend of increasing throughput from the oil sands production in Alberta, based on the new Southern Access Expansion project and the Alberta Clipper pipeline. EEP's natural gas transmission business is accessing some of the fastest growing domestic producing areas, including the Barnett Shale and Anadarko Basin in Texas. We believe the partnership's plans to invest significant capital in organic growth projects from 2008 through 2010 will limit EEP's ability to raise its cash distribution.

➤ Risks to our recommendation and target price include higher interest rates, and a decrease in economic activity that lowers demand for energy commodities and EEP's transportation volumes.

➤ Our 12-month target price of $34 is based on 11.6% target yield (in line with peers) on our one-year-out annualized distribution estimate of $3.96 per unit.

Qualitative Risk Assessment

LOW	**MEDIUM**	HIGH

Our risk assessment reflects that EEP and most MLPs in general are exposed to cyclical swings in demand for commodity transportation, potential conflicts of interest between MLP holders and the general partners, and a tendency toward excessive use of debt to fund dividend payments and capital expenditures. These risks are offset by the maturity of the business, and our view of EEP's exceptional revenue and cash flow visibility.

Quantitative Evaluations

S&P Quality Ranking **NR**

D	C	B-	B	B+	A-	A	A+

Relative Strength Rank **STRONG**

76

LOWEST = 1 HIGHEST = 99

Revenue/Earnings Data

Revenue (Million $)

	1Q	2Q	3Q	4Q	Year
2008	2,099	2,932	2,813	1,880	10,060
2007	1,713	1,739	1,171	2,120	7,283
2006	1,889	1,425	1,532	1,663	6,509
2005	1,250	1,333	1,810	2,085	6,477
2004	982.5	969.7	1,005	1,335	4,292
2003	896.1	755.3	760.5	760.0	3,172

Earnings Per Share ($)

2008	0.99	0.50	1.09	1.04	3.63
2007	0.40	0.69	0.75	0.23	2.08
2006	1.12	0.96	1.03	0.56	3.62
2005	0.37	0.32	-0.32	0.69	1.06
2004	0.50	0.56	0.39	0.61	2.06
2003	0.62	0.39	0.38	0.54	1.93

Fiscal year ended Dec. 31. Next earnings report expected: Late April. EPS Estimates based on S&P Operating Earnings; historical GAAP earnings are as reported.

Dividend Data (Dates: mm/dd Payment Date: mm/dd/yy)

Amount ($)	Date Decl.	Ex-Div. Date	Stk. of Record	Payment Date
0.950	04/28	05/05	05/07	05/15/08
0.990	07/28	08/04	08/06	08/14/08
0.990	10/13	11/04	11/06	11/14/08
0.990	01/30	02/03	02/05	02/13/09

Dividends have been paid since 1992. Source: Company reports.

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Enbridge Energy Partners LP

STANDARD &POOR'S

Business Summary February 04, 2009

CORPORATE OVERVIEW. Formed in 1991 by the general partner, Enbridge Energy Co., Inc., EEP owns and operates crude oil and liquid petroleum transportation assets and natural gas gathering, treating, processing, transmission and marketing assets in the U.S. Its principal asset is the Lakehead Pipeline System, which is the U.S. portion of a crude oil and liquid petroleum pipeline system extending from western Canada through the upper and lower Great Lakes region of the U.S. to eastern Canada.

Since May 2001, the partnership has diversified its operations both geographically and by industry. The North Dakota System, acquired in May 2001, connects to the partnership's Lakehead System and accessed a different crude oil supply basin in North Dakota and Montana. The East Texas System, acquired in November 2001, was the partnership's first entry into the natural gas gathering and processing business and diversified the geographic focus of the partnership to include the southern United States. In October 2002, the partnership continued its diversification through the acquisition of the Midcoast System, which included natural gas gathering, treating, processing, transmission and marketing activities located in the southern United States. On December 31, 2003, the partnership acquired the North Texas System, a natural gas gathering and processing business in Texas. In January 2005, additional North Texas assets were purchased from Devon Energy for $165 million. In June 2005, EEP completed the construction of a pipeline to connect its East Texas System to the Carthage, TX, hub. The new properties are allowing the partnership to achieve a larger scale and geographic profile from its East Texas System into the Texas Panhandle, where it can pursue commercial and operating synergies.

The partnership's $2.1 billion Southern Access Expansion, which will supply additional heavy crude oil capacity to the Lakehead system, is expected to add 190,000 bpd of capacity in 2008 and an additional 210,000 bpd of capacity by early 2009. The $1.2 billion Alberta Clipper pipeline project, between Alberta and Wisconsin, will increase capacity by 450,000 bpd in 2010. These projects result from the need for additional capacity based on forecasts of oil sands production growth.

PRIMARY BUSINESS DYNAMICS. Entry into the interstate pipeline business requires substantial upfront capital for construction, thus providing a formidable barrier to entry, in our view. Consequently, the transportation rates charged are regulated in the U.S. by the Federal Energy Regulatory Commission (FERC). Pipeline companies must formally present a detailed proposal for the construction and management of their transportation vehicle; the FERC sets the transportation rates to allow for the recovery of costs plus a proscribed return on investment. In many cases, customers of a particular pipeline have very limited substitute transportation vehicles, resulting in a franchise for the pipeline company whose profitability is governed by the production growth inherent in the source end of the pipeline and the demographic growth of the other end.

While most northern master limited partnership (MLP) pipeline projects were originally financed to transport Canada's vast natural gas resources to the U.S., the increasing economic viability of its oil sands resources has led to their rapid development, in our opinion, into commercial oil uses, which ultimately has led to increased demand for petroleum transportation. While we believe the location of EEP's pipeline directly in the path of the great Alberta fields and its destination in Chicago -- the most central transfer location for the world's largest consumer of energy -- to be the most compelling, we do acknowledge the existence of significant pipeline capacity already directed at the oil sands and to the U.S. market.

FINANCIAL TRENDS. EEP has underperformed some other MLPs during the past few years, due, in our opinion, to the transition of Canadian petroleum production from conventional sources to the vast and still developing unconventional oil sands. We think the Lakehead system has thus been underutilized in anticipation of substantial oil sands production. We believe the performance during 2007 illustrated a turning point toward higher volume growth. Given that the rates on much of this traffic are regulated, we believe EEP has planned significant capacity expansion such that returns on invested capital could approach 8% over the next three to five years, from about 5.5% over the past five years.

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Domicile
Delaware

Founded
1991

Employees
0

Stockholders
80,000

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Enbridge Energy Partners LP

STANDARD &POOR'S

Quantitative Evaluations

S&P Fair Value Rank 3- | 1 | 2 | **3** | 4 | 5 |
LOWEST HIGHEST
Based on S&P's proprietary quantitative model, stocks are ranked from most overvalued (1) to most undervalued (5).

Fair Value Calculation $31.10 Analysis of the stock's current worth, based on S&P's proprietary quantitative model suggests that EEP is fairly valued

Investability Quotient Percentile 50
LOWEST = 1 HIGHEST = 100
EEP scored higher than 50% of all companies for which an S&P Report is available.

Volatility LOW | **AVERAGE** | HIGH

Technical Evaluation BULLISH Since January, 2009, the technical indicators for EEP have been BULLISH.

Insider Activity NA UNFAVORABLE | NEUTRAL | FAVORABLE

Expanded Ratio Analysis

	2007	2006	2005	2004
Price/Sales	0.60	0.53	0.42	0.67
Price/EBITDA	9.00	6.64	8.74	8.09
Price/Pretax Income	19.65	12.17	30.56	20.93
P/E Ratio	20.11	12.17	30.56	20.93
Avg. Diluted Shares Outstg (M)	86.3	70.2	62.1	56.1

Figures based on calendar year-end price

Key Growth Rates and Averages

Past Growth Rate (%)	1 Year	3 Years	5 Years	9 Years
Sales	11.89	17.25	39.47	56.77
Net Income	-23.87	28.58	23.82	15.06
Ratio Analysis (Annual Avg.)				
Net Margin (%)	2.98	2.91	3.09	8.71
% LT Debt to Capitalization	54.34	53.99	52.85	53.78
Return on Equity (%)	9.40	10.86	10.49	10.43

Company Financials Fiscal Year Ended Dec. 31

Per Share Data ($)	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998
Tangible Book Value	24.96	21.73	15.62	18.05	18.13	16.90	19.34	18.36	20.08	18.73
Cash Flow	4.43	5.98	3.66	4.61	4.38	4.31	3.40	4.20	4.88	4.96
Earnings	2.08	3.62	1.06	2.06	1.93	1.76	0.98	1.78	2.48	3.07
S&P Core Earnings	2.08	3.56	0.77	2.06	1.93	1.76	0.98	NA	NA	NA
Dividends	3.72	3.70	3.70	3.70	3.70	3.60	3.50	3.50	3.49	3.36
Payout Ratio	179%	102%	NM	180%	192%	NM	NM	197%	141%	109%
Prices:High	61.82	50.99	57.08	51.95	52.93	46.75	49.60	43.49	48.75	54.00
Prices:Low	48.25	42.00	42.00	41.35	41.70	35.68	38.90	32.00	32.25	43.00
P/E Ratio:High	30	14	54	25	27	27	51	24	20	18
P/E Ratio:Low	23	12	40	20	22	20	40	18	13	14
Income Statement Analysis (Million $)										
Revenue	7,283	6,509	6,477	4,292	3,172	1,186	340	306	313	288
Operating Income	484	522	312	358	194	138	160	178	188	147
Depreciation, Depletion and Amortization	166	135	138	121	97.4	79.9	63.8	61.1	57.8	41.0
Interest Expense	147	111	108	88.4	85.0	59.2	59.3	59.4	54.1	22.0
Pretax Income	222	285	89.2	138	112	77.6	39.4	60.9	79.6	89.0
Effective Tax Rate	2.30%	NM	NM	NM	NM	NM	NM	NM	NM	NM
Net Income	217	285	89.2	138	112	78.1	38.9	60.2	78.7	89.0
S&P Core Earnings	217	280	71.1	138	112	78.1	38.9	NA	NA	NA
Balance Sheet & Other Financial Data (Million $)										
Cash	50.5	185	89.8	78.3	64.4	60.3	40.2	37.2	40.0	47.0
Current Assets	960	1,009	985	626	409	298	115	86.9	86.4	111
Total Assets	6,892	5,224	4,428	3,763	3,232	2,835	1,649	1,377	1,414	1,414
Current Liabilities	1,124	962	971	557	589	359	286	38.3	39.5	102
Long Term Debt	3,024	2,066	1,835	1,559	1,289	1,011	715	799	784	815
Common Equity	2,572	2,043	1,364	1,398	1,313	992	644	536	586	490
Total Capital	5,564	4,110	3,199	2,957	2,602	2,003	1,363	1,338	1,374	1,308
Capital Expenditures	1,980	864	345	289	129	215	35.0	21.7	82.9	487
Cash Flow	383	420	227	259	209	158	103	121	137	130
Current Ratio	0.9	1.0	1.0	1.1	0.7	0.8	0.4	2.3	2.2	1.1
% Long Term Debt of Capitalization	53.8	50.3	57.4	52.7	49.5	50.5	52.5	59.7	57.1	62.3
% Return on Assets	3.6	5.9	2.2	4.0	3.7	3.5	2.6	4.3	5.6	7.2
% Return on Equity	9.4	16.7	6.5	10.2	9.7	9.5	6.6	10.7	14.6	17.9

Data as orig reptd.; bef. results of disc opers/spec. items. Per share data adj. for stk. divs.; EPS diluted. E-Estimated. NA-Not Available. NM-Not Meaningful. NR-Not Ranked. UR-Under Review.

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Enbridge Energy Partners LP

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Sub-Industry Outlook

Our fundamental outlook for the oil and gas storage and transportation sub-industry for the next 12 months is neutral. We expect fee-based pipeline and terminal operators to continue to expand earnings well in excess of anticipated real U.S. GDP growth in 2008 and 2009. As of January, S&P estimated a 1.1% increase in U.S. real GDP for 2008 and a 2.0% decline for 2009, compared to the 2.0% rise in 2007. However, we believe that investors are concerned that the tightening credit market may hinder MLPs from raising capital to fund their expansion projects. In response to the poor credit environment and weak economy, many MLPs plan to reduce their capital expansion budgets for 2009 to preserve capital and maintain their dividends.

We believe that 2009 will be a volatile year for tanker companies. Based on industry research group Bassoe, daily spot charter rates for VLCCs were $66,000 in the fourth quarter of 2008, below the $91,000 average in the third quarter. We expect tanker rates to continue to soften in 2009, due to the expected increase in the worldwide fleet, cuts in OPEC production, and the slowing global economy. The shipping industry suffered from increased piracy in 2008. If piracy is not curtailed, many shippers will re-route their vessels, leading to longer and more expensive trips, in our opinion.

As of early January 2009, the Energy Information Administration (EIA) estimated that U.S. petroleum consumption declined 5.7% in 2008 and would fall another 2.0% in 2009, after being little changed in 2007. The EIA also estimated that natural gas consumption would increase 0.7% in 2008 and decline 1.0% in 2009. Longer term, we think drivers for new transportation infrastructure include new import terminals for liquefied natural gas, transcontinental movement of gas from the Rockies to Northeast markets, and increased oil sands production in Alberta. In our view, an active merger and acquisition environment will also remain a principal investor focus. Current yields as of February 3, 2009, on our universe of MLPs averaged about 11.0%, above the benchmark 10-year Treasury note, which was yielding about 2.83% at that time.

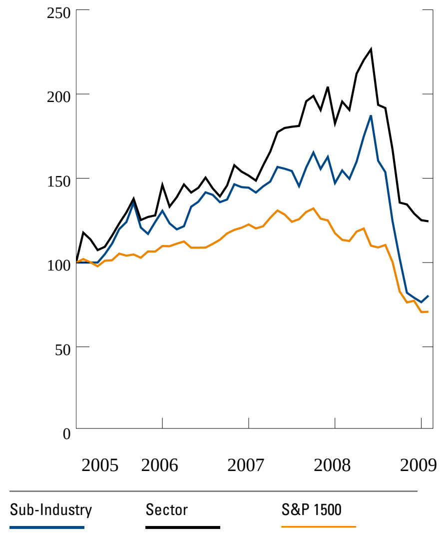
Year to date through February 2, the S&P Oil and Gas Storage and Transportation Index rose 1.1%, versus a 8.6% decline for the S&P 1500. In 2008, the S&P Oil and Gas Storage and Transportation Index was down 10.5%, versus a 38.2% decline for the S&P 1500. Our preference is for those issues with the potential to increase cash flow and dividend payouts over time.

--T. Shafi

Stock Performance

GICS Sector: **Energy**
Sub-Industry: **Oil & Gas Storage & Transportation**

Based on S&P 1500 Indexes
Month-end Price Performance as of 01/30/09



NOTE: All Sector & Sub-Industry information is based on the Global Industry Classification Standard (GICS)

Sub-Industry : Oil & Gas Storage & Transportation Peer Group*: Midstream Energy - Master Limited Partnership

Peer Group	Stock Symbol	Stk.Mkt. Cap. (Mil. $)	Recent Stock Price($)	52 Week High/Low($)	Beta	Yield (%)	P/E Ratio	Fair Value Calc.($)	Quality Ranking	S&P IQ %ile	Return on Revenue (%)	LTD to Cap (%)
Enbridge Energy Ptnrs L.P.	**EEP**	**1,865**	**31.16**	**53.45/22.33**	**0.36**	**12.7**	**9**	**31.10**	**NR**	**50**	**3.0**	**53.8**
Atlas Pipeline Ptnrs LP	APL	317	6.90	45.10/4.68	1.30	22.0	NM	NA	NR	20	NM	49.1
Buckeye Ptnrs L.P.	BPL	2,001	41.37	51.09/22.00	0.08	8.6	13	38.60	NR	70	29.9	43.3
Copano Energy L.L.C.	CPNO	799	16.53	39.75/8.80	1.45	13.9	14	NA	NR	23	5.5	41.3
Holly Energy Ptnrs L.P.	HEP	466	28.52	47.03/14.93	0.41	10.7	21	NA	NR	34	21.5	NA
Kinder Morgan Egy Ptnrs L.P.	KMP	9,057	50.58	60.89/35.59	0.17	8.3	25	44.70	NR	70	11.3	56.6
Magellan Midstream Hldgs L.P.	MGG	1,034	16.51	25.96/11.28	0.39	8.7	12	NA	NR	60	7.1	NA
Magellan Midstream Partners L.P.	MMP	2,369	35.49	45.00/18.85	0.05	8.0	11	32.10	NR	91	28.6	NA
MarkWest Energy Ptnrs L.P.	MWE	672	11.87	38.50/6.55	0.62	21.6	14	NA	NR	78	2.6	47.5
NuStar Energy L.P.	NS	2,646	48.58	55.11/27.00	0.03	8.7	12	43.20	NR	94	5.3	NA
ONEOK Partners L.P.	OKS	2,561	47.06	64.87/35.61	0.45	9.2	8	41.90	NR	94	7.0	54.2
Plains All Amer Pipeline LP	PAA	4,912	39.96	50.96/23.25	0.51	8.8	15	36.10	NR	88	1.4	47.9
Sunoco Logistics Ptnrs LP	SXL	1,576	54.98	56.00/27.62	0.25	7.2	11	NA	NR	92	2.1	46.6
TC Pipelines L.P.	TCLP	882	25.29	37.29/18.11	0.75	11.2	9	27.10	NR	79	64.8	38.7
Teppco Ptnrs L.P.	TPP	2,510	24.01	38.61/16.90	0.03	12.1	15	16.50	NR	53	2.9	54.4

NA-Not Available NM-Not Meaningful NR-Not Rated. *For Peer Groups with more than 15 companies or stocks, selection of issues is based on market capitalization.

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Enbridge Energy Partners LP

S&P Analyst Research Notes and other Company News

February 2, 2009
11:43 am ET ... S&P MAINTAINS HOLD OPINION ON LP UNITS OF ENBRIDGE ENERGY PARTNERS (EEP 31.18***): EEP posts Q4 earnings per unit of $1.04 vs. $0.59, ahead of our $0.68 estimate and Street's $0.65. Results benefited from the start-up of the company's Southern Access Expansion Stage 1 and Clarity projects. The company also gained from higher tariffs at its liquids business segment. We are maintaining our '09 earnings per unit estimate at $2.95. We also keep our 12-month target price at $34, based on a target yield of 11.6% on our estimated 12-month forward distributions projection of $3.96. /T.Shafi

January 8, 2009
02:22 pm ET ... S&P MAINTAINS HOLD OPINION ON LP UNITS OF ENBRIDGE ENERGY PARTNERS (EEP 29.49***): Ahead of EEP's Q4 results, we are decreasing our Q4 earnings per unit forecast to $0.68 from $0.81, based on expected lower operating margins from the company's natural gas segment. We expect that the recessionary environment in 2009 will impact EEP's natural gas business and we are lowering our 2009 earnings per unit estimate to $2.95 from $3.42. We are also decreasing our 12-month target price to $34 from $42, based on a target yield of 11.6% on our projected 12-month forward distributions of $3.96. /T.Shafi

January 8, 2009
02:41 pm ET ... S&P MAINTAINS HOLD OPINION ON SHARES OF ENBRIDGE ENERGY MANAGEMENT (EEQ 28.47***): Ahead of Q4 results, we are reducing our Q4 earnings per unit forecast to $0.62 from $0.80, to reflect lower margins at Enbridge Energy Partners (EEP 29.43***). EEQ's only earning asset is its 14.5% interest in EEP. We also expect the recessionary environment to impact EEP's natural gas segment in '09 and we are lowering our '09 earnings per unit projection for EEQ to $2.46 from $3.25. We are cutting our 12-month target price to $33 from $43, based on a target yield of 12% on our estimate of 12-month forward distributions. /T.Shafi

October 31, 2008
10:23 am ET ... S&P MAINTAINS HOLD OPINION ON LP UNITS OF ENBRIDGE ENERGY PARTNERS (EEP 38.32***): Q3 earnings per unit of $1.09 vs. $0.75 is higher than our view of $0.80. Results reflect better-than-expected performance at the liquids segments. Operating income for liquids segment rose 66% to $95.5 million, reflecting a new surcharge at Lakehead system and higher tariffs. Reflecting Q3 results, we are raising our '08 earnings per unit estimate to $3.39 from $3.10, but cut '09's by $0.58 to $3.42 in slowed economy. We are also raising our target price to $42 from $29, based on a target yield of 9.5% on our estimated 12-month forward distributions projection. /T.Shafi

October 31, 2008
03:09 pm ET ... S&P MAINTAINS HOLD OPINION ON SHARES OF ENBRIDGE ENERGY MANAGEMENT (EEQ 37.88***): EEQ posts Q3 earnings per unit of $0.67 vs. $0.48, two cents above our estimate of $0.65. EEQ's only earning asset is its 14.5% interest in Enbridge Energy Partners (EEP 37.58, Hold). EEP benefited from strong results at its liquids segment, and based on its Q3 results and improving performance, we are increasing our '08 earnings per unit estimate for EEQ to $2.70 from $2.58. We are also raising our 12-month target price to $43 from $28, based on target yield of 9.2% on our estimated 12-month forward distributions projection. /T.Shafi

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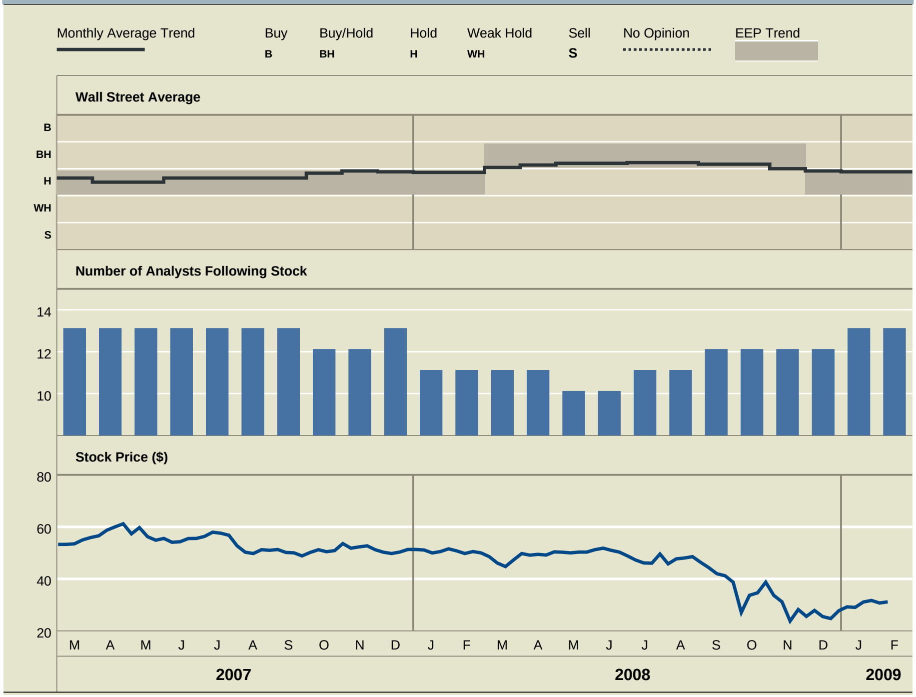
Enbridge Energy Partners LP

STANDARD &POOR'S

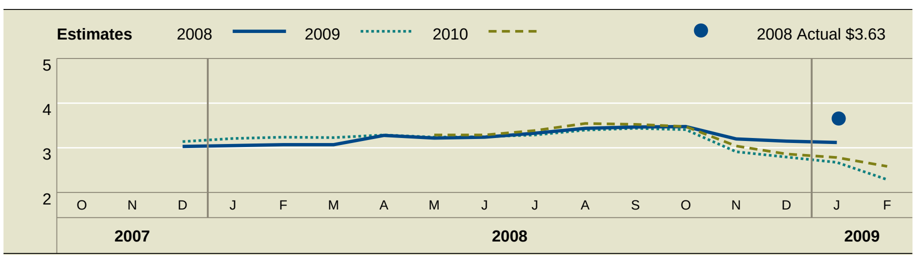
Analysts' Recommendations



Of the total 13 companies following EEP, 13 analysts currently publish recommendations.

	No. of Ratings	% of Total	1 Mo. Prior	3 Mos. Prior
Buy	3	23	3	3
Buy/Hold	1	8	1	1
Hold	7	54	7	7
Weak Hold	2	15	2	1
Sell	0	0	0	0
No Opinion	0	0	0	1
Total	**13**	**100**	**13**	**13**

Wall Street Consensus Estimates



Fiscal Years	Avg Est.	High Est.	Low Est.	# of Est.	Est. P/E
2010	2.59	3.17	2.08	10	12.0
2009	2.29	2.95	1.95	13	13.6
2010 vs. 2009	▲ 13%	▲ 7%	▲ 7%	▼ -23%	▼ -12%
Q1'10	0.55	0.62	0.48	2	56.7
Q1'09	0.54	0.63	0.45	10	57.7
Q1'10 vs. Q1'09	▲ 2%	▼ -2%	▲ 7%	▼ -80%	▼ -2%

A company's earnings outlook plays a major part in any investment decision. Standard & Poor's organizes the earnings estimates of over 2,300 Wall Street analysts, and provides their consensus of earnings over the next two years. This graph shows the trend in analyst estimates over the past 15 months.

Wall Steet Consensus Opinion

HOLD

Companies Offering Coverage

Argus Research Corp.
Barclays Capital
Deutsche Bank
Goldman Sachs & Co.
Merrill Lynch Research
Morgan Stanley & Company
Oppenheimer
Pickering Energy Partners, Inc.
RBC Capital Markets (US)
Sanders Morris Harris
Smith Barney
UBS Warburg
Wachovia Securities

Wall Street Consensus vs. Performance

For fiscal year 2009, analysts estimate that EEP will earn $2.29. For fiscal year 2010, analysts estimate that EEP's earnings per share will grow by 13% to $2.59.

Source: S&P,I/B/E/S International, Inc.
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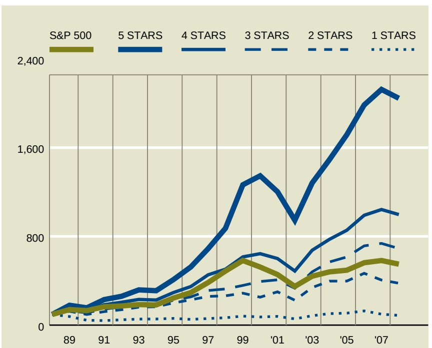
Enbridge Energy Partners LP

STANDARD & POOR'S

Glossary

S&P STARS
Since January 1, 1987, Standard and Poor's Equity Research Services has ranked a universe of common stocks based on a given stock's potential for future performance. Under proprietary STARS (STock Appreciation Ranking System), S&P equity analysts rank stocks according to their individual forecast of a stock's future total return potential versus the expected total return of a relevant benchmark (e.g., a regional index (S&P Asia 50 Index, S&P Europe 350 Index or S&P 500 Index)), based on a 12-month time horizon. STARS was designed to meet the needs of investors looking to put their investment decisions in perspective.

STARS Average Annual Performance



S&P 12-Month Target Price
The S&P equity analyst's projection of the market price a given security will command 12 months hence, based on a combination of intrinsic, relative, and private market valuation metrics.

Investment Style Classification
Characterizes the stock as Growth or Value, and indicates its capitalization level. Growth is evaluated along three dimensions (earnings, sales and internal growth), while Value is evaluated along four dimensions (book-to-price, cash flow-to-price, dividend yield and sale-to-price). Growth stocks score higher than the market average on growth dimensions and lower on value dimensions. The reverse is true for Value stocks. Certain stocks are classified as Blend, indicating a mixture of growth and value characteristics and cannot be classified as purely growth or value.

Qualitative Risk Assessment
The S&P equity analyst's view of a given company's operational risk, or the risk of a firm's ability to continue as an ongoing concern. The Qualitative Risk Assessment is a relative ranking to the S&P U.S. STARS universe, and should be reflective of risk factors related to a company's operations, as opposed to risk and volatility measures associated with share prices.

Quantitative Evaluations
In contrast to our qualitative STARS recommendations, which are assigned by S&P analysts, the quantitative evaluations described below are derived from proprietary arithmetic models. These computer-driven evaluations may at times contradict an analyst's qualitative assessment of a stock. One primary reason for this is that different measures are used to determine each. For instance, when designating STARS, S&P analysts assess many factors that cannot be reflected in a model, such as risks and opportunities, management changes, recent competitive shifts, patent expiration, litigation risk, etc.

S&P Quality Ranking
Growth and stability of earnings and dividends are deemed key elements in establishing S&P's Quality Rankings for common stocks, which are designed to capsulize the nature of this record in a single symbol. It should be noted, however, that the process also takes into consideration certain adjustments and modifications deemed desirable in establishing such rankings. The final score for each stock is measured against a scoring matrix determined by analysis of the scores of a large and representative sample of stocks. The range of scores in the array of this sample has been aligned with the following ladder of rankings:

A+	Highest	B	Below Average
A	High	B-	Lower
A-	Above Average	C	Lowest
B+	Average	D	In Reorganization
NR	Not Ranked		

S&P Fair Value Rank
Using S&P's exclusive proprietary quantitative model, stocks are ranked in one of five groups, ranging from Group 5, listing the most undervalued stocks, to Group 1, the most overvalued issues. Group 5 stocks are expected to generally outperform all others. A positive (+) or negative (-) Timing Index is placed next to the Fair Value ranking to further aid the selection process.A stock with a (+) added to the Fair Value Rank simply means that this stock has a somewhat better chance to outperform other stocks with the same Fair Value Rank. A stock with a (-) has a somewhat lesser chance to outperform other stocks with the same Fair Value Rank. The Fair Value rankings imply the following: 5-Stock is significantly undervalued; 4-Stock is moderately undervalued; 3-Stock is fairly valued; 2-Stock is modestly overvalued; 1-Stock is significantly overvalued.

S&P Fair Value Calculation
The price at which a stock should trade at, according to S&P's proprietary quantitative model that incorporates both actual and estimated variables (as opposed to only actual variables in the case of S&P Quality Ranking). Relying heavily on a company's actual return on equity, the S&P Fair Value model places a value on a security based on placing a formula-derived price-to-book multiple on a company's consensus earnings per share estimate.

Insider Activity
Gives an insight as to insider sentiment by showing whether directors, officers and key employees who have proprietary information not available to the general public, are buying or selling the company's stock during the most recent six months.

Funds From Operations FFO
FFO is Funds from Operations and equal to a REIT's net income, excluding gains or losses from sales of property, plus real estate depreciation.

Investability Quotient (IQ)
The IQ is a measure of investment desirability. It serves as an indicator of potential medium-to-long term return and as a caution against downside risk. The measure takes into account variables such as technical indicators, earnings estimates, liquidity, financial ratios and selected S&P proprietary measures.

S&P's IQ Rationale:
Enbridge Energy Ptnrs L.P.

	Raw Score	Max Value
Proprietary S&P Measures	25	115
Technical Indicators	30	40
Liquidity/Volatility Measures	15	20
Quantitative Measures	23	75
IQ Total	**93**	**250**

Volatility
Rates the volatility of the stock's price over the past year.

Technical Evaluation
In researching the past market history of prices and trading volume for each company, S&P's computer models apply special technical methods and formulas to identify and project price trends for the stock.

Relative Strength Rank
Shows, on a scale of 1 to 99, how the stock has performed versus all other companies in S&P's universe on a rolling 13-week basis.

Global Industry Classification Standard (GICS)
An industry classification standard, developed by Standard & Poor's in collaboration with Morgan Stanley Capital International (MSCI). GICS is currently comprised of 10 Sectors, 24 Industry Groups, 68 Industries, and 154 Sub-Industries.

S&P Issuer Credit Rating
A Standard & Poor's Issuer Credit Rating is a current opinion of an obligor's overall financial capacity (its creditworthiness) to pay its financial obligations. This opinion focuses on the obligor's capacity and willingness to meet its financial commitments as they come due. It does not apply to any specific financial obligation, as it does not take into account the nature of and provisions of the obligation, its standing in bankruptcy or liquidation, statutory preferences, or the legality and enforceability of the obligation. In addition, it does not take into account the creditworthiness of the guarantors, insurers, or other forms of credit enhancement on the obligation. The Issuer Credit Rating is not a recommendation to purchase, sell, or hold a financial obligation issued by an obligor, as it does not comment on market price or suitability for a particular investor. Issuer Credit Ratings are based on current information furnished by obligors or obtained by Standard & Poor's from other sources it considers reliable. Standard & Poor's does not perform an audit in connection with any Issuer Credit Rating and may, on occasion, rely on unaudited financial information. Issuer Credit Ratings may be changed, suspended, or withdrawn as a result of changes in, or unavailability of, such information, or based on other circumstances.

Exchange Type
ASE - American Stock Exchange; NNM - Nasdaq National Market; NSC - Nasdaq SmallCap; NYSE - New York Stock Exchange; BB - OTC Bulletin Board; OT - Over-the-Counter; TO - Toronto Stock Exchange.

S&P Equity Research Services
Standard & Poor's Equity Research Services U.S. includes Standard & Poor's Investment Advisory Services LLC; Standard & Poor's Equity Research Services Europe includes Standard & Poor's LLC-London and Standard & Poor's AB (Sweden); Standard & Poor's Equity Research Services Asia includes Standard & Poor's LLC's offices in Hong Kong, Singapore and Tokyo, Standard & Poor's Malaysia Sdn Bhd, and Standard & Poor's Information Services (Australia) Pty Ltd.

Abbreviations Used in S&P Equity Research Reports
CAGR- Compound Annual Growth Rate; **CAPEX**- Capital Expenditures; **CY**- Calendar Year; **DCF**- Discounted Cash Flow; **EBIT**- Earnings Before Interest and Taxes; **EBITDA**- Earnings Before Interest, Taxes, Depreciation and Amortization; **EPS**- Earnings Per Share; **EV**- Enterprise Value; **FCF**- Free Cash Flow; **FFO**- Funds From Operations; **FY**- Fiscal Year; **P/E**- Price/Earnings ; **PEG Ratio**- P/E-to-Growth Ratio; **PV**- Present Value; **R&D**- Research & Development; **ROE**- Return on Equity; **ROI**- Return on Investment; **ROIC**- Return on Invested Capital; **ROA**- Return on Assets; **SG&A**- Selling, General & Administrative Expenses; **WACC**- Weighted Average Cost of Capital

Dividends on American Depository Receipts (ADRs) and American Depository Shares (ADSs) are net of taxes (paid in the country of origin).

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Enbridge Energy Partners LP

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S&P Global STARS Distribution

In North America: As of December 31, 2008, research analysts at Standard & Poor's Equity Research Services U.S. have recommended 27.0% of issuers with buy recommendations, 61.2% with hold recommendations and 11.8% with sell recommendations.

In Europe: As of December 31, 2008, research analysts at Standard & Poor's Equity Research Services Europe have recommended 30.4% of issuers with buy recommendations, 45.3% with hold recommendations and 24.3% with sell recommendations.

In Asia: As of December 31, 2008, research analysts at Standard & Poor's Equity Research Services Asia have recommended 33.9% of issuers with buy recommendations, 54.4% with hold recommendations and 11.7% with sell recommendations.

Globally: As of December 31, 2008, research analysts at Standard & Poor's Equity Research Services globally have recommended 28.1% of issuers with buy recommendations, 58.3% with hold recommendations and 13.6% with sell recommendations.

★★★★★ **5-STARS (Strong Buy)**: Total return is expected to outperform the total return of a relevant benchmark, by a wide margin over the coming 12 months, with shares rising in price on an absolute basis.

★★★★☆ **4-STARS (Buy)**: Total return is expected to outperform the total return of a relevant benchmark over the coming 12 months, with shares rising in price on an absolute basis.

★★★☆☆ **3-STARS (Hold)**: Total return is expected to closely approximate the total return of a relevant benchmark over the coming 12 months, with shares generally rising in price on an absolute basis.

★★☆☆☆ **2-STARS (Sell)**: Total return is expected to underperform the total return of a relevant benchmark over the coming 12 months, and the share price not anticipated to show a gain.

★☆☆☆☆ **1-STARS (Strong Sell)**: Total return is expected to underperform the total return of a relevant benchmark by a wide margin over the coming 12 months, with shares falling in price on an absolute basis.

Relevant benchmarks: In North America the relevant benchmark is the S&P 500 Index, in Europe and in Asia, the relevant benchmarks are generally the S&P Europe 350 Index and the S&P Asia 50 Index.

For All Regions: All of the views expressed in this research report accurately reflect the research analyst's personal views regarding any and all of the subject securities or issuers. No part of analyst compensation was, is, or will be directly or indirectly, related to the specific recommendations or views expressed in this research report.

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Source: S&P.

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STANDARD &POOR'S

Enterprise Products Partners LP

S&P Recommendation HOLD ★★★★★ | **Price** $23.23 (as of Feb 13, 2009) | **12-Mo. Target Price** $27.00

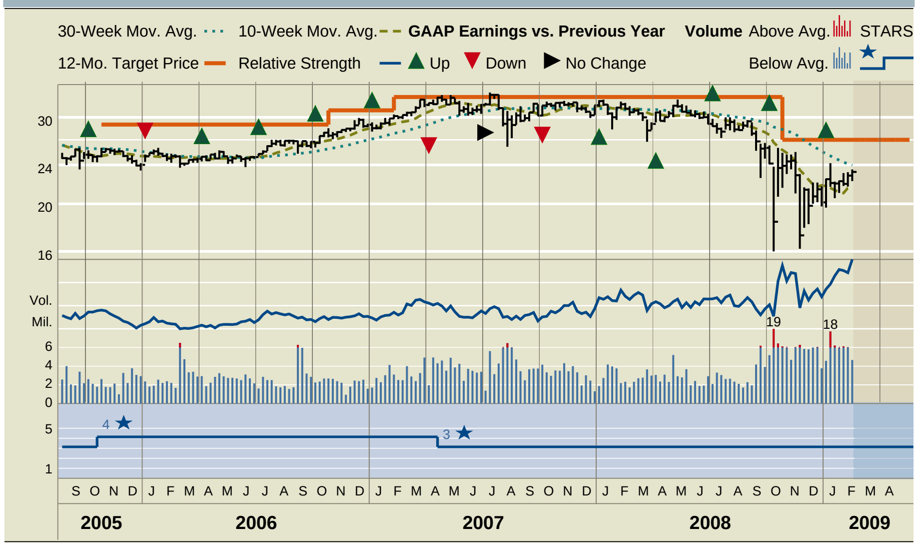
GICS Sector Energy
Sub-Industry Oil & Gas Storage & Transportation

Summary This company is an integrated provider of natural gas and natural gas liquids services, including processing, fractionation, storage, transportation and terminalling.

Key Stock Statistics (Source S&P, Vickers, company reports)

52-Wk Range	$32.64– 16.00	S&P Oper. EPS 2008**E**	1.85	Market Capitalization(B)	$10.119	Beta	0.46
Trailing 12-Month EPS	$1.86	S&P Oper. EPS 2009**E**	2.10	Yield (%)	9.13	S&P 3-Yr. Proj. EPS CAGR(%)	9
Trailing 12-Month P/E	12.5	P/E on S&P Oper. EPS 2008**E**	12.6	Dividend Rate/Share	$2.12	S&P Credit Rating	BBB-
$10K Invested 5 Yrs Ago	$14,523	Common Shares Outstg. (M)	435.6	Institutional Ownership (%)	25		

Price Performance



Options: ASE, CBOE, P, Ph

Analysis prepared by **Tanjila Shafi** on February 05, 2009, when the stock traded at **$ 22.73**.

Highlights

➤ We expect rising pipeline volumes to boost earnings and cash flow over the next several years, as EPD has a large portfolio of organic projects that we think offer high potential returns at relatively low risk. Its largest single project, the Independence Hub/Pipeline, began production in early 2007. We project double-digit revenue growth continuing in 2009 as the impact of slower economic growth is partly offset by the inclusion of the Hub/Pipeline. We estimate earnings per unit of $2.10 in 2009, versus 2008's $1.85.

➤ We believe that EPD will benefit from its diversified fee-based assets and from investments in offshore pipeline infrastructure such as the Phase V expansion of the Jonah Gas Gathering System, the Barnett Pipeline project and the Independence Hub and Trail.

➤ EPD announced a fourth-quarter 2008 distribution of $0.53 per unit, a 1.4% increase from a year earlier. We estimate cash distributions for 2009 at $2.15, supported by the company's projects.

Investment Rationale/Risk

➤ EPD has built one of the largest midstream master limited partnerships, partly through acquisitions. We believe EPD's size and financial resources place it in a better position than most peers for expansion without relying on acquisitions. It has a strong asset base, in our view, with access to high-demand markets and major supply sources. EPD has focused on expanding infrastructure to capitalize on strong NGL fundamentals and natural gas drilling in the Rockies and Permian Basin, in our view, and access to growing production in the Gulf of Mexico.

➤ Risks to our recommendation and target price include a greater-than-expected rise in interest rates, and a decline in economic activity that reduces demand for energy commodities and EPD's transportation volumes.

➤ Our 12-month target price of $27 is based on a target yield of 8.0%, on projected cash distributions of $2.15, in line with peers.

Qualitative Risk Assessment

LOW	MEDIUM	HIGH

Our risk assessment is based on EPD's large and diversified asset portfolio, stable, fee-based businesses, and a track record of increasing distribution. This is only partially offset by some exposure to cyclical swings in demand for commodity transportation.

Quantitative Evaluations

S&P Quality Ranking B+

D	C	B-	B	B+	A-	A	A+

Relative Strength Rank STRONG

80

LOWEST = 1 HIGHEST = 99

Revenue/Earnings Data

Revenue (Million $)

	1Q	2Q	3Q	4Q	Year
2008	5,685	6,340	6,298	3,584	21,906
2007	3,323	4,213	4,112	5,302	16,950
2006	3,250	3,518	3,873	3,351	13,991
2005	2,556	2,672	3,249	3,780	12,257
2004	1,705	1,713	2,040	2,863	8,321
2003	1,482	1,211	1,235	1,419	5,346

Earnings Per Share ($)

	1Q	2Q	3Q	4Q	Year
2008	0.52	0.52	0.38	0.43	1.86
2007	0.20	0.26	0.20	0.30	0.96
2006	0.28	0.26	0.43	0.25	1.22
2005	0.25	0.14	0.29	0.24	0.92
2004	0.23	0.11	0.20	0.28	0.83
2003	0.19	0.14	-0.04	0.13	0.41

Fiscal year ended Dec. 31. Next earnings report expected: Late April. EPS Estimates based on S&P Operating Earnings; historical GAAP earnings are as reported.

Dividend Data (Dates: mm/dd Payment Date: mm/dd/yy)

Amount ($)	Date Decl.	Ex-Div. Date	Stk. of Record	Payment Date
0.508	04/15	04/28	04/30	05/07/08
0.515	07/16	07/29	07/31	08/07/08
0.523	10/08	10/29	10/31	11/12/08
0.530	01/08	01/28	01/30	02/09/09

Dividends have been paid since 1998. Source: Company reports.

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STANDARD &POOR'S

Enterprise Products Partners LP

Business Summary February 05, 2009

CORPORATE OVERVIEW. Enterprise Products Partners L.P., a publicly traded limited partnership, is an integrated provider of natural gas pipeline and processing services and natural gas liquids (NGL) fractionation, storage, transportation and terminalling services. EPD believes it is a leader in developing midstream infrastructure in the deepwater of the Gulf of Mexico.

EPD was formed in April 1998 to acquire, own and operate the NGL business of Enterprise Products Co. (EPCO). Enterprise Products GP, LLC, a wholly owned subsidiary of EPCO, is the general partner; it holds a 2% general partner interest in both EPD and the operating partnership.

The NGL Pipelines segment (54% of gross operating profits in 2007) includes natural gas processing and related NGL marketing, 13,758 miles of NGL pipelines, and NGL fractionation facilities located in Texas and Louisiana. The core business includes the Mid-America, Seminole and Dixie pipeline systems.

The Onshore Natural Gas Pipelines segment (22%) includes interests in about 17,758 miles of pipelines that gather and transport natural gas in Alabama, Colorado, Louisiana, Mississippi, New Mexico and Texas. In addition, EPD owns two underground salt dome natural gas storage facilities in Mississippi.

The Petrochemical Services segment (12%) includes four propylene fractionation facilities, an isomerization complex and an octane additive production facility. This segment also includes 683 miles of petrochemical pipeline systems.

The Offshore Pipelines segment (12%) owns an interest in about 1,555 miles of natural gas pipelines, 914 miles of crude oil pipeline systems, and six multi-purposed offshore hub platforms serving the Gulf of Mexico.

CORPORATE STRATEGY. EPD's business strategy is to capitalize on expected increases in natural gas, NGL and crude oil production resulting from development activities in the Rocky Mountain region and Gulf of Mexico; maintain a balanced portfolio of midstream energy assets and expand this asset base through growth capital projects and accretive acquisitions of complementary midstream assets; share capital costs and risks through joint ventures or alliances with strategic partners that will provide the raw materials for these projects; and increase fee-based cash flows by investing in pipelines and other fee-based businesses and de-emphasize commodity-based activities.

On August 18, 2008, EPD and TEPPCO Partners, L.P. (TPP) and Oiltanking Holdings Americas, Inc. announced that they had formed a joint venture to design, construct, own and operate a new Texas offshore crude oil port and pipeline system for the delivery of waterborne crude oil to refining centers along the upper Texas Gulf Coast. Each company is expected to invest $600 million in the project, which is scheduled for completion in 2010.

In August 2006, EPD and TEPPCO Partners, L.P. (TPP) announced a joint venture through their respective subsidiaries in which they will be partners in Jonah Gas Gathering Company (JGG). JGG owns the Jonah Gas Gathering System, located in the Greater Green River Basin of southwestern Wyoming, which gathers and transports natural gas produced from the prolific Jonah and Pinedale fields to natural gas processing plants and major interstate pipelines that deliver the natural gas to end-use markets.

PRIMARY BUSINESS DYNAMICS. Part of EPD's business strategy involves expansion through business combinations, growth capital projects and investments in joint ventures. EPD believes it is well positioned to continue to grow through construction of new facilities and acquisitions that will expand its system of assets through growth capital projects.

Growth spending in 2005 was $743.8 million, which included $338.6 million for the Independence Hub offshore platform and related Independence Trail Pipeline and $90.1 million for the Constitution Oil and Constitution Gas Pipelines. In addition, EPD completed $327 million of acquisitions during 2005, the largest of which was the $145.5 million purchase of underground NGL storage facilities and propane terminals from Ferrellgas LP (FGP).

EPD's net capital spending in 2006, including cash and equity issued for acquisitions and investments in unconsolidated affiliates, was $1.8 billion, which also included $119 million of sustaining capital expenditures and $181 million of equity issued in association with the acquisition of assets from Cerrito Gathering Company, Ltd.

Capital spending totaled $2.5 billion in 2007, with some $2.0 billion used for growth projects, $142 million for ongoing operations, $343 million for unconsolidated affiliates and $47 million for acquisitions. Capital spending totaled $2.3 billion in 2008, with about $2.1 billion for growth projects. The company plans to spend $800 million on capital expenditures in 2009.

FINANCIAL TRENDS. In January 2009, EPD announced an increase in its quarterly cash distribution rate to partners to $0.53 per common unit. This distribution represents a 6.0% increase over the $0.50 per unit quarterly distribution paid a year earlier. Our estimated 2009 coverage ratio is 1.1X.

Corporate Information

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Chrmn
D.L. Duncan

EVP & CFO
W.R. Fowler

Pres & CEO
M.A. Creel

EVP, Secy & General Counsel
R.H. Bachmann

COO & EVP
W. Ordemann

Board Members
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E. W. Barnett
M. A. Creel
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Stockholders
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Enterprise Products Partners LP

STANDARD &POOR'S

Quantitative Evaluations

S&P Fair Value Rank 1-

1	2	3	4	5

LOWEST — HIGHEST

Based on S&P's proprietary quantitative model, stocks are ranked from most overvalued (1) to most undervalued (5).

Fair Value Calculation $19.30

Analysis of the stock's current worth, based on S&P's proprietary quantitative model suggests that EPD is overvalued by $3.93 or 16.9%.

Investability Quotient Percentile 87

LOWEST = 1 — HIGHEST = 100

EPD scored higher than 87% of all companies for which an S&P Report is available.

Volatility LOW | **AVERAGE** | HIGH

Technical Evaluation NEUTRAL

Since January, 2009, the technical indicators for EPD have been NEUTRAL.

Insider Activity NA

UNFAVORABLE | NEUTRAL | FAVORABLE

Expanded Ratio Analysis

	2007	2006	2005	2004
Price/Sales	0.82	0.86	0.75	0.83
Price/EBITDA	10.20	10.14	8.60	12.16
Price/Pretax Income	23.90	19.08	21.00	25.54
P/E Ratio	25.95	20.04	21.70	26.72
Avg. Diluted Shares Outstg (M)	434.4	414.8	383.0	266.0

Figures based on calendar year-end price

Key Growth Rates and Averages

Past Growth Rate (%)	1 Year	3 Years	5 Years	9 Years
Sales	21.15	25.44	37.09	39.44
Net Income	-11.01	28.84	50.65	26.46
Ratio Analysis (Annual Avg.)				
Net Margin (%)	3.15	3.63	3.19	4.71
% LT Debt to Capitalization	51.20	63.77	57.38	48.92
Return on Equity (%)	8.46	140.33	87.10	56.71

Company Financials Fiscal Year Ended Dec. 31

Per Share Data ($)	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998
Tangible Book Value	10.62	11.30	10.96	10.55	6.24	5.09	5.43	5.00	5.40	4.16
Cash Flow	2.39	2.52	2.21	1.70	1.13	1.03	1.72	1.59	1.01	0.47
Earnings	0.96	1.22	0.92	0.83	0.41	0.48	1.39	1.32	0.83	0.31
S&P Core Earnings	0.89	1.29	1.09	0.93	0.40	0.47	1.38	NA	NA	NA
Dividends	1.92	1.80	1.66	1.51	1.44	1.33	1.16	1.03	0.90	0.16
Payout Ratio	199%	148%	180%	182%	NM	NM	83%	78%	108%	1%
Prices:High	33.70	29.98	28.35	25.99	24.98	25.80	26.30	15.94	10.34	11.03
Prices:Low	26.14	23.69	23.38	20.00	17.85	15.00	13.25	9.13	7.47	6.88
P/E Ratio:High	35	25	31	31	61	54	19	12	12	36
P/E Ratio:Low	27	20	25	24	44	31	10	7	9	22
Income Statement Analysis (Million $)										
Revenue	16,950	13,991	12,257	8,321	5,346	3,585	3,180	3,073	1,333	739
Operating Income	1,358	1,186	1,069	566	390	289	314	261	144	53.7
Depreciation, Depletion and Amortization	505	447	421	195	128	86.1	51.9	41.0	25.3	19.2
Interest Expense	387	238	231	156	141	102	52.5	33.3	16.4	14.7
Pretax Income	580	630	438	269	114	100	245	223	122	37.3
Effective Tax Rate	2.63%	3.38%	1.91%	1.40%	4.66%	1.63%	NM	NM	NM	NM
Net Income	534	600	424	257	105	95.5	242	221	120	37.3
S&P Core Earnings	501	534	416	246	103	94.4	241	NA	NA	NA
Balance Sheet & Other Financial Data (Million $)										
Cash	92.9	22.6	42.1	50.7	44.3	22.6	138	60.4	5.23	24.1
Current Assets	2,538	1,922	1,971	1,441	687	638	519	581	385	138
Total Assets	16,608	13,990	12,591	11,315	4,803	4,230	2,431	1,952	1,495	741
Current Liabilities	3,045	1,985	1,890	1,586	1,097	721	409	586	531	82.8
Long Term Debt	6,906	5,296	4,834	4,266	1,900	2,231	855	404	166	90.0
Common Equity	6,132	160	5,679	5,329	1,706	1,201	1,147	936	789	562
Total Capital	13,490	5,598	10,616	9,666	3,692	3,501	2,014	1,350	963	658
Capital Expenditures	2,186	1,341	864	156	146	72.1	150	244	21.2	1.90
Cash Flow	1,038	1,047	844	453	233	182	294	262	147	56.5
Current Ratio	0.8	1.0	1.0	0.9	0.6	0.9	1.3	1.0	0.7	1.7
% Long Term Debt of Capitalization	51.3	94.6	45.5	44.1	51.5	63.7	42.5	29.9	17.2	13.7
% Return on Assets	3.5	4.5	3.5	3.2	2.3	2.9	11.1	12.8	10.9	NM
% Return on Equity	8.5	404.8	7.7	7.3	7.2	8.1	23.3	25.6	18.0	NM

Data as orig reptd.; bef. results of disc opers/spec. items. Per share data adj. for stk. divs.; EPS diluted. E-Estimated. NA-Not Available. NM-Not Meaningful. NR-Not Ranked. UR-Under Review.

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Enterprise Products Partners LP

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Sub-Industry Outlook

Our fundamental outlook for the oil and gas storage and transportation sub-industry for the next 12 months is neutral. We expect fee-based pipeline and terminal operators to continue to expand earnings well in excess of anticipated real U.S. GDP growth in 2008 and 2009. As of January, S&P estimated a 1.1% increase in U.S. real GDP for 2008 and a 2.0% decline for 2009, compared to the 2.0% rise in 2007. However, we believe that investors are concerned that the tightening credit market may hinder MLPs from raising capital to fund their expansion projects. In response to the poor credit environment and weak economy, many MLPs plan to reduce their capital expansion budgets for 2009 to preserve capital and maintain their dividends.

We believe that 2009 will be a volatile year for tanker companies. Based on industry research group Bassoe, daily spot charter rates for VLCCs were $66,000 in the fourth quarter of 2008, below the $91,000 average in the third quarter. We expect tanker rates to continue to soften in 2009, due to the expected increase in the worldwide fleet, cuts in OPEC production, and the slowing global economy. The shipping industry suffered from increased piracy in 2008. If piracy is not curtailed, many shippers will re-route their vessels, leading to longer and more expensive trips, in our opinion.

As of early January 2009, the Energy Information Administration (EIA) estimated that U.S. petroleum consumption declined 5.7% in 2008 and would fall another 2.0% in 2009, after being little changed in 2007. The EIA also estimated that natural gas consumption would increase 0.7% in 2008 and decline 1.0% in 2009. Longer term, we think drivers for new transportation infrastructure include new import terminals for liquefied natural gas, transcontinental movement of gas from the Rockies to Northeast markets, and increased oil sands production in Alberta. In our view, an active merger and acquisition environment will also remain a principal investor focus. Current yields as of February 3, 2009, on our universe of MLPs averaged about 11.0%, above the benchmark 10-year Treasury note, which was yielding about 2.83% at that time.

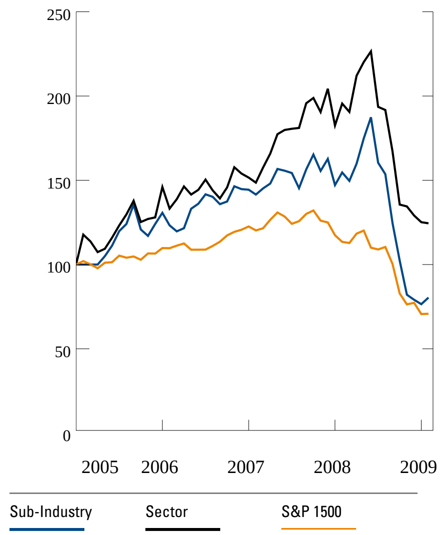
Year to date through February 2, the S&P Oil and Gas Storage and Transportation Index rose 1.1%, versus a 8.6% decline for the S&P 1500. In 2008, the S&P Oil and Gas Storage and Transportation Index was down 10.5%, versus a 38.2% decline for the S&P 1500. Our preference is for those issues with the potential to increase cash flow and dividend payouts over time.

--T. Shafi

Stock Performance

GICS Sector: Energy
Sub-Industry: Oil & Gas Storage & Transportation

Based on S&P 1500 Indexes
Month-end Price Performance as of 01/30/09



NOTE: All Sector & Sub-Industry information is based on the Global Industry Classification Standard (GICS)

Sub-Industry : Oil & Gas Storage & Transportation Peer Group*: Midstream Energy - Master Limited Partnership

Peer Group	Stock Symbol	Stk.Mkt. Cap. (Mil. $)	Recent Stock Price($)	52 Week High/Low($)	Beta	Yield (%)	P/E Ratio	Fair Value Calc.($)	Quality Ranking	S&P IQ %ile	Return on Revenue (%)	LTD to Cap (%)
Enterprise Products Partners	**EPD**	**10,119**	**23.23**	**32.64/16.00**	**0.46**	**9.1**	**12**	**19.30**	**B+**	**87**	**3.2**	**51.3**
Buckeye Ptnrs L.P.	BPL	2,001	41.37	51.09/22.00	0.08	8.6	13	38.60	NR	70	29.9	43.3
Copano Energy L.L.C.	CPNO	799	16.53	39.75/8.80	1.45	13.9	14	NA	NR	23	5.5	41.3
Enbridge Energy Ptnrs L.P.	EEP	1,865	31.16	53.45/22.33	0.36	12.7	9	31.10	NR	50	3.0	53.8
Holly Energy Ptnrs L.P.	HEP	466	28.52	47.03/14.93	0.41	10.7	21	NA	NR	34	21.5	NA
Kinder Morgan Egy Ptnrs L.P.	KMP	9,057	50.58	60.89/35.59	0.17	8.3	25	44.70	NR	70	11.3	56.6
Magellan Midstream Hldgs L.P.	MGG	1,034	16.51	25.96/11.28	0.39	8.7	12	NA	NR	60	7.1	NA
Magellan Midstream Partners L.P.	MMP	2,369	35.49	45.00/18.85	0.05	8.0	11	32.10	NR	91	28.6	NA
MarkWest Energy Ptnrs L.P.	MWE	672	11.87	38.50/6.55	0.62	21.6	14	NA	NR	78	2.6	47.5
NuStar Energy L.P.	NS	2,646	48.58	55.11/27.00	0.03	8.7	12	43.20	NR	94	5.3	NA
ONEOK Partners L.P.	OKS	2,561	47.06	64.87/35.61	0.45	9.2	8	41.90	NR	94	7.0	54.2
Plains All Amer Pipeline LP	PAA	4,912	39.96	50.96/23.25	0.51	8.8	15	36.10	NR	88	1.4	47.9
Sunoco Logistics Ptnrs LP	SXL	1,576	54.98	56.00/27.62	0.25	7.2	11	NA	NR	92	2.1	46.6
TC Pipelines L.P.	TCLP	882	25.29	37.29/18.11	0.75	11.2	9	27.10	NR	79	64.8	38.7
Teppco Ptnrs L.P.	TPP	2,510	24.01	38.61/16.90	0.03	12.1	15	16.50	NR	53	2.9	54.4

NA-Not Available NM-Not Meaningful NR-Not Rated. *For Peer Groups with more than 15 companies or stocks, selection of issues is based on market capitalization.

Source: S&P.
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Enterprise Products Partners LP

S&P Analyst Research Notes and other Company News

February 2, 2009
02:35 pm ET ... S&P MAINTAINS HOLD OPINION ON LP UNITS OF ENTERPRISE PRODUCT PARTNERS (EPD 21.96***): EPD reports Q4 earnings per unit of $0.44 vs. $0.30, below our $0.50 estimate. The effects of Hurricanes Gustav and Ike lowered Q4 earnings by $36 million, or $0.08 per unit. We are encouraged by the 4.0% growth in natural gas liquids, crude oil and petrochemical transportation volumes. We are maintaining our 2009 earnings per unit estimate at $2.10. We are also keeping our 12-month target price at $27, based on expected 12-month forward cash distributions of $2.15 and a target yield of 8%. /T.Shafi

January 26, 2009
Enterprise Products Partners LP announced the departure of James H. Lytal, Executive Vice President, effective January 15, 2009.

January 20, 2009
On January 15, 2009, Enterprise Products Partners LP announced that James H. Lytal notified of his resignation as the general partner of the company, effective immediately.

January 16, 2009
11:20 am ET ... S&P MAINTAINS HOLD OPINION ON LP UNITS OF ENTERPRISE GP HOLDINGS (EPE 19.41***): Ahead of Q4 results, we continue to forecast earnings per unit for the quarter of $0.28 vs. year-ago $0.18. The company's growth in distribution depends on profits and distributable cash flow from its ownership stakes in Enterprise Products Partners (EPD 21.51***), TEPPCO Partners (TPP 24.05***), and Energy Transfer Equity (ETE 17.02, NR). We keep our '09 earnings per unit forecast of $1.47, and we maintain our 12-month target price of $25, based on a target yield of 7.5% on estimated 12-month forward distributions of $1.88. /T.Shafi

December 17, 2008
11:12 am ET ... S&P MAINTAINS HOLD OPINION ON LP UNITS OF ENTERPRISE PRODUCT PARTNERS (EPD 21.14***): Affiliate Enterprise Products Operating LLC, and Questar Pipeline Company, a subsidiary of Questar Corp. (STR 33.72, NR), announce that White River Hub joint venture has commenced services. We note the positive effects of the hub in expanding EPD's western operations and increasing its ability to meet producer needs. We are maintaining our estimate of '09 earnings per unit at $2.10, and keep our 12-month target price at $27, based on projected cash distributions of $2.15 and a target yield of 8%. /T.Shafi

November 11, 2008
11:18 am ET ... S&P MAINTAINS HOLD OPINION ON LP UNITS OF ENTERPRISE GP HOLDINGS (EPE 21.43***): EPE posts Q3 earnings per unit of $0.34 vs. $0.10, ahead of our $0.28 estimate. Growth in the company's distribution to holders depends on profits and distributable cash flow from its ownership stakes in Enterprise Products Partners (EPD 23.90***), TEPPCO Partners (TPP 26.40***) and Energy Transfer Equity (ETE 18.44, NR). Based on Q3 results, we are increasing our '08 earnings per unit estimate to $1.40 from $1.34. We maintain our target price at $25, based on a target yield of 7.3% on estimated 12-month forward distributions of $1.82. /T.Shafi

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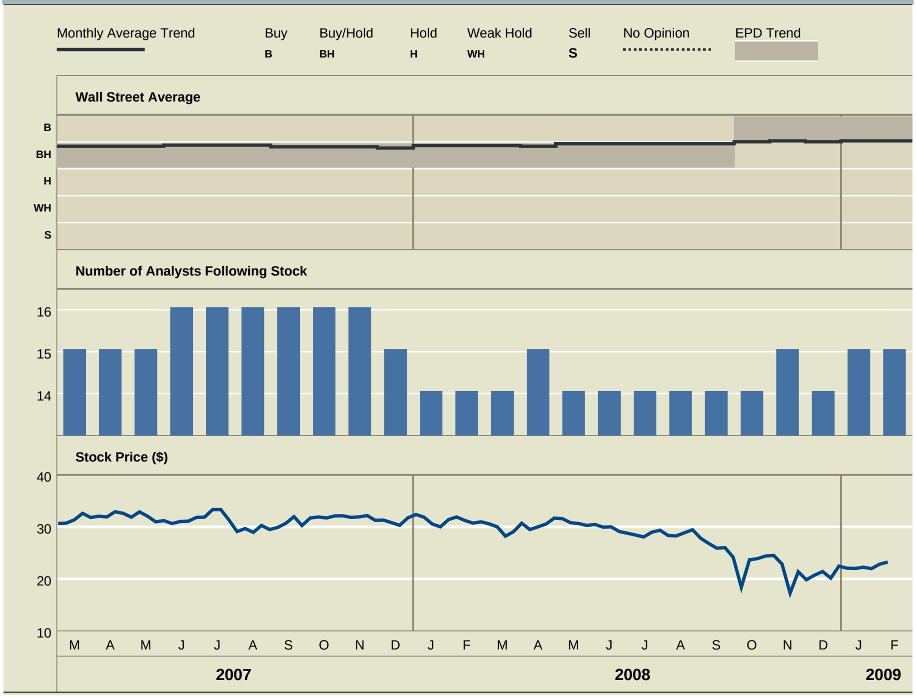
Enterprise Products Partners LP

STANDARD &POOR'S

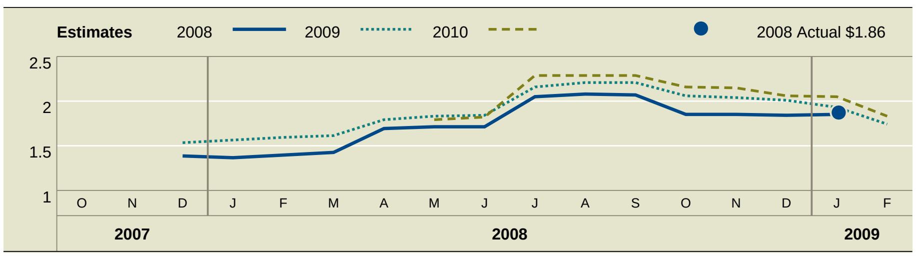
Analysts' Recommendations



Of the total 15 companies following EPD, 15 analysts currently publish recommendations.

	No. of Ratings	% of Total	1 Mo. Prior	3 Mos. Prior
Buy	8	53	8	8
Buy/Hold	7	47	7	7
Hold	0	0	0	0
Weak Hold	0	0	0	0
Sell	0	0	0	0
No Opinion	0	0	0	1
Total	**15**	**100**	**15**	**16**

Wall Street Consensus Estimates



Fiscal Years	Avg Est.	High Est.	Low Est.	# of Est.	Est. P/E
2010	1.84	2.33	1.10	13	12.6
2009	1.75	2.25	1.29	15	13.3
2010 vs. 2009	▲ 5%	▲ 4%	▼ -15%	▼ -13%	▼ -5%
Q1'10	0.39	0.40	0.36	3	59.6
Q1'09	0.38	0.51	0.27	13	61.1
Q1'10 vs. Q1'09	▲ 3%	▼ -22%	▲ 33%	▼ -77%	▼ -2%

A company's earnings outlook plays a major part in any investment decision. Standard & Poor's organizes the earnings estimates of over 2,300 Wall Street analysts, and provides their consensus of earnings over the next two years. This graph shows the trend in analyst estimates over the past 15 months.

Wall Steet Consensus Opinion

BUY

Companies Offering Coverage

Argus Research Corp.
Barclays Capital
Deutsche Bank
Goldman Sachs & Co.
JP Morgan Securities
Merrill Lynch Research
Morgan Stanley & Company
Morgan, Keegan & Company, Inc.
Oppenheimer
RBC Capital Markets (US)
Raymond James & Assoc, Inc.
Sanders Morris Harris
Smith Barney
UBS Warburg
Wachovia Securities

Wall Street Consensus vs. Performance

For fiscal year 2009, analysts estimate that EPD will earn $1.75. For fiscal year 2010, analysts estimate that EPD's earnings per share will grow by 5% to $1.84.

Source: S&P,I/B/E/S International, Inc.
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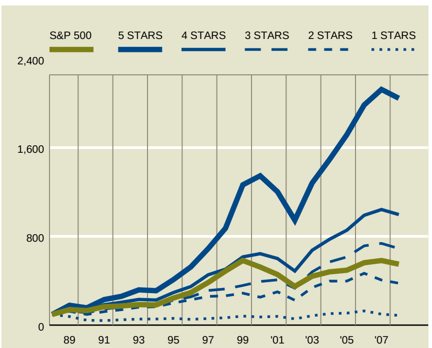
Enterprise Products Partners LP

Glossary

S&P STARS
Since January 1, 1987, Standard and Poor's Equity Research Services has ranked a universe of common stocks based on a given stock's potential for future performance. Under proprietary STARS (STock Appreciation Ranking System), S&P equity analysts rank stocks according to their individual forecast of a stock's future total return potential versus the expected total return of a relevant benchmark (e.g., a regional index (S&P Asia 50 Index, S&P Europe 350 Index or S&P 500 Index)), based on a 12-month time horizon. STARS was designed to meet the needs of investors looking to put their investment decisions in perspective.

STARS Average Annual Performance



S&P 12-Month Target Price
The S&P equity analyst's projection of the market price a given security will command 12 months hence, based on a combination of intrinsic, relative, and private market valuation metrics.

Investment Style Classification
Characterizes the stock as Growth or Value, and indicates its capitalization level. Growth is evaluated along three dimensions (earnings, sales and internal growth), while Value is evaluated along four dimensions (book-to-price, cash flow-to-price, dividend yield and sale-to-price). Growth stocks score higher than the market average on growth dimensions and lower on value dimensions. The reverse is true for Value stocks. Certain stocks are classified as Blend, indicating a mixture of growth and value characteristics and cannot be classified as purely growth or value.

Qualitative Risk Assessment
The S&P equity analyst's view of a given company's operational risk, or the risk of a firm's ability to continue as an ongoing concern. The Qualitative Risk Assessment is a relative ranking to the S&P U.S. STARS universe, and should be reflective of risk factors related to a company's operations, as opposed to risk and volatility measures associated with share prices.

Quantitative Evaluations
In contrast to our qualitative STARS recommendations, which are assigned by S&P analysts, the quantitative evaluations described below are derived from proprietary arithmetic models. These computer-driven evaluations may at times contradict an analyst's qualitative assessment of a stock. One primary reason for this is that different measures are used to determine each. For instance, when designating STARS, S&P analysts assess many factors that cannot be reflected in a model, such as risks and opportunities, management changes, recent competitive shifts, patent expiration, litigation risk, etc.

S&P Quality Ranking
Growth and stability of earnings and dividends are deemed key elements in establishing S&P's Quality Rankings for common stocks, which are designed to capsulize the nature of this record in a single symbol. It should be noted, however, that the process also takes into consideration certain adjustments and modifications deemed desirable in establishing such rankings. The final score for each stock is measured against a scoring matrix determined by analysis of the scores of a large and representative sample of stocks. The range of scores in the array of this sample has been aligned with the following ladder of rankings:

A+	Highest	B	Below Average
A	High	B-	Lower
A-	Above Average	C	Lowest
B+	Average	D	In Reorganization
NR	Not Ranked		

S&P Fair Value Rank
Using S&P's exclusive proprietary quantitative model, stocks are ranked in one of five groups, ranging from Group 5, listing the most undervalued stocks, to Group 1, the most overvalued issues. Group 5 stocks are expected to generally outperform all others. A positive (+) or negative (-) Timing Index is placed next to the Fair Value ranking to further aid the selection process.A stock with a (+) added to the Fair Value Rank simply means that this stock has a somewhat better chance to outperform other stocks with the same Fair Value Rank. A stock with a (-) has a somewhat lesser chance to outperform other stocks with the same Fair Value Rank. The Fair Value rankings imply the following: 5-Stock is significantly undervalued; 4-Stock is moderately undervalued; 3-Stock is fairly valued; 2-Stock is modestly overvalued; 1-Stock is significantly overvalued.

S&P Fair Value Calculation
The price at which a stock should trade at, according to S&P's proprietary quantitative model that incorporates both actual and estimated variables (as opposed to only actual variables in the case of S&P Quality Ranking). Relying heavily on a company's actual return on equity, the S&P Fair Value model places a value on a security based on placing a formula-derived price-to-book multiple on a company's consensus earnings per share estimate.

Insider Activity
Gives an insight as to insider sentiment by showing whether directors, officers and key employees who have proprietary information not available to the general public, are buying or selling the company's stock during the most recent six months.

Funds From Operations FFO
FFO is Funds from Operations and equal to a REIT's net income, excluding gains or losses from sales of property, plus real estate depreciation.

Investability Quotient (IQ)
The IQ is a measure of investment desirability. It serves as an indicator of potential medium-to-long term return and as a caution against downside risk. The measure takes into account variables such as technical indicators, earnings estimates, liquidity, financial ratios and selected S&P proprietary measures.

S&P's IQ Rationale:
Enterprise Products Partners

	Raw Score	Max Value
Proprietary S&P Measures	54	115
Technical Indicators	35	40
Liquidity/Volatility Measures	13	20
Quantitative Measures	24	75
IQ Total	**126**	**250**

Volatility
Rates the volatility of the stock's price over the past year.

Technical Evaluation
In researching the past market history of prices and trading volume for each company, S&P's computer models apply special technical methods and formulas to identify and project price trends for the stock.

Relative Strength Rank
Shows, on a scale of 1 to 99, how the stock has performed versus all other companies in S&P's universe on a rolling 13-week basis.

Global Industry Classification Standard (GICS)
An industry classification standard, developed by Standard & Poor's in collaboration with Morgan Stanley Capital International (MSCI). GICS is currently comprised of 10 Sectors, 24 Industry Groups, 68 Industries, and 154 Sub-Industries.

S&P Issuer Credit Rating
A Standard & Poor's Issuer Credit Rating is a current opinion of an obligor's overall financial capacity (its creditworthiness) to pay its financial obligations. This opinion focuses on the obligor's capacity and willingness to meet its financial commitments as they come due. It does not apply to any specific financial obligation, as it does not take into account the nature of and provisions of the obligation, its standing in bankruptcy or liquidation, statutory preferences, or the legality and enforceability of the obligation. In addition, it does not take into account the creditworthiness of the guarantors, insurers, or other forms of credit enhancement on the obligation. The Issuer Credit Rating is not a recommendation to purchase, sell, or hold a financial obligation issued by an obligor, as it does not comment on market price or suitability for a particular investor. Issuer Credit Ratings are based on current information furnished by obligors or obtained by Standard & Poor's from other sources it considers reliable. Standard & Poor's does not perform an audit in connection with any Issuer Credit Rating and may, on occasion, rely on unaudited financial information. Issuer Credit Ratings may be changed, suspended, or withdrawn as a result of changes in, or unavailability of, such information, or based on other circumstances.

Exchange Type
ASE - American Stock Exchange; NNM - Nasdaq National Market; NSC - Nasdaq SmallCap; NYSE - New York Stock Exchange; BB - OTC Bulletin Board; OT - Over-the-Counter; TO - Toronto Stock Exchange.

S&P Equity Research Services
Standard & Poor's Equity Research Services U.S. includes Standard & Poor's Investment Advisory Services LLC; Standard & Poor's Equity Research Services Europe includes Standard & Poor's LLC-London and Standard & Poor's AB (Sweden); Standard & Poor's Equity Research Services Asia includes Standard & Poor's LLC's offices in Hong Kong, Singapore and Tokyo, Standard & Poor's Malaysia Sdn Bhd, and Standard & Poor's Information Services (Australia) Pty Ltd.

Abbreviations Used in S&P Equity Research Reports
CAGR- Compound Annual Growth Rate; **CAPEX**- Capital Expenditures; **CY**- Calendar Year; **DCF**- Discounted Cash Flow; **EBIT**- Earnings Before Interest and Taxes; **EBITDA**- Earnings Before Interest, Taxes, Depreciation and Amortization; **EPS**- Earnings Per Share; **EV**- Enterprise Value; **FCF**- Free Cash Flow; **FFO**- Funds From Operations; **FY**- Fiscal Year; **P/E**- Price/Earnings ; **PEG Ratio**- P/E-to-Growth Ratio; **PV**- Present Value; **R&D**- Research & Development; **ROE**- Return on Equity; **ROI**- Return on Investment; **ROIC**- Return on Invested Capital; **ROA**- Return on Assets; **SG&A**- Selling, General & Administrative Expenses; **WACC**- Weighted Average Cost of Capital

Dividends on American Depository Receipts (ADRs) and American Depository Shares (ADSs) are net of taxes (paid in the country of origin).

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Enterprise Products Partners LP

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Required Disclosures

S&P Global STARS Distribution

In North America: As of December 31, 2008, research analysts at Standard & Poor's Equity Research Services U.S. have recommended 27.0% of issuers with buy recommendations, 61.2% with hold recommendations and 11.8% with sell recommendations.

In Europe: As of December 31, 2008, research analysts at Standard & Poor's Equity Research Services Europe have recommended 30.4% of issuers with buy recommendations, 45.3% with hold recommendations and 24.3% with sell recommendations.

In Asia: As of December 31, 2008, research analysts at Standard & Poor's Equity Research Services Asia have recommended 33.9% of issuers with buy recommendations, 54.4% with hold recommendations and 11.7% with sell recommendations.

Globally: As of December 31, 2008, research analysts at Standard & Poor's Equity Research Services globally have recommended 28.1% of issuers with buy recommendations, 58.3% with hold recommendations and 13.6% with sell recommendations.

★★★★★ **5-STARS (Strong Buy)**: Total return is expected to outperform the total return of a relevant benchmark, by a wide margin over the coming 12 months, with shares rising in price on an absolute basis.

★★★★☆ **4-STARS (Buy)**: Total return is expected to outperform the total return of a relevant benchmark over the coming 12 months, with shares rising in price on an absolute basis.

★★★☆☆ **3-STARS (Hold)**: Total return is expected to closely approximate the total return of a relevant benchmark over the coming 12 months, with shares generally rising in price on an absolute basis.

★★☆☆☆ **2-STARS (Sell)**: Total return is expected to underperform the total return of a relevant benchmark over the coming 12 months, and the share price not anticipated to show a gain.

★☆☆☆☆ **1-STARS (Strong Sell)**: Total return is expected to underperform the total return of a relevant benchmark by a wide margin over the coming 12 months, with shares falling in price on an absolute basis.

Relevant benchmarks: In North America the relevant benchmark is the S&P 500 Index, in Europe and in Asia, the relevant benchmarks are generally the S&P Europe 350 Index and the S&P Asia 50 Index.

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This investment analysis was prepared from the following sources: S&P MarketScope, S&P Compustat, S&P Industry Reports, I/B/E/S International, Inc.; Standard & Poor's, 55 Water St., New York, NY 10041.

Source: S&P.

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STANDARD &POOR'S

Kinder Morgan Energy Partners LP

S&P Recommendation STRONG BUY ★★★★★

Price
$50.58 (as of Feb 13, 2009)

12-Mo. Target Price
$59.00

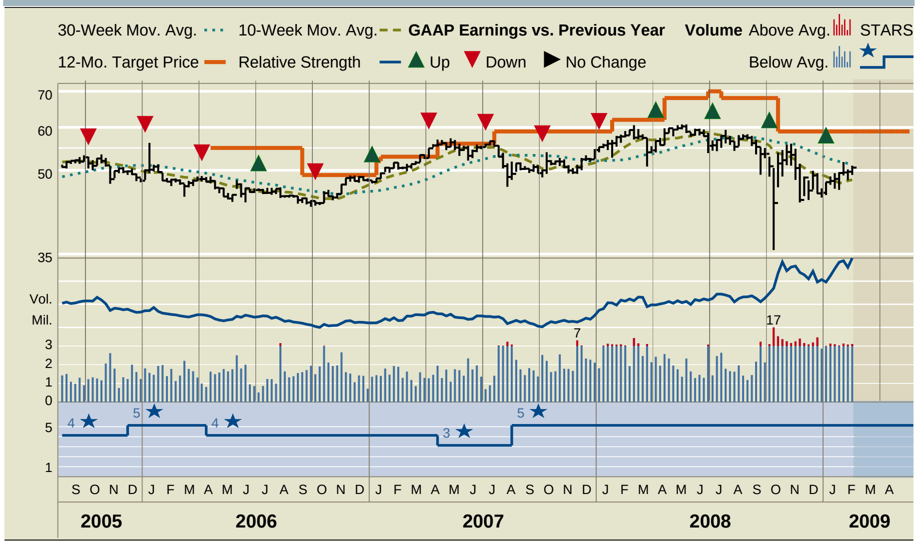
GICS Sector Energy
Sub-Industry Oil & Gas Storage & Transportation

Summary KMP is one of the largest pipeline master limited partnerships (MLPs) in the U.S.

Key Stock Statistics (Source S&P, Vickers, company reports)

52-Wk Range	$60.89– 35.59	S&P Oper. EPS 2009E	2.48	Market Capitalization(B)	$9.057	Beta	0.17
Trailing 12-Month EPS	$2.01	S&P Oper. EPS 2010E	2.65	Yield (%)	8.30	S&P 3-Yr. Proj. EPS CAGR(%)	15
Trailing 12-Month P/E	25.2	P/E on S&P Oper. EPS 2009E	20.4	Dividend Rate/Share	$4.20	S&P Credit Rating	BBB
$10K Invested 5 Yrs Ago	$15,364	Common Shares Outstg. (M)	179.1	Institutional Ownership (%)	23		

Price Performance



Options: CBOE, P

Analysis prepared by **Tanjila Shafi** on January 23, 2009, when the stock traded at **$ 48.96**.

Highlights

- We expect KMP's natural gas pipelines and terminal operations to be the main earnings drivers in 2009, benefiting from the first segment of the Rockies Express Pipeline now in service, terminal expansions in Houston, TX, Charleston, SC, Louisiana and Illinois, and acquisitions in Chicago and Vancouver. We expect product pipelines to benefit from the December 2007 completion of the East Line additional expansion project that increased pipeline capacity from Texas to Arizona and the increase in ownership to 100% (from 50%) of the Cochin NGL Pipeline from Canada to the U.S. We expect the impact of new projects to boost revenues by roughly 6% in 2009.
- With increased volumes from new projects, mainly in the natural gas pipeline segment, 2008 earnings before partnership interest rose more than 70%. We expect EBITDA to rise about 20% in 2009, to over $2.9 billion.
- KMP declared a cash distribution of $1.06 per unit for the 2008 fourth quarter, 14% above the 2007 fourth-quarter distribution of $0.92. For 2009, we forecast distributions of $4.20.

Investment Rationale/Risk

- We believe KMP's long-term growth profile is favorable, based on over $7 billion of investment planned for the next four years. The Rockies Express Pipeline and the Kinder Morgan Louisiana Pipeline should allow KMP to benefit from natural gas production in the Rockies and from the growing importance of LNG. In addition, KMP recently entered into a joint venture with Energy Transfer Partners (ETP: buy, $43) to build a new natural gas pipeline called the Midcontinent Express. We view positively the recent privatization of Kinder Morgan, Inc. (KMI). KMP should benefit from asset dropdowns from KMI, such as the recently announced acquisition of the Trans Mountain pipeline system.
- Risks to our recommendation and target price include sharply higher interest rates, and a decline in economic activity that reduces demand for energy commodities and leads to lower transportation volumes.
- Our 12-month target price of $59 is based on an above-peer target yield of 7.1% on estimated 2009 forward distributions of $4.20, which we believe is warranted given the partnership's diverse assets and dividend growth rate.

Qualitative Risk Assessment

LOW	MEDIUM	HIGH

Our risk assessment reflects our view of KMP's large and diversified asset portfolio, its stable, fee-based businesses, and its long-term record of increasing cash distributions.

Quantitative Evaluations

S&P Quality Ranking **NR**

D	C	B-	B	B+	A-	A	A+

Relative Strength Rank **STRONG**

77

LOWEST = 1 HIGHEST = 99

Revenue/Earnings Data

Revenue (Million $)

	1Q	2Q	3Q	4Q	Year
2008	2,720	3,496	3,233	2,292	11,740
2007	2,172	2,366	2,231	2,449	9,218
2006	2,392	2,196	2,273	2,093	8,955
2005	1,972	2,126	2,631	3,058	9,787
2004	1,822	1,957	2,015	2,139	7,933
2003	1,789	1,664	1,651	1,520	6,624

Earnings Per Share ($)

	1Q	2Q	3Q	4Q	Year
2008	0.63	0.65	0.48	0.26	2.01
2007	-1.27	0.34	0.21	-0.12	-0.82
2006	0.53	0.53	0.40	0.59	2.04
2005	0.54	0.50	0.57	-0.02	1.58
2004	0.52	0.51	0.59	0.59	2.22
2003	0.50	0.48	0.49	0.51	1.98

Fiscal year ended Dec. 31. Next earnings report expected: Mid April. EPS Estimates based on S&P Operating Earnings; historical GAAP earnings are as reported.

Dividend Data (Dates: mm/dd Payment Date: mm/dd/yy)

Amount ($)	Date Decl.	Ex-Div. Date	Stk. of Record	Payment Date
0.960	04/16	04/28	04/30	05/15/08
0.990	07/16	07/29	07/31	08/14/08
1.020	10/08	10/29	10/31	11/14/08
1.050	01/21	01/28	01/30	02/13/09

Dividends have been paid since 1992. Source: Company reports.

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Kinder Morgan Energy Partners LP

STANDARD &POOR'S

Business Summary January 23, 2009

CORPORATE OVERVIEW. Kinder Morgan Energy Partners, L.P. (KMP) is a publicly traded limited partnership formed in August 1992. The partnership is one of the largest publicly traded pipeline limited partnerships in the U.S. in terms of market capitalization. In total, it transports refined petroleum products and natural gas through over 25,000 miles of pipeline. In addition, it operates approximately 165 terminals handling refined products, coal, and other materials. Kinder Morgan, Inc. (KMI), one of the largest U.S. midstream energy companies, and its subsidiaries, owned a 13.9% interest in KMP at December 31, 2008. KMI was recently privatized. KMP's objective is to grow its portfolio of fee-based energy transportation and storage assets, while increasing the utilization of its existing assets. As a result, we believe it does not face significant risks relating to the short-term movement of commodity prices.

MARKET PROFILE. KMP, through its general and limited partner interests, has leveraged the resources of KMI to enable it to evolve into a leader in several core business segments, in our opinion. It is the largest independent U.S. owner and operator of pipelines transporting refined products as well as the largest independent operator of terminals. Its pipelines transport more than 2 million barrels per day of gasoline and other petroleum products and up to 7 billion cubic feet per day of natural gas. KMP's terminals handle over 90 million tons of coal and other dry bulk materials and have liquids storage capacity of about 70 million barrels for petroleum products and chemicals. In addition, KMP is a leading provider of carbon dioxide used for enhanced oil recovery projects in the United States. The natural gas segment was significantly expanded in November 2004 through the purchase of TransColorado Gas Transmission Co. from KMI for $284.5 million. TransColorado owns a 300-mile interstate pipeline extending from Colorado to New Mexico.

We believe KMP's size and financial resources have enabled it to distinguish itself from most other master limited partnerships (MLPs) through a balanced program of both acquisitions and internal expansion projects. During 2007, KMP spent $1.7 billion for additions to property, plant and equipment, including expansion and maintenance projects. KMP's total capital expansion program in 2007 was about $2.6 billion, and including acquisitions totaled $3.3 billion.

IMPACT OF MAJOR DEVELOPMENTS. Since 2005, KMP has laid the groundwork for three new capital projects that offer significant long-term growth potential, in our view. In total, we believe that KMP's $3.3 billion share of investments in these three projects will add at least $0.15 to $0.20 per unit in distributable cash flow by 2010.

In August 2005, KMP announced a 67.7%/33.3% joint venture with Sempra Energy to pursue the development of a new natural gas pipeline called the Rockies Express Pipeline, providing needed take-away capacity from producing areas in the Rocky Mountains. The planned 1,675-mile pipeline would originate in Wyoming and extend to eastern Ohio at an estimated total construction cost of $4.4 billion. The February 2006 acquisition of Entrega Gas Pipeline LLC added two connecting pipelines in Colorado and Wyoming. In February 2006, binding commitments were secured from shippers for all of the 1.8 billion cubic feet per day of capacity. In June 2006, ConocoPhillips joined the joint venture with a 24% share, reducing KMP's and Sempra Energy's shares to 51% and 25%, respectively. The project should be brought on line in segments and is expected to be completed by June 2009, subject to regulatory approvals. After completion, it will be one of the largest natural gas pipelines in North America.

In September 2006, KMP requested government approval for its proposed Louisiana Pipeline, which will provide approximately 3.2 billion cubic feet per day of natural gas take-away capacity from the new Cheniere Sabine Pass liquefied natural gas (LNG) terminal in Cameron Parish, LA. At a cost of $500 million, the pipeline would provide access to new supplies of imported LNG. The pipeline's capacity is fully subscribed with long-term commitments from Chevron and Total, and is expected to be completed in 2009.

In December 2007, KMP entered into a 50/50 joint venture with Energy Transfer Partners (ETP) to build a $1.25 billion natural gas pipeline called the Midcontinent Express, extending 500 miles from the Midcontinent Basin in Oklahoma to Alabama, with another connection through an ETP pipeline to the Barnett Shale natural gas region in northern Texas. The pipeline's 1.4 billion cubic feet of capacity is fully subscribed by multiple shippers. The expected completion date is February 2009.

FINANCIAL TRENDS. KMP has compiled what we view as an impressive history of increasing cash distributions to common unit holders. The distribution payout in 2008 was $4.02, 15.5% higher than the previous year's payout. Reflecting its diversified operations, KMP maintains coverage somewhat lower than the average MLP. We also note that as a relatively mature partnership, KMP pays 50% of incremental cash flow as incentives to the general partner, a higher level than most of its peers. KMI, through its ownership of the general partner and limited partnership units, received a total of 40% of all quarterly distributions in 2007. In comparison, Enterprise Products Partners, another large MLP, has capped its incentive distribution at a maximum of 25%.

Corporate Information

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Officers

Chrmn & CEO
R.D. Kinder

Chief Admin Officer
J.E. Street

Pres
C.P. Shaper

COO & EVP
S.J. Kean

Board Members
G. L. Hultquist
R. D. Kinder
C. B. Lawrence
C. P. Shaper
P. M. Waughtal

Domicile
Delaware

Founded
1992

Employees
0

Stockholders
190,660

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Kinder Morgan Energy Partners LP

Quantitative Evaluations

S&P Fair Value Rank 2-

1	2	3	4	5

LOWEST HIGHEST

Based on S&P's proprietary quantitative model, stocks are ranked from most overvalued (1) to most undervalued (5).

Fair Value Calculation $44.70

Analysis of the stock's current worth, based on S&P's proprietary quantitative model suggests that KMP is slightly overvalued by $5.88 or 11.6%.

Investability Quotient Percentile 70

LOWEST = 1 HIGHEST = 100

KMP scored higher than 70% of all companies for which an S&P Report is available.

Volatility

LOW	AVERAGE	HIGH

Technical Evaluation BULLISH

Since January, 2009, the technical indicators for KMP have been BULLISH.

Insider Activity NA

UNFAVORABLE	NEUTRAL	FAVORABLE

Expanded Ratio Analysis

	2008	2007	2006	2005
Price/Sales	NA	1.39	1.20	1.04
Price/EBITDA	NA	6.94	6.57	7.45
Price/Pretax Income	NA	25.87	10.71	12.04
P/E Ratio	NA	30.72	11.08	12.51
Avg. Diluted Shares Outstg (M)	NA	236.9	224.9	212.4

Figures based on calendar year-end price

Key Growth Rates and Averages

Past Growth Rate (%)	1 Year	3 Years	5 Years	9 Years
Sales	27.37	5.92	9.65	39.57
Net Income	NM	6.33	3.87	16.72
Ratio Analysis (Annual Avg.)				
Net Margin (%)	11.26	8.88	9.08	13.26
% LT Debt to Capitalization	NA	NA	61.86	53.90
Return on Equity (%)	25.57	41.12	33.49	26.28

Company Financials Fiscal Year Ended Dec. 31

Per Share Data ($)	2008	2007	2006	2005	2004	2003	2002	2001	2000	1999
Tangible Book Value	NA	13.54	12.93	11.80	15.28	14.64	13.65	15.65	13.12	14.40
Cash Flow	NA	3.99	6.16	5.47	5.69	4.92	4.53	3.79	2.86	2.36
Earnings	2.01	-0.82	2.04	1.58	2.22	1.98	1.96	1.56	1.33	1.32
S&P Core Earnings	NA	0.59	1.88	1.67	2.22	1.98	1.96	1.56	NA	NA
Dividends	NA	3.39	3.23	3.07	2.81	2.58	2.35	2.08	1.60	1.39
Payout Ratio	NA	NM	158%	194%	127%	130%	120%	133%	120%	105%
Prices:High	NA	57.35	56.22	55.20	49.12	49.95	38.89	39.65	28.88	22.81
Prices:Low	NA	46.61	42.80	42.77	37.65	33.51	23.90	25.19	18.19	16.50
P/E Ratio:High	NA	NM	28	35	22	25	20	25	22	17
P/E Ratio:Low	NA	NM	21	27	17	17	12	16	14	13
Income Statement Analysis (Million $)										
Revenue	11,740	9,218	8,955	9,787	7,933	6,624	4,237	2,947	816	429
Operating Income	NA	1,843	1,640	1,363	1,263	1,026	896	706	424	187
Depreciation	NA	530	414	350	289	219	172	142	82.6	46.5
Interest Expense	395	429	331	259	193	181	176	171	93.3	52.6
Pretax Income	1,350	494	1,006	844	861	720	633	470	300	172
Effective Tax Rate	1.02%	14.4%	1.89%	2.90%	2.29%	2.31%	2.41%	3.48%	4.64%	NM
Net Income	1,322	416	972	812	832	694	608	442	278	185
S&P Core Earnings	NA	751	937	832	831	693	608	442	NA	NA
Balance Sheet & Other Financial Data (Million $)										
Cash	63.0	127	14.0	12.1	Nil	23.3	41.1	62.8	59.3	40.1
Current Assets	NA	1,210	1,037	1,215	853	706	669	568	511	132
Total Assets	17,888	15,178	12,246	11,923	10,553	9,139	8,354	6,733	4,625	3,229
Current Liabilities	NA	2,558	2,886	1,809	1,181	804	813	963	1,099	319
Long Term Debt	NA	6,456	4,427	5,319	4,853	4,438	3,826	2,232	1,255	989
Common Equity	6,064	4,436	1,278	3,614	3,897	3,667	3,416	3,159	2,117	1,775
Total Capital	NA	11,148	5,831	9,046	8,851	8,183	7,315	5,494	3,431	2,812
Capital Expenditures	NA	1,692	397	863	747	577	542	295	126	82.7
Cash Flow	NA	946	1,386	1,162	1,120	913	780	584	361	231
Current Ratio	0.7	0.5	0.4	0.7	0.7	0.9	0.8	0.6	0.5	0.4
% Long Term Debt of Capitalization	56.6	59.0	75.9	58.8	54.8	54.2	52.3	40.6	36.6	35.2
% Net Income of Revenue	11.3	4.5	10.9	8.3	10.5	10.5	14.4	15.0	34.1	43.1
% Return on Assets	NA	3.0	8.0	7.2	8.4	7.9	8.1	7.8	7.1	6.9
% Return on Equity	25.6	9.9	87.9	21.6	22.5	19.5	18.5	16.8	14.3	11.8

Data as orig reptd.; bef. results of disc opers/spec. items. Per share data adj. for stk. divs.; EPS diluted. E-Estimated. NA-Not Available. NM-Not Meaningful. NR-Not Ranked. UR-Under Review.

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Kinder Morgan Energy Partners LP

STANDARD &POOR'S

Sub-Industry Outlook

Our fundamental outlook for the oil and gas storage and transportation sub-industry for the next 12 months is neutral. We expect fee-based pipeline and terminal operators to continue to expand earnings well in excess of anticipated real U.S. GDP growth in 2008 and 2009. As of January, S&P estimated a 1.1% increase in U.S. real GDP for 2008 and a 2.0% decline for 2009, compared to the 2.0% rise in 2007. However, we believe that investors are concerned that the tightening credit market may hinder MLPs from raising capital to fund their expansion projects. In response to the poor credit environment and weak economy, many MLPs plan to reduce their capital expansion budgets for 2009 to preserve capital and maintain their dividends.

We believe that 2009 will be a volatile year for tanker companies. Based on industry research group Bassoe, daily spot charter rates for VLCCs were $66,000 in the fourth quarter of 2008, below the $91,000 average in the third quarter. We expect tanker rates to continue to soften in 2009, due to the expected increase in the worldwide fleet, cuts in OPEC production, and the slowing global economy. The shipping industry suffered from increased piracy in 2008. If piracy is not curtailed, many shippers will re-route their vessels, leading to longer and more expensive trips, in our opinion.

As of early January 2009, the Energy Information Administration (EIA) estimated that U.S. petroleum consumption declined 5.7% in 2008 and would fall another 2.0% in 2009, after being little changed in 2007. The EIA also estimated that natural gas consumption would increase 0.7% in 2008 and decline 1.0% in 2009. Longer term, we think drivers for new transportation infrastructure include new import terminals for liquefied natural gas, transcontinental movement of gas from the Rockies to Northeast markets, and increased oil sands production in Alberta. In our view, an active merger and acquisition environment will also remain a principal investor focus. Current yields as of February 3, 2009, on our universe of MLPs averaged about 11.0%, above the benchmark 10-year Treasury note, which was yielding about 2.83% at that time.

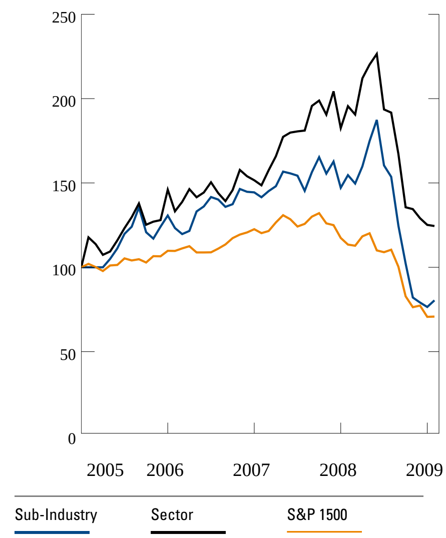
Year to date through February 2, the S&P Oil and Gas Storage and Transportation Index rose 1.1%, versus a 8.6% decline for the S&P 1500. In 2008, the S&P Oil and Gas Storage and Transportation Index was down 10.5%, versus a 38.2% decline for the S&P 1500. Our preference is for those issues with the potential to increase cash flow and dividend payouts over time.

--T. Shafi

Stock Performance

GICS Sector: Energy
Sub-Industry: Oil & Gas Storage & Transportation

Based on S&P 1500 Indexes
Month-end Price Performance as of 01/30/09



NOTE: All Sector & Sub-Industry information is based on the Global Industry Classification Standard (GICS)

Sub-Industry : Oil & Gas Storage & Transportation Peer Group*: Midstream Energy - Master Limited Partnership

Peer Group	Stock Symbol	Stk.Mkt. Cap. (Mil. $)	Recent Stock Price($)	52 Week High/Low($)	Beta	Yield (%)	P/E Ratio	Fair Value Calc.($)	Quality Ranking	S&P IQ %ile	Return on Revenue (%)	LTD to Cap (%)
Kinder Morgan Egy Ptnrs L.P.	**KMP**	**9,057**	**50.58**	**60.89/35.59**	**0.17**	**8.3**	**25**	**44.70**	**NR**	**70**	**11.3**	**56.6**
Buckeye Ptnrs L.P.	BPL	2,001	41.37	51.09/22.00	0.08	8.6	13	38.60	NR	70	29.9	43.3
Copano Energy L.L.C.	CPNO	799	16.53	39.75/8.80	1.45	13.9	14	NA	NR	23	5.5	41.3
Enbridge Energy Ptnrs L.P.	EEP	1,865	31.16	53.45/22.33	0.36	12.7	9	31.10	NR	50	3.0	53.8
Enterprise Products Partners	EPD	10,119	23.23	32.64/16.00	0.46	9.1	12	19.30	B+	87	3.2	51.3
Holly Energy Ptnrs L.P.	HEP	466	28.52	47.03/14.93	0.41	10.7	21	NA	NR	34	21.5	NA
Magellan Midstream Hldgs L.P.	MGG	1,034	16.51	25.96/11.28	0.39	8.7	12	NA	NR	60	7.1	NA
Magellan Midstream Partners L.P.	MMP	2,369	35.49	45.00/18.85	0.05	8.0	11	32.10	NR	91	28.6	NA
MarkWest Energy Ptnrs L.P.	MWE	672	11.87	38.50/6.55	0.62	21.6	14	NA	NR	78	2.6	47.5
NuStar Energy L.P.	NS	2,646	48.58	55.11/27.00	0.03	8.7	12	43.20	NR	94	5.3	NA
ONEOK Partners L.P.	OKS	2,561	47.06	64.87/35.61	0.45	9.2	8	41.90	NR	94	7.0	54.2
Plains All Amer Pipeline LP	PAA	4,912	39.96	50.96/23.25	0.51	8.8	15	36.10	NR	88	1.4	47.9
Sunoco Logistics Ptnrs LP	SXL	1,576	54.98	56.00/27.62	0.25	7.2	11	NA	NR	92	2.1	46.6
TC Pipelines L.P.	TCLP	882	25.29	37.29/18.11	0.75	11.2	9	27.10	NR	79	64.8	38.7
Teppco Ptnrs L.P.	TPP	2,510	24.01	38.61/16.90	0.03	12.1	15	16.50	NR	53	2.9	54.4

NA-Not Available NM-Not Meaningful NR-Not Rated. *For Peer Groups with more than 15 companies or stocks, selection of issues is based on market capitalization.

Source: S&P.

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Kinder Morgan Energy Partners LP

STANDARD &POOR'S

S&P Analyst Research Notes and other Company News

January 26, 2009
On January 21, 2009, Kinder Morgan Energy Partners LP board of directors has elected C. Berdon Lawrence as a director to fill the vacancy left by Edward O. Gaylord, who passed away on September 28, 2008. Mr. Lawrence is expected to be appointed to each board's audit committee, compensation committee and nominating and governance committee.

January 22, 2009
02:22 pm ET ... S&P MAINTAINS STRONG BUY OPINION ON LP UNITS OF KINDER MORGAN ENERGY PARTNERS (KMP 49.15*****): KMP reports Q4 earnings per unit of $0.26 vs. $0.50, lower than our $0.59 estimate and consensus of $0.54. The shortfall reflects lower-than-expected results at the company's products pipelines and CO2 businesses. We continue to believe that 2009 earnings will be driven by expansion projects, and we are maintaining our 2009 EPS estimate of $2.48. We are also maintaining our 12-month target price of $59, based an above-peer target yield of 7.1% on estimated 2009 forward distributions of $4.20. /T.Shafi

January 5, 2009
02:18 pm ET ... S&P MAINTAINS STRONG BUY OPINION ON LP UNITS OF KINDER MORGAN ENERGY PARTNERS (KMP 48.57*****): Ahead of KMP's Q4 results, we continue to forecast Q4 operating earnings per unit of $0.59. We expect earnings to be driven by expansion projects such as Rockies Express, and terminal acquisitions. Our earnings per unit estimate for '09 is $2.48. We have a favoragle long-term outlook for KMP, reflecting its diverse asset base and strong balance sheet. We are maintaining our 12-month target price of $59, based an above-peer target yield of 7.1% on estimated '09 forward distributions of $4.20. /T.Shafi

November 25, 2008
DOWN 2.29 to 45.75... KMP says it expects to declare cash distributions of $4.20 per unit for 2009. KMP also says it anticipates its business segments will generate approximately $2.85 billion in distributable cash flow in 2009, an increase of about $250 million over the 2008 budget. Morgan Keegan downgrades to market perform from outperform....

November 25, 2008
11:24 am ET ... KINDER MORGAN ENERGY PARTNERS, L.P. (KMP 46.1) DOWN 1.94, KINDER MORGAN (KMP) SETS '09 DISTRIBUTION GOAL. MORGAN KEEGAN DOWNGRADES... Analyst John Edwards tells salesforce he's downgrading KMP to market perform from outperform on KMP's distribution guidance. Notes KMP is still basing its 2008 distribution budget of $4.20/unit on $68/barrel, which he believes is optimistic in light of a $60 strip for 2009 and negative economic headwinds that are likely to pressure the outlook for commodity price recovery. Assumes $50-$60/barrel for WTI for 2009, and cuts his distribution growth view for KMP to -1.5% for 2009 from his former view of 7.6%./B.Egli

October 16, 2008
10:48 am ET ... S&P MAINTAINS STRONG BUY OPINION ON LP UNITS OF KINDER MORGAN ENERGY PARTNERS (KMP 48.07*****): KMP posts Q3 earnings per unit of $0.48 vs. $0.21, below our $0.60 estimate on lower results than we expected at its product pipelines business. The company increased its third quarter dividend by almost 16% to $1.02. We believe that the company's expansion projects will drive growth in 2009. But based on Q3 results, we are lowering our '08 earnings per unit estimate to $2.35 from $2.47. We are also reducing our 12-month target price to $59 from $68, based on an above-peer target yield of 6.9% on estimated 12-month forward distributions of $4.08. /T.Shafi

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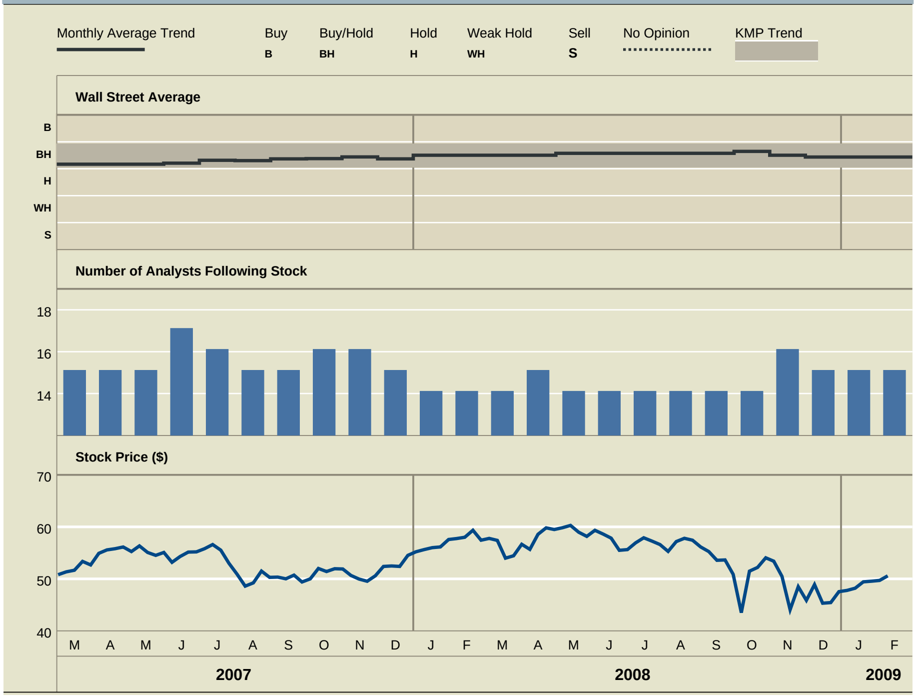
Kinder Morgan Energy Partners LP

STANDARD &POOR'S

Analysts' Recommendations



Of the total 15 companies following KMP, 15 analysts currently publish recommendations.

	No. of Ratings	% of Total	1 Mo. Prior	3 Mos. Prior
Buy	4	27	4	5
Buy/Hold	6	40	6	6
Hold	5	33	5	5
Weak Hold	0	0	0	0
Sell	0	0	0	0
No Opinion	0	0	0	0
Total	**15**	**100**	**15**	**16**

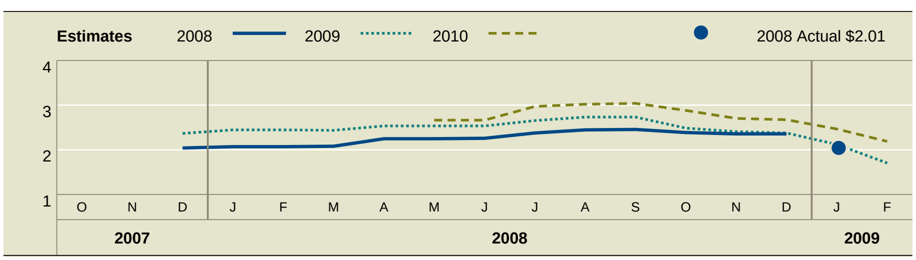
Wall Steet Consensus Opinion

BUY/HOLD

Companies Offering Coverage

Argus Research Corp.
Barclays Capital
Deutsche Bank
Goldman Sachs & Co.
JP Morgan Securities
Merrill Lynch Research
Morgan Stanley & Company
Morgan, Keegan & Company, Inc.
Oppenheimer
RBC Capital Markets (US)
Raymond James & Assoc, Inc.
Sanders Morris Harris
Smith Barney
UBS Warburg
Wachovia Securities

Wall Street Consensus Estimates



Fiscal Years	Avg Est.	High Est.	Low Est.	# of Est.	Est. P/E
2010	2.20	2.77	1.49	15	23.0
2009	1.71	2.69	1.05	15	29.6
2010 vs. 2009	▲ **29%**	▲ **3%**	▲ **42%**	**0%**	▼ **-22%**
Q1'10	0.54	0.58	0.47	4	93.7
Q1'09	0.36	0.58	0.16	13	NM
Q1'10 vs. Q1'09	▲ **50%**	**0%**	▲ **194%**	▼ **-69%**	**NM**

A company's earnings outlook plays a major part in any investment decision. Standard & Poor's organizes the earnings estimates of over 2,300 Wall Street analysts, and provides their consensus of earnings over the next two years. This graph shows the trend in analyst estimates over the past 15 months.

Wall Street Consensus vs. Performance

For fiscal year 2009, analysts estimate that KMP will earn $1.71. For fiscal year 2010, analysts estimate that KMP's earnings per share will grow by 29% to $2.20.

Source: S&P,I/B/E/S International, Inc.
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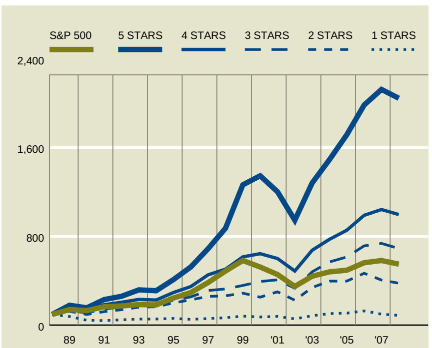
Kinder Morgan Energy Partners LP

Glossary

S&P STARS
Since January 1, 1987, Standard and Poor's Equity Research Services has ranked a universe of common stocks based on a given stock's potential for future performance. Under proprietary STARS (STock Appreciation Ranking System), S&P equity analysts rank stocks according to their individual forecast of a stock's future total return potential versus the expected total return of a relevant benchmark (e.g., a regional index (S&P Asia 50 Index, S&P Europe 350 Index or S&P 500 Index)), based on a 12-month time horizon. STARS was designed to meet the needs of investors looking to put their investment decisions in perspective.

STARS Average Annual Performance



S&P 12-Month Target Price
The S&P equity analyst's projection of the market price a given security will command 12 months hence, based on a combination of intrinsic, relative, and private market valuation metrics.

Investment Style Classification
Characterizes the stock as Growth or Value, and indicates its capitalization level. Growth is evaluated along three dimensions (earnings, sales and internal growth), while Value is evaluated along four dimensions (book-to-price, cash flow-to-price, dividend yield and sale-to-price). Growth stocks score higher than the market average on growth dimensions and lower on value dimensions. The reverse is true for Value stocks. Certain stocks are classified as Blend, indicating a mixture of growth and value characteristics and cannot be classified as purely growth or value.

Qualitative Risk Assessment
The S&P equity analyst's view of a given company's operational risk, or the risk of a firm's ability to continue as an ongoing concern. The Qualitative Risk Assessment is a relative ranking to the S&P U.S. STARS universe, and should be reflective of risk factors related to a company's operations, as opposed to risk and volatility measures associated with share prices.

Quantitative Evaluations
In contrast to our qualitative STARS recommendations, which are assigned by S&P analysts, the quantitative evaluations described below are derived from proprietary arithmetic models. These computer-driven evaluations may at times contradict an analyst's qualitative assessment of a stock. One primary reason for this is that different measures are used to determine each. For instance, when designating STARS, S&P analysts assess many factors that cannot be reflected in a model, such as risks and opportunities, management changes, recent competitive shifts, patent expiration, litigation risk, etc.

S&P Quality Ranking
Growth and stability of earnings and dividends are deemed key elements in establishing S&P's Quality Rankings for common stocks, which are designed to capsulize the nature of this record in a single symbol. It should be noted, however, that the process also takes into consideration certain adjustments and modifications deemed desirable in establishing such rankings. The final score for each stock is measured against a scoring matrix determined by analysis of the scores of a large and representative sample of stocks. The range of scores in the array of this sample has been aligned with the following ladder of rankings:

A+	Highest	B	Below Average
A	High	B-	Lower
A-	Above Average	C	Lowest
B+	Average	D	In Reorganization
NR	Not Ranked		

S&P Fair Value Rank
Using S&P's exclusive proprietary quantitative model, stocks are ranked in one of five groups, ranging from Group 5, listing the most undervalued stocks, to Group 1, the most overvalued issues. Group 5 stocks are expected to generally outperform all others. A positive (+) or negative (-) Timing Index is placed next to the Fair Value ranking to further aid the selection process.A stock with a (+) added to the Fair Value Rank simply means that this stock has a somewhat better chance to outperform other stocks with the same Fair Value Rank. A stock with a (-) has a somewhat lesser chance to outperform other stocks with the same Fair Value Rank. The Fair Value rankings imply the following: 5-Stock is significantly undervalued; 4-Stock is moderately undervalued; 3-Stock is fairly valued; 2-Stock is modestly overvalued; 1-Stock is significantly overvalued.

S&P Fair Value Calculation
The price at which a stock should trade at, according to S&P's proprietary quantitative model that incorporates both actual and estimated variables (as opposed to only actual variables in the case of S&P Quality Ranking). Relying heavily on a company's actual return on equity, the S&P Fair Value model places a value on a security based on placing a formula-derived price-to-book multiple on a company's consensus earnings per share estimate.

Insider Activity
Gives an insight as to insider sentiment by showing whether directors, officers and key employees who have proprietary information not available to the general public, are buying or selling the company's stock during the most recent six months.

Funds From Operations FFO
FFO is Funds from Operations and equal to a REIT's net income, excluding gains or losses from sales of property, plus real estate depreciation.

Investability Quotient (IQ)
The IQ is a measure of investment desirability. It serves as an indicator of potential medium-to-long term return and as a caution against downside risk. The measure takes into account variables such as technical indicators, earnings estimates, liquidity, financial ratios and selected S&P proprietary measures.

S&P's IQ Rationale:
Kinder Morgan Egy Ptnrs L.P.

	Raw Score	Max Value
Proprietary S&P Measures	25	115
Technical Indicators	36	40
Liquidity/Volatility Measures	16	20
Quantitative Measures	26	75
IQ Total	**103**	**250**

Volatility
Rates the volatility of the stock's price over the past year.

Technical Evaluation
In researching the past market history of prices and trading volume for each company, S&P's computer models apply special technical methods and formulas to identify and project price trends for the stock.

Relative Strength Rank
Shows, on a scale of 1 to 99, how the stock has performed versus all other companies in S&P's universe on a rolling 13-week basis.

Global Industry Classification Standard (GICS)
An industry classification standard, developed by Standard & Poor's in collaboration with Morgan Stanley Capital International (MSCI). GICS is currently comprised of 10 Sectors, 24 Industry Groups, 68 Industries, and 154 Sub-Industries.

S&P Issuer Credit Rating
A Standard & Poor's Issuer Credit Rating is a current opinion of an obligor's overall financial capacity (its creditworthiness) to pay its financial obligations. This opinion focuses on the obligor's capacity and willingness to meet its financial commitments as they come due. It does not apply to any specific financial obligation, as it does not take into account the nature of and provisions of the obligation, its standing in bankruptcy or liquidation, statutory preferences, or the legality and enforceability of the obligation. In addition, it does not take into account the creditworthiness of the guarantors, insurers, or other forms of credit enhancement on the obligation. The Issuer Credit Rating is not a recommendation to purchase, sell, or hold a financial obligation issued by an obligor, as it does not comment on market price or suitability for a particular investor. Issuer Credit Ratings are based on current information furnished by obligors or obtained by Standard & Poor's from other sources it considers reliable. Standard & Poor's does not perform an audit in connection with any Issuer Credit Rating and may, on occasion, rely on unaudited financial information. Issuer Credit Ratings may be changed, suspended, or withdrawn as a result of changes in, or unavailability of, such information, or based on other circumstances.

Exchange Type
ASE - American Stock Exchange; NNM - Nasdaq National Market; NSC - Nasdaq SmallCap; NYSE - New York Stock Exchange; BB - OTC Bulletin Board; OT - Over-the-Counter; TO - Toronto Stock Exchange.

S&P Equity Research Services
Standard & Poor's Equity Research Services U.S. includes Standard & Poor's Investment Advisory Services LLC; Standard & Poor's Equity Research Services Europe includes Standard & Poor's LLC-London and Standard & Poor's AB (Sweden); Standard & Poor's Equity Research Services Asia includes Standard & Poor's LLC's offices in Hong Kong, Singapore and Tokyo, Standard & Poor's Malaysia Sdn Bhd, and Standard & Poor's Information Services (Australia) Pty Ltd.

Abbreviations Used in S&P Equity Research Reports
CAGR- Compound Annual Growth Rate; **CAPEX**- Capital Expenditures; **CY**- Calendar Year; **DCF**- Discounted Cash Flow; **EBIT**- Earnings Before Interest and Taxes; **EBITDA**- Earnings Before Interest, Taxes, Depreciation and Amortization; **EPS**- Earnings Per Share; **EV**- Enterprise Value; **FCF**- Free Cash Flow; **FFO**- Funds From Operations; **FY**- Fiscal Year; **P/E**- Price/Earnings ; **PEG Ratio**- P/E-to-Growth Ratio; **PV**- Present Value; **R&D**- Research & Development; **ROE**- Return on Equity; **ROI**- Return on Investment; **ROIC**- Return on Invested Capital; **ROA**- Return on Assets; **SG&A**- Selling, General & Administrative Expenses; **WACC**- Weighted Average Cost of Capital

Dividends on American Depository Receipts (ADRs) and American Depository Shares (ADSs) are net of taxes (paid in the country of origin).

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Kinder Morgan Energy Partners LP

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In North America: As of December 31, 2008, research analysts at Standard & Poor's Equity Research Services U.S. have recommended 27.0% of issuers with buy recommendations, 61.2% with hold recommendations and 11.8% with sell recommendations.

In Europe: As of December 31, 2008, research analysts at Standard & Poor's Equity Research Services Europe have recommended 30.4% of issuers with buy recommendations, 45.3% with hold recommendations and 24.3% with sell recommendations.

In Asia: As of December 31, 2008, research analysts at Standard & Poor's Equity Research Services Asia have recommended 33.9% of issuers with buy recommendations, 54.4% with hold recommendations and 11.7% with sell recommendations.

Globally: As of December 31, 2008, research analysts at Standard & Poor's Equity Research Services globally have recommended 28.1% of issuers with buy recommendations, 58.3% with hold recommendations and 13.6% with sell recommendations.

★★★★★ **5-STARS (Strong Buy)**: Total return is expected to outperform the total return of a relevant benchmark, by a wide margin over the coming 12 months, with shares rising in price on an absolute basis.

★★★★☆ **4-STARS (Buy)**: Total return is expected to outperform the total return of a relevant benchmark over the coming 12 months, with shares rising in price on an absolute basis.

★★★☆☆ **3-STARS (Hold)**: Total return is expected to closely approximate the total return of a relevant benchmark over the coming 12 months, with shares generally rising in price on an absolute basis.

★★☆☆☆ **2-STARS (Sell)**: Total return is expected to underperform the total return of a relevant benchmark over the coming 12 months, and the share price not anticipated to show a gain.

★☆☆☆☆ **1-STARS (Strong Sell)**: Total return is expected to underperform the total return of a relevant benchmark by a wide margin over the coming 12 months, with shares falling in price on an absolute basis.

Relevant benchmarks: In North America the relevant benchmark is the S&P 500 Index, in Europe and in Asia, the relevant benchmarks are generally the S&P Europe 350 Index and the S&P Asia 50 Index.

For All Regions: All of the views expressed in this research report accurately reflect the research analyst's personal views regarding any and all of the subject securities or issuers. No part of analyst compensation was, is, or will be directly or indirectly, related to the specific recommendations or views expressed in this research report.

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Stock Report | February 17, 2009 | NYS Symbol: **OKS**

STANDARD &POOR'S

ONEOK Partners LP

S&P Recommendation BUY ★★★★★

Price
$46.02 (as of Feb 17, 2009)

12-Mo. Target Price
$62.00

UPDATE: PLEASE SEE THE ANALYST'S LATEST RESEARCH NOTE IN THE COMPANY NEWS SECTION

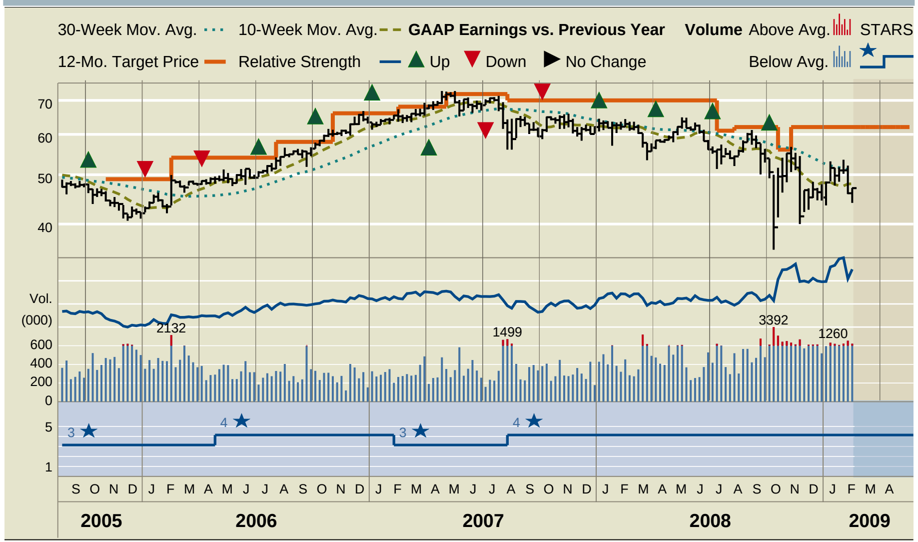
GICS Sector Energy
Sub-Industry Oil & Gas Storage & Transportation

Summary This partnership's principal asset is a 50% interest in Northern Border Pipeline Co., which transports natural gas from the U.S.-Canadian border to pipelines in the U.S.

Key Stock Statistics (Source S&P, Vickers, company reports)

52-Wk Range	$64.87– 35.61	S&P Oper. EPS 2008**E**	5.90	Market Capitalization(B)	$2.505	Beta	0.31
Trailing 12-Month EPS	$6.21	S&P Oper. EPS 2009**E**	4.85	Yield (%)	9.39	S&P 3-Yr. Proj. EPS CAGR(%)	6
Trailing 12-Month P/E	7.4	P/E on S&P Oper. EPS 2008**E**	7.8	Dividend Rate/Share	$4.32	S&P Credit Rating	BBB
$10K Invested 5 Yrs Ago	$16,770	Common Shares Outstg. (M)	90.9	Institutional Ownership (%)	21		

Price Performance



Options: P, Ph

Analysis prepared by **Tanjila Shafi** on January 15, 2009, when the stock traded at **$ 49.48**.

Highlights

- In 2009, we believe OKS will benefit from projects placed into service in 2008. A major driver for growth will come from the natural gas liquids (NGLs) Overland Pass Pipeline, which the partnership estimates will move 100,000 barrels per day by the end of the first quarter of 2009. We see OKS benefiting from contributions from projects that are expected to come on line in 2009. These include the 440-mile Arbuckle pipeline from Oklahoma to the Texas Gulf Coast, which is expected to be placed into service in the first quarter, and the 150-mile Piceance Lateral Pipeline, which is slated to come on line in the third quarter.
- The partnership expected $1.2 billion in capital investments in 2008, followed by capital expenditures projected at $350 million to $375 million in 2009.
- OKS announced a fourth-quarter cash distribution of $1.08 per share, up 5.4% from $1.025 in the fourth quarter of 2007. Our forecast for total cash distributions in 2009 is $4.32.

Investment Rationale/Risk

- We think the transactions with ONEOK (OKE: strong buy, $28) and TransCanada (TRP: hold, $27) have allowed OKS to redeploy its capital toward more promising interstate pipeline ventures such as gathering pipelines, processing operations and storage facilities. OKS is using surplus cash from these transactions to reduce debt and increase distributions. We believe OKS is well positioned for continued cash flow and distribution growth, given its organic growth projects.
- Risks to our recommendation and target price include events that would cause a persistent decline in natural gas prices; a sharper-than-expected rise in interest rates; and a decline in economic activity that reduces demand for energy commodities and therefore cuts transportation volumes.
- Our 12-month target price of $62 is based on a target yield of 7.0% and our 12-month forward distribution estimate of $4.32, a premium to peers that we believe is warranted given what we see as OKS's solid financial standing.

Qualitative Risk Assessment

LOW	**MEDIUM**	HIGH

Our risk assessment reflects OKS's exposure to cyclical swings in demand for commodity transportation, potential conflicts of interest between MLP (master limited partnership) unitholders and the general partners, and a tendency of MLPs to use excessive debt to fund dividend payments and other capital expenditures. These risks are offset by the maturity of the business and the strong visibility of revenues and cash flow.

Quantitative Evaluations

S&P Quality Ranking NR

D	C	B-	B	B+	A-	A	A+

Relative Strength Rank MODERATE

60

LOWEST = 1 HIGHEST = 99

Revenue/Earnings Data

Revenue (Million $)

	1Q	2Q	3Q	4Q	Year
2008	2,059	2,144	2,241	--	--
2007	1,169	1,375	1,410	1,877	5,832
2006	1,170	1,159	1,215	1,170	4,714
2005	160.4	149.4	183.0	185.7	678.6
2004	145.1	143.2	148.1	156.8	590.4
2003	138.2	134.4	138.0	145.4	555.9

Earnings Per Share ($)

	1Q	2Q	3Q	4Q	Year
2008	1.48	1.46	1.97	**E**0.99	**E**5.90
2007	1.00	0.97	0.98	1.27	4.21
2006	0.67	2.22	1.04	0.82	5.01
2005	0.68	0.54	0.99	0.71	2.92
2004	0.73	0.66	0.69	0.76	2.81
2003	0.70	0.56	-3.92	0.60	-2.16

Fiscal year ended Dec. 31. Next earnings report expected: Late February. EPS Estimates based on S&P Operating Earnings; historical GAAP earnings are as reported.

Dividend Data (Dates: mm/dd Payment Date: mm/dd/yy)

Amount ($)	Date Decl.	Ex-Div. Date	Stk. of Record	Payment Date
1.040	04/15	04/28	04/30	05/15/08
1.060	07/15	07/29	07/31	08/14/08
1.080	10/09	10/29	10/31	11/14/08
1.080	01/13	01/28	01/30	02/13/09

Dividends have been paid since 1994. Source: Company reports.

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ONEOK Partners LP

STANDARD &POOR'S

Business Summary January 15, 2009

CORPORATE OVERVIEW. ONEOK Partners, L.P. (formerly Northern Border Partners, L.P.) is a publicly traded partnership formed in 1993. OKS is a leading transporter of natural gas and natural gas liquids (NGLs) in the Mid-Continent area to market centers in the U.S. The company also owns a 50% equity interest in a major transporter of natural gas imported from Canada to the U.S. The partnership currently has four strategic business segments: Natural Gas Gathering and Processing (42% of 2007 operating income), Natural Gas Pipelines (25%), Natural Gas Liquids Gathering and Fractionation (25%), and Natural Gas Liquids Pipelines (8%).

The Natural Gas Gathering and Processing segment gathers and processes raw natural gas in the Mid-Continent region of Oklahoma and Kansas as well as the Rocky Mountain area of the U.S. and Canada. The Natural Gas Pipelines segment operates regulated natural gas transmission pipelines, natural gas storage facilities, and non-processable natural gas gathering facilities. The interstate pipeline assets are located primarily in the Midwest and Southwest. The Natural Gas Liquids Gathering and Fractionation segment gathers, treats, and fractionates NGLs produced by natural gas processing plants located in Oklahoma, Kansas and Texas, and stores and markets NGL products. The Natural Gas Liquids Pipelines segment operates regulated natural gas liquids gathering and distribution pipelines and associated above- and below-ground storage facilities.

OKS's general partner ONEOK, Inc. (OKE) owns the general partner of ONEOK Partners and 45.7% of the partnership. In April 2006, OKS purchased from OKE the gathering and processing, natural gas liquids and pipelines and storage segments for approximately $3 billion. In exchange, OKE received cash and limited partner units. In conjunction with this transaction, OKE sold a 20% interest in Northern Border Pipeline Company to TC Pipelines (TCLP: hold, $23). TCLP and OKS each now own a 50% interest in the pipeline, a 1,249-mile interstate pipeline system that transports natural gas from the Montana-Saskatchewan border to gas markets in the U.S. Midwest. The gas gathering and processing segment provides services for the gathering, treating, processing and compression of natural gas, and the fractionation of natural gas liquids for third parties and related field services. The partnership owns extensive natural gas gathering, processing and fractionation operations in Montana and North Dakota, and gas gathering operations in the Powder River Basin in Wyoming.

On July 2, 2007, OKS announced the acquisition of an interstate NGL and refined petroleum products pipeline system from Kinder Morgan Energy Partners for approximately $300 million. The system connects Bushton and Conway, KS, with Chicago, IL, and transports, stores and delivers a full range of NGL and refined products, directly linking the company's Mid-Continent supply and storage network to the upper Midwest. The acquisition is also OKS's first move into the refined petroleum products market.

MARKET PROFILE. Entry into the interstate pipeline business requires substantial upfront capital for construction, thus providing a formidable barrier to entry, in our view. Consequently, the transportation rates charged are regulated in the U.S. by the Federal Energy Regulatory Commission (FERC). Pipeline companies must formally present a detailed proposal for the construction and management of their transportation vehicles; FERC sets the transportation rates to allow for the recovery of costs plus a proscribed return on investment. In many cases, customers of a particular pipeline have very limited substitute transportation vehicles, resulting in a franchise for the pipeline company whose profitability is governed by the production growth inherent in the source end of the pipeline and the demographic growth of the other end.

While most northern master limited partnership (MLP) pipeline projects were originally financed to transport Canada's vast natural gas resources to the U.S., the increasing economic viability of its oil sands resources has led to an increasing proportion of Canadian natural gas resources remaining in the country to be utilized in oil sands development infrastructure. We believe Northern Border Pipeline Co. has been directly hurt by this development, as it is a substantial transportation vehicle for Canadian natural gas into the U.S. However, we think the transformational transactions with OKE and TransCanada (TRP) have significantly altered the impact of this trend, by de-emphasizing Canadian-U.S. traffic and adding significant gathering and processing assets in the Mid-Continent and the Rocky Mountains.

FINANCIAL TRENDS. OKE has underperformed other MLPs during the past few years, due to, in our opinion, the gradual loss of aggregate Canadian natural gas cross-border traffic with a shift toward domestic Canadian uses. We think the recent redeployment of capital toward domestic U.S. interstate pipeline assets and upstream natural gas infrastructure should lead to returns on invested capital in the low teens, up from the low single digits for most of the past decade.

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Chrmn & CEO
J.W. Gibson

SVP, CFO & Treas
C.L. Dinan

Pres & COO
J.C. Kneale

SVP & Chief Acctg Officer
C.A. Lawhorn

EVP & General Counsel
J.R. Barker

Board Members
C. L. Dinan
J. W. Gibson
J. C. Kneale
G. N. Petersen
G. B. Smith
G. Van Lunsen

Domicile
Delaware

Founded
1993

Stockholders
902

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STANDARD &POOR'S

ONEOK Partners LP

Quantitative Evaluations

S&P Fair Value Rank 2-

1	2	3	4	5
LOWEST				HIGHEST

Based on S&P's proprietary quantitative model, stocks are ranked from most overvalued (1) to most undervalued (5).

Fair Value Calculation $42.70

Analysis of the stock's current worth, based on S&P's proprietary quantitative model suggests that OKS is slightly overvalued by $3.32 or 7.2%.

Investability Quotient Percentile 94

LOWEST = 1 HIGHEST = 100

OKS scored higher than 94% of all companies for which an S&P Report is available.

Volatility LOW | AVERAGE | HIGH

Technical Evaluation BEARISH

Since February, 2009, the technical indicators for OKS have been BEARISH.

Insider Activity NA

UNFAVORABLE | NEUTRAL | FAVORABLE

Expanded Ratio Analysis

	2007	2006	2005	2004
Price/Sales	0.87	0.99	2.87	3.79
Price/EBITDA	9.36	9.02	5.68	6.58
Price/Pretax Income	12.17	9.83	9.84	11.40
P/E Ratio	12.45	10.50	13.30	15.86
Avg. Diluted Shares Outstg (M)	82.9	73.8	46.4	46.4

Figures based on calendar year-end price

Key Growth Rates and Averages

Past Growth Rate (%)	1 Year	3 Years	5 Years	9 Years
Sales	23.71	NM	71.49	37.68
Net Income	-8.41	53.71	NM	-2.53
Ratio Analysis (Annual Avg.)				
Net Margin (%)	6.99	12.68	9.07	15.06
% LT Debt to Capitalization	54.21	61.36	59.29	56.41
Return on Equity (%)	18.60	272.05	164.67	97.50

Company Financials Fiscal Year Ended Dec. 31

Per Share Data ($)	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998
Tangible Book Value	21.72	18.08	13.21	13.72	13.96	14.80	15.08	18.33	17.21	16.96
Cash Flow	6.20	7.69	3.16	4.90	4.59	4.44	4.29	4.63	4.62	3.80
Earnings	4.21	5.01	2.92	2.81	-2.16	2.44	2.15	2.50	2.70	2.27
S&P Core Earnings	4.12	4.07	2.92	2.81	-0.11	2.44	2.12	NA	NA	NA
Dividends	3.98	3.60	3.20	3.20	3.20	3.20	2.99	2.65	2.44	2.30
Payout Ratio	95%	72%	110%	114%	NM	131%	141%	106%	90%	101%
Prices:High	73.00	66.74	52.99	49.54	44.07	42.50	41.20	33.63	35.50	36.13
Prices:Low	56.00	42.00	40.60	35.70	35.98	29.30	30.25	23.00	21.63	31.13
P/E Ratio:High	17	13	18	18	NM	17	19	13	13	16
P/E Ratio:Low	13	8	14	13	NM	12	14	9	8	14
Income Statement Analysis (Million $)										
Revenue	5,832	4,714	679	590	556	496	461	340	319	218
Operating Income	542	518	343	340	-196	225	221	188	235	160
Depreciation	106	122	86.4	86.4	300	75.9	76.3	60.7	54.5	43.5
Interest Expense	153	133	86.9	76.9	79.0	82.9	89.9	81.9	67.8	49.9
Pretax Income	417	475	198	196	-42.2	156	131	115	117	98.1
Effective Tax Rate	2.12%	5.82%	2.93%	2.62%	NM	NM	NM	Nil	Nil	Nil
Net Income	408	445	147	141	-92.0	114	89.0	76.7	81.0	68.0
S&P Core Earnings	401	376	147	141	0.99	114	89.0	NA	NA	NA
Balance Sheet & Other Financial Data (Million $)										
Cash	3.21	21.1	43.1	34.0	35.9	34.7	16.8	35.4	22.9	41.0
Current Assets	987	807	138	117	114	105	78.7	81.7	60.6	69.6
Total Assets	6,112	5,035	2,528	2,511	2,571	2,725	2,687	2,083	1,863	1,826
Current Liabilities	1,262	785	111	89.3	107	176	441	129	238	81.4
Long Term Debt	2,605	2,020	1,353	1,325	1,408	1,336	1,071	1,127	848	974
Common Equity	2,195	2,189	13.4	789	801	944	915	572	515	507
Total Capital	4,806	4,214	1,651	2,412	2,452	2,523	2,236	1,948	1,614	1,734
Capital Expenditures	710	202	59.9	43.5	30.3	49.9	126	19.7	102	652
Cash Flow	514	567	147	227	208	190	165	137	135	112
Current Ratio	0.8	1.0	1.2	1.3	1.1	0.6	0.2	0.6	0.3	0.9
% Long Term Debt of Capitalization	54.2	47.9	81.9	54.9	57.4	53.0	47.9	57.9	52.6	56.2
% Net Income of Revenue	7.0	9.4	21.6	23.9	NM	22.9	19.3	22.6	25.4	31.3
% Return on Assets	7.3	11.8	5.8	5.5	NM	4.2	3.7	3.9	4.4	4.4
% Return on Equity	18.6	30.1	767.4	17.7	NM	12.2	12.0	14.1	15.8	13.5

Data as orig reptd.; bef. results of disc opers/spec. items. Per share data adj. for stk. divs.; EPS diluted. E-Estimated. NA-Not Available. NM-Not Meaningful. NR-Not Ranked. UR-Under Review.

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ONEOK Partners LP

STANDARD &POOR'S

Sub-Industry Outlook

Our fundamental outlook for the oil and gas storage and transportation sub-industry for the next 12 months is neutral. We expect fee-based pipeline and terminal operators to continue to expand earnings well in excess of anticipated real U.S. GDP growth in 2008 and 2009. As of January, S&P estimated a 1.1% increase in U.S. real GDP for 2008 and a 2.0% decline for 2009, compared to the 2.0% rise in 2007. However, we believe that investors are concerned that the tightening credit market may hinder MLPs from raising capital to fund their expansion projects. In response to the poor credit environment and weak economy, many MLPs plan to reduce their capital expansion budgets for 2009 to preserve capital and maintain their dividends.

We believe that 2009 will be a volatile year for tanker companies. Based on industry research group Bassoe, daily spot charter rates for VLCCs were $66,000 in the fourth quarter of 2008, below the $91,000 average in the third quarter. We expect tanker rates to continue to soften in 2009, due to the expected increase in the worldwide fleet, cuts in OPEC production, and the slowing global economy. The shipping industry suffered from increased piracy in 2008. If piracy is not curtailed, many shippers will re-route their vessels, leading to longer and more expensive trips, in our opinion.

As of early January 2009, the Energy Information Administration (EIA) estimated that U.S. petroleum consumption declined 5.7% in 2008 and would fall another 2.0% in 2009, after being little changed in 2007. The EIA also estimated that natural gas consumption would increase 0.7% in 2008 and decline 1.0% in 2009. Longer term, we think drivers for new transportation infrastructure include new import terminals for liquefied natural gas, transcontinental movement of gas from the Rockies to Northeast markets, and increased oil sands production in Alberta. In our view, an active merger and acquisition environment will also remain a principal investor focus. Current yields as of February 3, 2009, on our universe of MLPs averaged about 11.0%, above the benchmark 10-year Treasury note, which was yielding about 2.83% at that time.

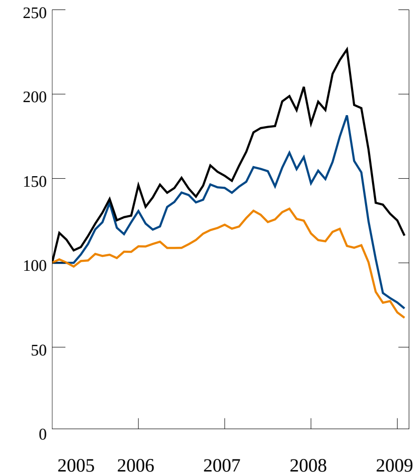
Year to date through February 2, the S&P Oil and Gas Storage and Transportation Index rose 1.1%, versus a 8.6% decline for the S&P 1500. In 2008, the S&P Oil and Gas Storage and Transportation Index was down 10.5%, versus a 38.2% decline for the S&P 1500. Our preference is for those issues with the potential to increase cash flow and dividend payouts over time.

--T. Shafi

Stock Performance

GICS Sector: Energy
Sub-Industry: Oil & Gas Storage & Transportation

Based on S&P 1500 Indexes
Month-end Price Performance as of 01/30/09



NOTE: All Sector & Sub-Industry information is based on the Global Industry Classification Standard (GICS)

Sub-Industry : Oil & Gas Storage & Transportation Peer Group*: Midstream Energy - Master Limited Partnership

Peer Group	Stock Symbol	Stk.Mkt. Cap. (Mil. $)	Recent Stock Price($)	52 Week High/Low($)	Beta	Yield (%)	P/E Ratio	Fair Value Calc.($)	Quality Ranking	S&P IQ %ile	Return on Revenue (%)	LTD to Cap (%)
ONEOK Partners L.P.	**OKS**	**2,561**	**47.06**	**64.87/35.61**	**0.31**	**9.2**	**8**	**42.70**	**NR**	**94**	**7.0**	**54.2**
Atlas Pipeline Ptnrs LP	APL	317	6.90	45.10/4.68	1.30	22.0	NM	NA	NR	20	NM	49.1
Buckeye Ptnrs L.P.	BPL	2,001	41.37	51.09/22.00	0.08	8.6	13	37.20	NR	70	29.9	43.3
Copano Energy L.L.C.	CPNO	799	16.53	39.75/8.80	1.03	13.9	14	NA	NR	23	5.5	41.3
Enbridge Energy Ptnrs L.P.	EEP	1,865	31.16	53.45/22.33	0.36	12.7	9	31.20	NR	50	3.0	53.8
Holly Energy Ptnrs L.P.	HEP	466	28.52	47.03/14.93	0.41	10.7	21	NA	NR	34	21.5	NA
Kinder Morgan Egy Ptnrs L.P.	KMP	9,057	50.58	60.89/35.59	0.10	8.3	25	46.20	NR	70	11.3	56.6
Magellan Midstream Hldgs L.P.	MGG	1,034	16.51	25.96/11.28	0.39	8.7	12	NA	NR	60	7.1	NA
Magellan Midstream Partners L.P.	MMP	2,369	35.49	45.00/18.85	0.05	8.0	11	33.50	NR	91	28.6	NA
MarkWest Energy Ptnrs L.P.	MWE	672	11.87	38.50/6.55	0.62	21.6	14	NA	NR	78	2.6	47.5
NuStar Energy L.P.	NS	2,646	48.58	55.11/27.00	0.03	8.7	12	43.90	NR	94	5.3	NA
Plains All Amer Pipeline LP	PAA	4,912	39.96	50.96/23.25	0.40	8.8	15	38.20	NR	88	1.4	47.9
Sunoco Logistics Ptnrs LP	SXL	1,576	54.98	56.00/27.62	0.25	7.2	11	NA	NR	92	2.1	46.6
TC Pipelines L.P.	TCLP	882	25.29	37.29/18.11	0.63	11.2	9	27.30	NR	79	64.8	38.7
Teppco Ptnrs L.P.	TPP	2,510	24.01	38.61/16.90	0.03	12.1	15	16.60	NR	53	2.9	54.4

NA-Not Available NM-Not Meaningful NR-Not Rated. *For Peer Groups with more than 15 companies or stocks, selection of issues is based on market capitalization.

Source: S&P.
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ONEOK Partners LP

S&P Analyst Research Notes and other Company News

February 17, 2009
02:28 pm ET ... S&P MAINTAINS STRONG BUY OPINION ON SHARES OF ONEOK INC (OKE 26.72*****): We are trimming our '09 EPS estimate by $0.60 to $2.67, as we expect weaker results from OKE 46%-owned subsidiary ONEOK Partners (OKS 46****), driven by substantially lower prices and lower volumes. We expect OKE's distribution segment and energy services segment to have higher earnings in '09, partly offsetting the weakness at OKS. For '08, we are keeping our EPS estimate for OKE at $3.05. We continue to see value in ownership of OKS and see benefits from its growth projects. We are cutting our 12-month target price on OKE by $3 to $34, based on the reduced '09 EPS outlook. /CMuir

February 6, 2009
DOWN 2.88 to 47.53... OKS reaffirms previously issued '08 EPS guidance, seeing earnings per unit within lower half of $5.95-$6.15 range. OKS also sees '08 distributable cash flow (DCF) of $625M-$655M. OKS's '09 earnings per unit is seen at $3.15-$3.75, with DCF at $490M-$550M.

January 14, 2009
12:01 pm ET ... S&P MAINTAINS BUY OPINION ON LP UNITS OF ONEOK PARTNERS (OKS 49.9****): Ahead of Q4 results, we are increasing our earnings per unit forecast to $0.99 from $0.69. We believe that the company will benefit from better-than-expected earnings in its natural gas liquids pipeline segment with the Overland Pass project coming online and wider natural gas liquids price differentials. However, we are trimming our '09 earnings per unit estimate to $4.85 from $5.00, reflecting macroeconomic headwinds. We maintain our target price at $62, based on a target yield of 7.0% from estimated 12-month forward distributions of $4.32. /T.Shafi

November 21, 2008
03:57 pm ET ... S&P MAINTAINS STRONG BUY OPINION ON SHARES OF ONEOK INC (OKE 25.75*****): Based on lower peer valuations, we are cutting our 12-month target price by $7 to $37. We continue to see value in OKE's stake in ONEOK Partners (OKS 41.54****), with large cash flows from limited and general partnership distributions. We see OKE's utility business as providing a stable operating base for the more volatile earnings from OKS. We keep our '08 and '09 EPS estimates at $3.05 and $3.27. We think the shares, currently trading at about 7.3X our '09 EPS estimate, a 40% discount to peers, are substantially undervalued. OKE's dividend is yielding 6.2%. /CMuir

November 6, 2008
03:29 pm ET ... S&P MAINTAINS BUY OPINION ON LP UNITS OF ONEOK PARTNERS (OKS 53.64****): OKS posts Q3 earnings per unit of $1.97 vs. $0.98, ahead of our $1.20 estimate. All of the company's segments performed better than expected. OKS' natural gas gathering and processing segment benefited from higher commodity prices and volumes, while the company's natural gas liquids businesses experienced increased volumes and wider price differentials. Based on Q3 results and company guidance, we increase our '08 earnings per unit est to $5.60 from $5.50. We also raise our target price to $62 from $56, on a target yield of 7.0% from estimated 12-month forward distributions. /T.Shafi

October 16, 2008
03:49 pm ET ... S&P MAINTAINS BUY OPINION ON LP UNITS OF ONEOK PARTNERS (OKS 47.91****): Ahead of Q3 results, we are maintaining our EPS forecast at $1.20 vs. year-ago $0.98. We believe OKS is well positioned to benefit from its $2 billion of internally generated growth projects. In addition, we expect the company to weather the upheaval in the credit markets better than many of its peers, given its solid financial condition. We are maintaining our '08 earnings per unit estimate at $5.50, but lower our target price to $56 from $62, based on a target yield of 7.7% from estimated 12-month forward distributions. /T.Shafi

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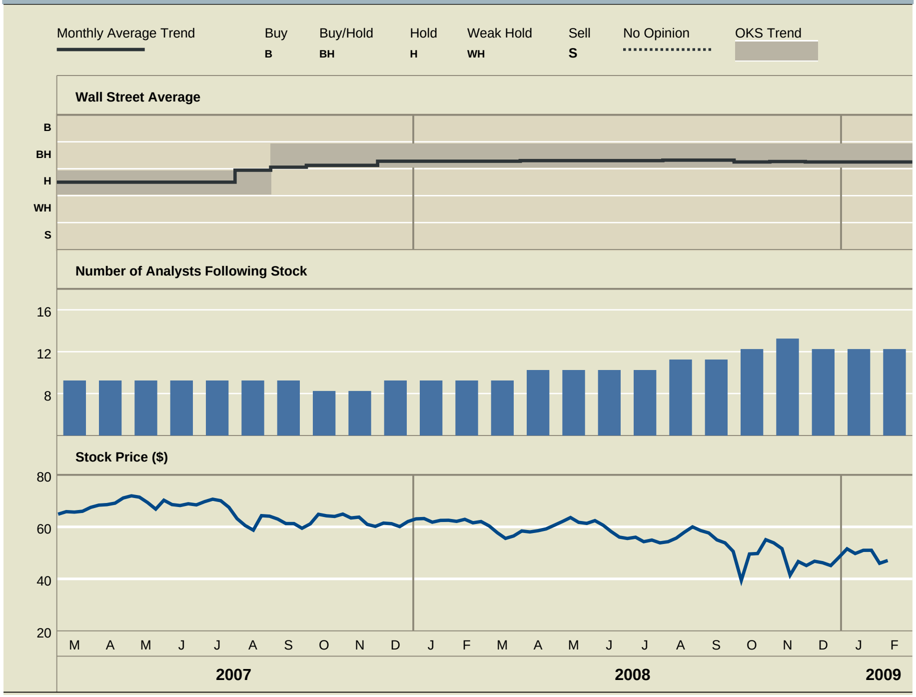
ONEOK Partners LP

STANDARD &POOR'S

Analysts' Recommendations



Of the total 13 companies following OKS, 13 analysts currently publish recommendations.

	No. of Ratings	% of Total	1 Mo. Prior	3 Mos. Prior
Buy	3	23	3	4
Buy/Hold	3	23	3	2
Hold	6	46	6	7
Weak Hold	0	0	0	0
Sell	0	0	0	0
No Opinion	1	8	1	1
Total	**13**	**100**	**13**	**14**

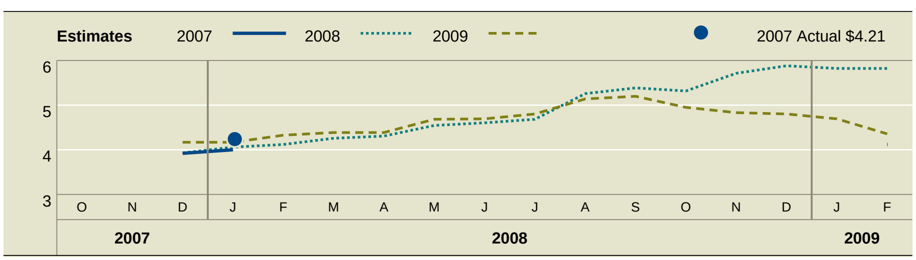
Wall Steet Consensus Opinion

BUY/HOLD

Companies Offering Coverage

Argus Research Corp.
Barclays Capital
Goldman Sachs & Co.
JP Morgan Securities
Merrill Lynch Research
Morgan Stanley & Company
Oppenheimer
Pickering Energy Partners, Inc.
RBC Capital Markets (US)
Sanders Morris Harris
Smith Barney
UBS Warburg
Wachovia Securities

Wall Street Consensus Estimates



Fiscal Years	Avg Est.	High Est.	Low Est.	# of Est.	Est. P/E
2009	4.37	5.99	3.19	13	10.5
2008	5.85	6.06	5.41	11	7.9
2009 vs. 2008	▼ -25%	▼ -1%	▼ -41%	▲ 18%	▲ 33%
Q4'09	1.08	1.26	0.80	7	42.6
Q4'08	1.07	1.21	0.84	11	43.0
Q4'09 vs. Q4'08	▲ 0.9%	▲ 4%	▼ -5%	▼ -36%	▼ -0.9%

A company's earnings outlook plays a major part in any investment decision. Standard & Poor's organizes the earnings estimates of over 2,300 Wall Street analysts, and provides their consensus of earnings over the next two years. This graph shows the trend in analyst estimates over the past 15 months.

Wall Street Consensus vs. Performance

For fiscal year 2008, analysts estimate that OKS will earn $5.85. For the 3rd quarter of fiscal year 2008, OKS announced earnings per share of $1.97, representing 34% of the total annual estimate. For fiscal year 2009, analysts estimate that OKS's earnings per share will decline by 25% to $4.37.

Source: S&P,I/B/E/S International, Inc.
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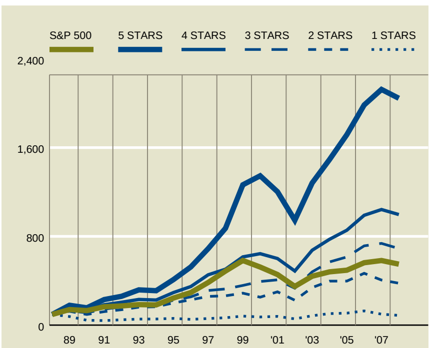
ONEOK Partners LP

Glossary

S&P STARS
Since January 1, 1987, Standard and Poor's Equity Research Services has ranked a universe of common stocks based on a given stock's potential for future performance. Under proprietary STARS (STock Appreciation Ranking System), S&P equity analysts rank stocks according to their individual forecast of a stock's future total return potential versus the expected total return of a relevant benchmark (e.g., a regional index (S&P Asia 50 Index, S&P Europe 350 Index or S&P 500 Index)), based on a 12-month time horizon. STARS was designed to meet the needs of investors looking to put their investment decisions in perspective.

STARS Average Annual Performance



S&P 12-Month Target Price
The S&P equity analyst's projection of the market price a given security will command 12 months hence, based on a combination of intrinsic, relative, and private market valuation metrics.

Investment Style Classification
Characterizes the stock as Growth or Value, and indicates its capitalization level. Growth is evaluated along three dimensions (earnings, sales and internal growth), while Value is evaluated along four dimensions (book-to-price, cash flow-to-price, dividend yield and sale-to-price). Growth stocks score higher than the market average on growth dimensions and lower on value dimensions. The reverse is true for Value stocks. Certain stocks are classified as Blend, indicating a mixture of growth and value characteristics and cannot be classified as purely growth or value.

Qualitative Risk Assessment
The S&P equity analyst's view of a given company's operational risk, or the risk of a firm's ability to continue as an ongoing concern. The Qualitative Risk Assessment is a relative ranking to the S&P U.S. STARS universe, and should be reflective of risk factors related to a company's operations, as opposed to risk and volatility measures associated with share prices.

Quantitative Evaluations
In contrast to our qualitative STARS recommendations, which are assigned by S&P analysts, the quantitative evaluations described below are derived from proprietary arithmetic models. These computer-driven evaluations may at times contradict an analyst's qualitative assessment of a stock. One primary reason for this is that different measures are used to determine each. For instance, when designating STARS, S&P analysts assess many factors that cannot be reflected in a model, such as risks and opportunities, management changes, recent competitive shifts, patent expiration, litigation risk, etc.

S&P Quality Ranking
Growth and stability of earnings and dividends are deemed key elements in establishing S&P's Quality Rankings for common stocks, which are designed to capsulize the nature of this record in a single symbol. It should be noted, however, that the process also takes into consideration certain adjustments and modifications deemed desirable in establishing such rankings. The final score for each stock is measured against a scoring matrix determined by analysis of the scores of a large and representative sample of stocks. The range of scores in the array of this sample has been aligned with the following ladder of rankings:

A+	Highest	B	Below Average
A	High	B-	Lower
A-	Above Average	C	Lowest
B+	Average	D	In Reorganization
NR	Not Ranked		

S&P Fair Value Rank
Using S&P's exclusive proprietary quantitative model, stocks are ranked in one of five groups, ranging from Group 5, listing the most undervalued stocks, to Group 1, the most overvalued issues. Group 5 stocks are expected to generally outperform all others. A positive (+) or negative (-) Timing Index is placed next to the Fair Value ranking to further aid the selection process.A stock with a (+) added to the Fair Value Rank simply means that this stock has a somewhat better chance to outperform other stocks with the same Fair Value Rank. A stock with a (-) has a somewhat lesser chance to outperform other stocks with the same Fair Value Rank. The Fair Value rankings imply the following: 5-Stock is significantly undervalued; 4-Stock is moderately undervalued; 3-Stock is fairly valued; 2-Stock is modestly overvalued; 1-Stock is significantly overvalued.

S&P Fair Value Calculation
The price at which a stock should trade at, according to S&P's proprietary quantitative model that incorporates both actual and estimated variables (as opposed to only actual variables in the case of S&P Quality Ranking). Relying heavily on a company's actual return on equity, the S&P Fair Value model places a value on a security based on placing a formula-derived price-to-book multiple on a company's consensus earnings per share estimate.

Insider Activity
Gives an insight as to insider sentiment by showing whether directors, officers and key employees who have proprietary information not available to the general public, are buying or selling the company's stock during the most recent six months.

Funds From Operations FFO
FFO is Funds from Operations and equal to a REIT's net income, excluding gains or losses from sales of property, plus real estate depreciation.

Investability Quotient (IQ)
The IQ is a measure of investment desirability. It serves as an indicator of potential medium-to-long term return and as a caution against downside risk. The measure takes into account variables such as technical indicators, earnings estimates, liquidity, financial ratios and selected S&P proprietary measures.

S&P's IQ Rationale:
ONEOK Partners L.P.

	Raw Score	Max Value
Proprietary S&P Measures	25	115
Technical Indicators	33	40
Liquidity/Volatility Measures	14	20
Quantitative Measures	71	75
IQ Total	**143**	**250**

Volatility
Rates the volatility of the stock's price over the past year.

Technical Evaluation
In researching the past market history of prices and trading volume for each company, S&P's computer models apply special technical methods and formulas to identify and project price trends for the stock.

Relative Strength Rank
Shows, on a scale of 1 to 99, how the stock has performed versus all other companies in S&P's universe on a rolling 13-week basis.

Global Industry Classification Standard (GICS)
An industry classification standard, developed by Standard & Poor's in collaboration with Morgan Stanley Capital International (MSCI). GICS is currently comprised of 10 Sectors, 24 Industry Groups, 68 Industries, and 154 Sub-Industries.

S&P Issuer Credit Rating
A Standard & Poor's Issuer Credit Rating is a current opinion of an obligor's overall financial capacity (its creditworthiness) to pay its financial obligations. This opinion focuses on the obligor's capacity and willingness to meet its financial commitments as they come due. It does not apply to any specific financial obligation, as it does not take into account the nature of and provisions of the obligation, its standing in bankruptcy or liquidation, statutory preferences, or the legality and enforceability of the obligation. In addition, it does not take into account the creditworthiness of the guarantors, insurers, or other forms of credit enhancement on the obligation. The Issuer Credit Rating is not a recommendation to purchase, sell, or hold a financial obligation issued by an obligor, as it does not comment on market price or suitability for a particular investor. Issuer Credit Ratings are based on current information furnished by obligors or obtained by Standard & Poor's from other sources it considers reliable. Standard & Poor's does not perform an audit in connection with any Issuer Credit Rating and may, on occasion, rely on unaudited financial information. Issuer Credit Ratings may be changed, suspended, or withdrawn as a result of changes in, or unavailability of, such information, or based on other circumstances.

Exchange Type
ASE - American Stock Exchange; NNM - Nasdaq National Market; NSC - Nasdaq SmallCap; NYSE - New York Stock Exchange; BB - OTC Bulletin Board; OT - Over-the-Counter; TO - Toronto Stock Exchange.

S&P Equity Research Services
Standard & Poor's Equity Research Services U.S. includes Standard & Poor's Investment Advisory Services LLC; Standard & Poor's Equity Research Services Europe includes Standard & Poor's LLC-London and Standard & Poor's AB (Sweden); Standard & Poor's Equity Research Services Asia includes Standard & Poor's LLC's offices in Hong Kong, Singapore and Tokyo, Standard & Poor's Malaysia Sdn Bhd, and Standard & Poor's Information Services (Australia) Pty Ltd.

Abbreviations Used in S&P Equity Research Reports
CAGR- Compound Annual Growth Rate; **CAPEX**- Capital Expenditures; **CY**- Calendar Year; **DCF**- Discounted Cash Flow; **EBIT**- Earnings Before Interest and Taxes; **EBITDA**- Earnings Before Interest, Taxes, Depreciation and Amortization; **EPS**- Earnings Per Share; **EV**- Enterprise Value; **FCF**- Free Cash Flow; **FFO**- Funds From Operations; **FY**- Fiscal Year; **P/E**- Price/Earnings ; **PEG Ratio**- P/E-to-Growth Ratio; **PV**- Present Value; **R&D**- Research & Development; **ROE**- Return on Equity; **ROI**- Return on Investment; **ROIC**- Return on Invested Capital; **ROA**- Return on Assets; **SG&A**- Selling, General & Administrative Expenses; **WACC**- Weighted Average Cost of Capital

Dividends on American Depository Receipts (ADRs) and American Depository Shares (ADSs) are net of taxes (paid in the country of origin).

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S&P Global STARS Distribution

In North America: As of December 31, 2008, research analysts at Standard & Poor's Equity Research Services U.S. have recommended 27.0% of issuers with buy recommendations, 61.2% with hold recommendations and 11.8% with sell recommendations.

In Europe: As of December 31, 2008, research analysts at Standard & Poor's Equity Research Services Europe have recommended 30.4% of issuers with buy recommendations, 45.3% with hold recommendations and 24.3% with sell recommendations.

In Asia: As of December 31, 2008, research analysts at Standard & Poor's Equity Research Services Asia have recommended 33.9% of issuers with buy recommendations, 54.4% with hold recommendations and 11.7% with sell recommendations.

Globally: As of December 31, 2008, research analysts at Standard & Poor's Equity Research Services globally have recommended 28.1% of issuers with buy recommendations, 58.3% with hold recommendations and 13.6% with sell recommendations.

★★★★★ **5-STARS (Strong Buy)**: Total return is expected to outperform the total return of a relevant benchmark, by a wide margin over the coming 12 months, with shares rising in price on an absolute basis.

★★★★☆ **4-STARS (Buy)**: Total return is expected to outperform the total return of a relevant benchmark over the coming 12 months, with shares rising in price on an absolute basis.

★★★☆☆ **3-STARS (Hold)**: Total return is expected to closely approximate the total return of a relevant benchmark over the coming 12 months, with shares generally rising in price on an absolute basis.

★★☆☆☆ **2-STARS (Sell)**: Total return is expected to underperform the total return of a relevant benchmark over the coming 12 months, and the share price not anticipated to show a gain.

★☆☆☆☆ **1-STARS (Strong Sell)**: Total return is expected to underperform the total return of a relevant benchmark by a wide margin over the coming 12 months, with shares falling in price on an absolute basis.

Relevant benchmarks: In North America the relevant benchmark is the S&P 500 Index, in Europe and in Asia, the relevant benchmarks are generally the S&P Europe 350 Index and the S&P Asia 50 Index.

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Southern Union Co

STANDARD &POOR'S

S&P Recommendation BUY ★★★★★	**Price** $13.79 (as of Feb 13, 2009)	**12-Mo. Target Price** $16.00	**Investment Style** Mid-Cap Growth

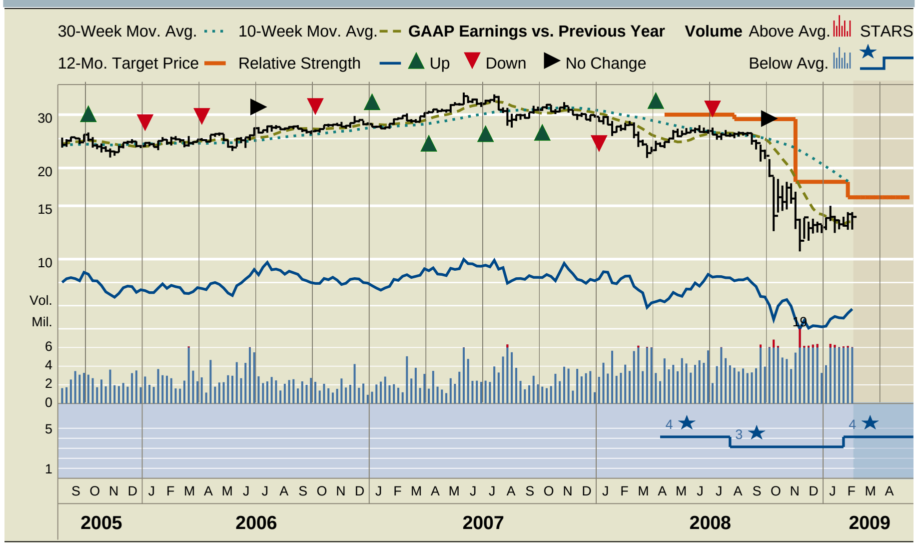
GICS Sector Energy
Sub-Industry Oil & Gas Storage & Transportation

Summary This energy company is engaged primarily in the transportation, storage, gathering, processing and distribution of natural gas.

Key Stock Statistics (Source S&P, Vickers, company reports)

52-Wk Range	**$28.62– 10.60**	S&P Oper. EPS 2008**E**	**1.80**	Market Capitalization(B)	**$1.710**	Beta	**1.28**
Trailing 12-Month EPS	**$1.69**	S&P Oper. EPS 2009**E**	**1.84**	Yield (%)	**4.35**	S&P 3-Yr. Proj. EPS CAGR(%)	**7**
Trailing 12-Month P/E	**8.2**	P/E on S&P Oper. EPS 2008**E**	**7.7**	Dividend Rate/Share	**$0.60**	S&P Credit Rating	**BBB-**
$10K Invested 5 Yrs Ago	**$8,491**	Common Shares Outstg. (M)	**124.0**	Institutional Ownership (%)	**74**		

Price Performance



Options: Ph

Analysis prepared by **Christopher B. Muir** on February 04, 2009, when the stock traded at **$ 13.76**.

Highlights

- We expect revenue growth of 19% for 2008, with SUG benefiting from strong growth at its gathering and processing unit, helped by higher volumes and prices, pipelines and storage segment revenues aided by higher volumes, and utility segment revenues strengthening on customer growth and higher rates. We see 2009 revenues falling 4.1% on lower commodity prices.
- We estimate operating margins of 15.1% in 2008 and 16.1% in 2009, after 16.3% in 2007. For 2008, we expect higher per-revenue cost of gas to be partly offset by lower per-revenue operating and maintenance expenses and slightly lower other non-fuel operating costs. We see pretax margins of 10.7% in 2008 and 11.4% in 2009, versus 11.7% in 2007, as we expect mostly unchanged interest expense offset by lower non-operating income.
- Assuming an effective tax rate of 31.6% and no share repurchases, we expect 2008 operating EPS of $1.80, up 2.9% from 2007's $1.75. We forecast 2009 EPS of $1.84, up 2.2%.

Investment Rationale/Risk

- We recently upgraded our recommendation on the shares to buy, from hold. We like SUG's growth strategy, as well as its investments in LNG, storage and pipelines. The company operates the largest of only a handful of LNG terminals in the U.S., and has contracted the capacity so that it gets paid whether or not the facility is used. While current plans to form an MLP from SUG's gathering and processing business are on hold, we think a recovery in the equity markets would lead the company to go forward with the process. In addition, SUG is interested in making more acquisitions.
- Risks to our recommendation and target price include milder-than-expected winter weather, low gas processing margins, and a sharp rise in interest rates.
- SUG's shares recently traded at 7.2X our 2009 EPS estimate, a 44% discount to its natural gas utility peers. Our 12-month target price of $16 is 8.7X our 2009 EPS estimate, or a 35% discount to our peer target. We believe this discount is appropriate given our expectations for EPS growth close to that of peers, offset by volatility in gas gathering segment results.

Qualitative Risk Assessment

LOW | **MEDIUM** | HIGH

Our risk assessment reflects our view of the company's steady cash flow from its regulated utility and pipeline operations, offset by its unregulated gathering and processing business and LNG regasification operations.

Quantitative Evaluations

S&P Quality Ranking **B**

D | C | B- | **B** | B+ | A- | A | A+

Relative Strength Rank **MODERATE**

62

LOWEST = 1 HIGHEST = 99

Revenue/Earnings Data

Revenue (Million $)

	1Q	2Q	3Q	4Q	Year
2008	952.7	733.1	657.3	--	--
2007	780.2	588.1	525.5	722.9	2,617
2006	547.2	552.4	564.4	676.2	2,340
2005	767.6	305.2	255.1	691.7	2,019
2004	231.4	507.1	235.0	560.0	794.0
2003	231.4	507.1	774.6	286.9	1,800

Earnings Per Share ($)

	1Q	2Q	3Q	4Q	Year
2008	0.64	0.30	0.34	**E**0.48	**E**1.80
2007	0.62	0.39	0.34	0.41	1.75
2006	0.60	0.10	0.06	0.92	1.70
2005	0.82	0.10	0.13	-1.00	0.03
2004	-0.05	0.42	-0.14	0.19	0.07
2003	-0.05	0.43	0.87	Nil	1.24

Fiscal year ended Dec. 31. Next earnings report expected: Early March. EPS Estimates based on S&P Operating Earnings; historical GAAP earnings are as reported.

Dividend Data (Dates: mm/dd Payment Date: mm/dd/yy)

Amount ($)	Date Decl.	Ex-Div. Date	Stk. of Record	Payment Date
0.150	03/18	03/26	03/28	04/11/08
0.150	06/16	06/25	06/27	07/11/08
0.150	09/12	09/24	09/26	10/10/08
0.150	12/16	12/23	12/26	01/09/09

Dividends have been paid since 2006. Source: Company reports.

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Southern Union Co

Business Summary February 04, 2009

CORPORATE OVERVIEW: Southern Union Company (SUG) engages in both regulated and unregulated businesses that include gathering, processing, transportation, storage and distribution of natural gas in the central and southern regions of the United States. The company operates in three segments: Transportation and Storage (25.2% of 2007 operating revenues), Gathering and Processing (46.7%), and Distribution (28.0%). The remainder of operating revenues comes from other and corporate operations.

CORPORATE STRATEGY: SUG continues to evaluate strategic options to maintain financial flexibility and identify organic growth opportunities. These options include possible acquisitions, partnership or joint venture opportunities with other investors, and/or exploring financial strategies. The company plans to utilize a master limited partnership structure for its gathering and processing business as a tax reduction strategy, but has placed the plans on hold until equity markets rebound. SUG says that it aims to maintain its creditworthiness to keep financial flexibility. The company said that it will use its financial flexibility and free cash flows for investing in growth projects, share repurchases, dividend increases and debt repayments.

MARKET PROFILE: The Transportation and Storage segment primarily operates interstate pipelines and various storage facilities along those pipelines. It also operates LNG terminals that provide regasification services. The 2.8 billion cubic feet per day (Bcfd) Panhandle Eastern Pipeline is 6,500 miles and connects the Panhandle region to major midwestern markets and pipelines to the Northeast. The 1.5 Bcfd Trunkline pipeline is 3,500 miles, connecting the Gulf Region to major midwestern markets and pipelines to the Northeast. Trunkline LNG is a liquefied natural gas import terminal in Lake Charles, LA, that has a peak capacity of 2.1 Bcfd and a sustainable capacity of 1.8 Bcfd. The LNG facility can store up to 9.0 Bcf equivalent of LNG. The 450 mile, 1.0 Bcfd Sea Robin Pipeline carries gas from deepwater Gulf cost supplies to the Gulf Coast, including the Trunkline pipeline. Storage facilities totaling 74.4 Bcf owned and 19.9 Bcf leased with a peak withdrawal capacity of 1.1 Bcfd serve the Panhandle Pipeline. The 50%-owned 5,000 mile, 2.3 Bcfd Florida Gas Transmission pipeline delivers gas collected in the Gulf Region throughout Florida.

Southern Union Gas Services (SUGS) engages in gas gathering and processing in Texas and New Mexico. It operates approximately 4,800 miles of natural gas and natural gas liquids gathering pipelines, primarily in the Permian Basin. SUGS has approximately 410 million cubic feet per day (MMcfd) of cryogenic processing capacity and an additional 470 MMcf/d high-pressure treating capacity.

The company's Distribution segment is primarily engaged in the local distribution of natural gas in Missouri, through Missouri Gas Energy, and Massachusetts, through New England Gas Company. The utilities serve over 550,000 residential, commercial and industrial customers through local distribution systems consisting of 9,068 miles of mains, 6,096 miles of service lines and 45 miles of transmission lines. Gas revenues from residential customers (68% of total revenues) increased 4.8% in 2007, from commercial customers (26%) decreased 1.5%, from industrial customers (1%) decreased 2.2%, and from gas transportation customers (2%) increased 3.4%. Remaining revenues were from other sources and unbilled revenues.

LEGAL/REGULATORY ISSUES. The utilities' natural gas rates and operations in Missouri and Massachusetts are regulated by the Missouri Public Service Commission (MPSC) and the Massachusetts Department of Telecommunications and Energy (MDTE), respectively. On April 3, 2007, Missouri Gas Energy implemented a $27.2 million rate increase. New England Gas implemented a $4.6 million rate increase on August 1, 2007. The company has a rate increase request pending at the Sea Robin pipeline.

FINANCIAL TRENDS. The company's cash and cash equivalents, excluding restricted cash, decreased from $5.8 million in 2006 to $5.7 million in 2007. Its capital expenditures rose from $277 million in 2005 to $333 million in 2006 and $689 million in 2007. We believe SUG has sufficient funds and access to the capital markets to meet its capital spending and debt requirements.

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Chrmn & CEO
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Pres & COO
E.D. Herschmann

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A. M. Lindemann
G. L. Lindemann
T. N. McCarter, III
G. Rountree, III
A. D. Scherer

Domicile
Delaware

Founded
1932

Employees
2,337

Stockholders
5,996

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Quantitative Evaluations

S&P Fair Value Rank 4-

1	2	3	4	5

LOWEST HIGHEST

Based on S&P's proprietary quantitative model, stocks are ranked from most overvalued (1) to most undervalued (5).

Fair Value Calculation $15.20 Analysis of the stock's current worth, based on S&P's proprietary quantitative model suggests that SUG is slightly undervalued by $1.41 or 10.2%.

Investability Quotient Percentile 72

LOWEST = 1 HIGHEST = 100

SUG scored higher than 72% of all companies for which an S&P Report is available.

Volatility LOW | **AVERAGE** | HIGH

Technical Evaluation NEUTRAL Since January, 2009, the technical indicators for SUG have been NEUTRAL.

Insider Activity UNFAVORABLE | **NEUTRAL** | FAVORABLE

Expanded Ratio Analysis

	2007	2006	2005	2004
Price/Sales	1.35	1.40	1.32	2.35
Price/EBITDA	5.79	6.47	NA	NA
Price/Pretax Income	10.94	10.05	29.11	10.17
P/E Ratio	15.49	15.11	NM	NM
Avg. Diluted Shares Outstg (M)	120.7	117.3	112.8	81.6

Figures based on calendar year-end price

Key Growth Rates and Averages

Past Growth Rate (%)	1 Year	3 Years	5 Years	9 Years
Sales	11.82	45.14	17.58	12.61
Net Income	5.36	NM	35.16	30.32
Ratio Analysis (Annual Avg.)				
Net Margin (%)	8.70	6.33	5.45	4.08
% LT Debt to Capitalization	57.30	55.51	57.52	59.50
Return on Equity (%)	11.10	7.64	8.33	6.43

Company Financials Fiscal Year Ended Dec. 31

Per Share Data ($)	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998
Tangible Book Value	15.72	14.47	10.39	6.61	4.86	3.46	NM	11.10	11.64	7.20
Earnings	1.75	1.70	0.03	0.07	1.24	0.67	0.30	0.86	0.19	0.24
S&P Core Earnings	1.79	1.70	1.67	1.33	0.18	0.31	0.05	NA	NA	NA
Dividends	0.45	0.40	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil
Payout Ratio	26%	24%	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil
Prices:High	35.50	29.76	26.29	23.78	23.78	16.97	16.61	20.67	21.89	17.32
Prices:Low	26.81	22.76	20.77	16.10	16.10	10.44	8.77	13.66	9.89	12.35
P/E Ratio:High	20	18	NM	NM	19	25	55	24	NM	73
P/E Ratio:Low	15	13	NM	NM	13	16	29	16	53	52
Income Statement Analysis (Million $)										
Revenue	2,617	2,340	2,019	794	1,800	1,189	1,291	1,933	832	605
Depreciation	178	152	126	63.4	119	60.6	77.2	87.0	55.1	41.9
Maintenance	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Fixed Charges Coverage	1.93	1.74	2.17	1.21	2.21	1.82	1.66	1.86	1.36	1.39
Construction Credits	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Effective Tax Rate	29.4%	33.5%	77.4%	48.5%	37.7%	35.7%	43.5%	41.4%	49.0%	40.5%
Net Income	229	217	20.7	14.8	114	43.7	19.6	56.7	11.1	10.4
S&P Core Earnings	216	200	190	108	11.9	20.3	3.46	NA	NA	NA
Balance Sheet & Other Financial Data (Million $)										
Gross Property	5,888	5,205	4,368	4,107	3,942	3,786	2,278	2,965	1,997	1,254
Capital Expenditures	617	348	280	178	226	79.7	93.3	124	100	73.1
Net Property	5,102	4,584	3,486	3,328	3,208	3,145	1,456	2,194	1,497	878
Capitalization:Long Term Debt	2,960	2,690	2,049	2,070	2,155	1,712	1,182	1,430	834	391
Capitalization:% Long Term Debt	57.3	56.7	52.5	58.0	63.1	65.0	63.3	66.4	53.1	49.3
Capitalization:Preferred	230	230	230	230	230	Nil	Nil	Nil	Nil	100
Capitalization:% Preferred	4.50	4.85	5.89	6.50	6.73	Nil	Nil	Nil	Nil	12.6
Capitalization:Common	1,976	1,820	1,624	1,268	1,032	920	685	722	736	301
Capitalization:% Common	38.2	38.4	41.6	35.5	30.2	35.0	36.7	33.6	46.9	38.0
Total Capital	5,859	5,357	4,300	3,933	3,766	2,915	1,868	2,355	1,754	792
% Operating Ratio	87.3	89.5	86.8	90.1	86.9	90.1	89.3	95.2	90.4	90.5
% Earned on Net Property	6.9	8.8	13.6	NA	13.4	9.4	10.5	7.2	7.6	7.5
% Return on Revenue	8.7	9.3	1.0	1.9	6.3	3.7	1.5	2.9	1.3	1.7
% Return on Invested Capital	5.9	8.8	8.0	NA	8.0	5.5	7.6	8.3	5.5	7.2
% Return on Common Equity	11.1	11.6	0.2	NA	10.4	5.4	2.8	7.8	2.1	3.5

Data as orig reptd.; bef. results of disc opers/spec. items. Per share data adj. for stk. divs.; EPS diluted. E-Estimated. NA-Not Available. NM-Not Meaningful. NR-Not Ranked. UR-Under Review.

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Sub-Industry Outlook

Our fundamental outlook for the oil and gas storage and transportation sub-industry for the next 12 months is neutral. We expect fee-based pipeline and terminal operators to continue to expand earnings well in excess of anticipated real U.S. GDP growth in 2008 and 2009. As of January, S&P estimated a 1.1% increase in U.S. real GDP for 2008 and a 2.0% decline for 2009, compared to the 2.0% rise in 2007. However, we believe that investors are concerned that the tightening credit market may hinder MLPs from raising capital to fund their expansion projects. In response to the poor credit environment and weak economy, many MLPs plan to reduce their capital expansion budgets for 2009 to preserve capital and maintain their dividends.

We believe that 2009 will be a volatile year for tanker companies. Based on industry research group Bassoe, daily spot charter rates for VLCCs were $66,000 in the fourth quarter of 2008, below the $91,000 average in the third quarter. We expect tanker rates to continue to soften in 2009, due to the expected increase in the worldwide fleet, cuts in OPEC production, and the slowing global economy. The shipping industry suffered from increased piracy in 2008. If piracy is not curtailed, many shippers will re-route their vessels, leading to longer and more expensive trips, in our opinion.

As of early January 2009, the Energy Information Administration (EIA) estimated that U.S. petroleum consumption declined 5.7% in 2008 and would fall another 2.0% in 2009, after being little changed in 2007. The EIA also estimated that natural gas consumption would increase 0.7% in 2008 and decline 1.0% in 2009. Longer term, we think drivers for new transportation infrastructure include new import terminals for liquefied natural gas, transcontinental movement of gas from the Rockies to Northeast markets, and increased oil sands production in Alberta. In our view, an active merger and acquisition environment will also remain a principal investor focus. Current yields as of February 3, 2009, on our universe of MLPs averaged about 11.0%, above the benchmark 10-year Treasury note, which was yielding about 2.83% at that time.

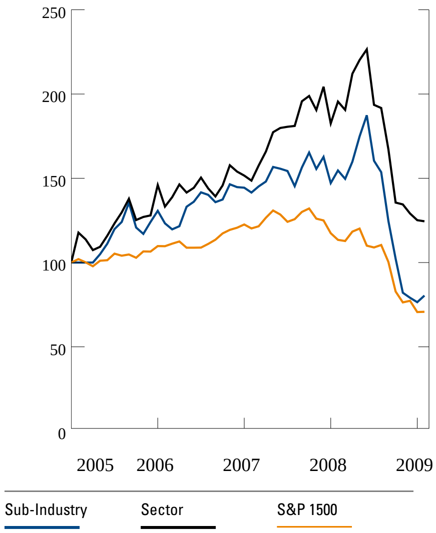
Year to date through February 2, the S&P Oil and Gas Storage and Transportation Index rose 1.1%, versus a 8.6% decline for the S&P 1500. In 2008, the S&P Oil and Gas Storage and Transportation Index was down 10.5%, versus a 38.2% decline for the S&P 1500. Our preference is for those issues with the potential to increase cash flow and dividend payouts over time.

--T. Shafi

Stock Performance

GICS Sector: Energy
Sub-Industry: Oil & Gas Storage & Transportation

Based on S&P 1500 Indexes
Month-end Price Performance as of 01/30/09



NOTE: All Sector & Sub-Industry information is based on the Global Industry Classification Standard (GICS)

Sub-Industry : Oil & Gas Storage & Transportation Peer Group*: Based on market capitalizations within GICS Sub-Industry

Peer Group	Stock Symbol	Stk.Mkt. Cap. (Mil. $)	Recent Stock Price($)	52 Week High/Low($)	Beta	Yield (%)	P/E Ratio	Fair Value Calc.($)	Quality Ranking	S&P IQ %ile	Return on Revenue (%)	LTD to Cap (%)
Southern Union	**SUG**	**1,710**	**13.79**	**28.62/10.60**	**1.28**	**4.4**	**8**	**15.20**	**B**	**72**	**8.7**	**50.5**
Buckeye GP Hldg L.P.	BGH	447	15.80	28.50/9.51	0.19	8.4	17	NA	NR	54	1.4	39.8
Cheniere Energy Ptnrs L.P.	CQP	1,010	6.24	17.57/3.65	NA	27.2	NM	NA	NR	52	NM	NA
DCP Midstream Ptnrs LP	DPM	272	11.02	37.89/5.26	1.01	21.8	NM	NA	NR	7	NM	76.3
Eagle Rock Energy Ptnrs L.P.	EROC	508	7.02	17.96/4.00	0.15	23.4	NM	NA	NR	66	NM	43.8
El Paso Pipeline Ptnrs L.P.	EPB	2,049	18.18	24.35/11.72	NA	6.3	23	NA	NR	38	60.0	53.8
Enterprise GP Holdings L.P.	EPE	2,801	22.74	33.76/14.50	0.38	8.3	17	NA	NR	85	0.4	51.0
Genesis Energy L.P.	GEL	479	12.15	22.33/6.42	1.57	10.9	NM	NA	NR	72	NM	10.9
Inergy Holding LP	NRGP	617	30.50	46.97/14.35	0.36	8.9	16	NA	NR	23	1.9	91.7
Kayne Anderson MLP Inv	KYN	820	19.50	31.45/11.07	0.91	10.3	NM	NA	NR	44	NA	NA
NuStar GP Hldgs LLC	NSH	839	19.73	28.41/12.16	0.48	8.7	13	NA	NR	78	NM	NA
Regency Energy Ptnrs LP	RGNC	912	11.23	31.18/4.92	0.98	15.9	13	10.60	NR	33	NM	50.3
Teekay Offshore Ptnrs L.P.	TOO	272	13.86	26.77/6.22	0.18	13.0	22	NA	NR	77	2.5	90.9
Williams Partners L.P.	WPZ	909	17.23	38.00/9.96	0.81	14.7	6	NA	NR	50	28.7	86.1
Williams Pipeline Ptnrs L.P.	WMZ	547	16.31	20.04/10.55	NA	7.8	4	NA	NR	74	NA	NA

NA-Not Available NM-Not Meaningful NR-Not Rated. *For Peer Groups with more than 15 companies or stocks, selection of issues is based on market capitalization.

Source: S&P.

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S&P Analyst Research Notes and other Company News

February 3, 2009
10:05 am ET ... RETRANSMIT - S&P UPGRADES OPINION ON SHARES OF SOUTHERN UNION TO BUY FROM HOLD (SUG 12.92****): Ahead of SUG's Q4 report, expected on 2/27, we maintain our EPS estimate of $0.48. We like SUG's growth strategy, as well as its investments in LNG, storage and pipelines. The company operates the largest of only a handful of LNG terminals in the U.S. and it has contracted the capacity so that it gets paid whether or not the facility is used. We are keeping our '08 EPS estimate at $1.80, but we are lowering our '09 forecast to $1.84 from $2.01 due to a reduction in our revenue projections. We are lowering our 12-month target price by $2 to $16. The stock is yielding 4.6%. /CMuir

February 3, 2009
09:24 am ET ... S&P UPGRADES OPINION ON SHARES OF SOUTHERN UNION TO BUY FROM HOLD (SUG 13.03****): Ahead of SUG's Q4 report, expected on 2/27, we maintain our EPS estimate of $0.48. We like SUG's growth strategy, as well as its investments in LNG, storage and pipelines. The company operates the largest of only a handful of LNG terminals in the U.S. and it has contracted the capacity so that it gets paid whether or not the facility is used. We are keeping our '08 EPS estimate at $1.80, but we are lowering our '09 forecast to $1.84 from $2.01 due to a reduction in our revenue projections. We are lowering our 12-month target price by $2 to $16. The stock is yielding 4.6%. /CMuir

November 20, 2008
SUG to be added to S&P MidCap 400 after the close of trading on Nov. 21, replacing AVIS BUDGET GROUP (CAR), which being removed due to its low market cap.

November 10, 2008
SUG posts $0.34 vs. $0.34 Q3 EPS (reported) on 25% revenue rise. Street was looking for $0.33. Reaffirms '08 adj. EPS guidance of $1.80-$1.90 (excl. items).

November 10, 2008
09:53 am ET ... S&P MAINTAINS HOLD OPINION ON SHARES OF SOUTHERN UNION (SUG 15.98***): Q3 recurring EPS of $0.36 vs. $0.34 misses our estimate by $0.06. Revenues were higher than we expected due to high commodity prices, and per-revenue depreciation expense was lower, but other per-revenue operating costs were higher than we expected. We continue to like SUG's growth strategy, as well as its investments in LNG, storage and pipelines, but we see EPS growth rates close to the peer average. We are lowering our '08 EPS estimate by $0.06 to $1.80, but keeping '09's at $2.01. We are cutting our 12-month target price to $18 due to lower peer valuations. /CMuir

November 3, 2008
03:49 pm ET ... S&P MAINTAINS HOLD OPINION ON SHARES OF SOUTHERN UNION (SUG 17.23***): We like SUG's growth strategy, as well as its investments in liquified natural gas, storage and pipelines. The company operates the largest of only a handful of LNG terminals in the U.S., and has contracted the capacity so that it gets paid whether or not the facility is used. We expect SUG on 11/10 to report Q3 EPS of $0.42, reflecting strong growth at its gathering & processing, and transportation & storage segments. We see operating margins slightly increasing from a year ago. We keep our '08 and '09 EPS estimates at $1.86 and $2.01 and our 12-month target price at $19. /C.Muir

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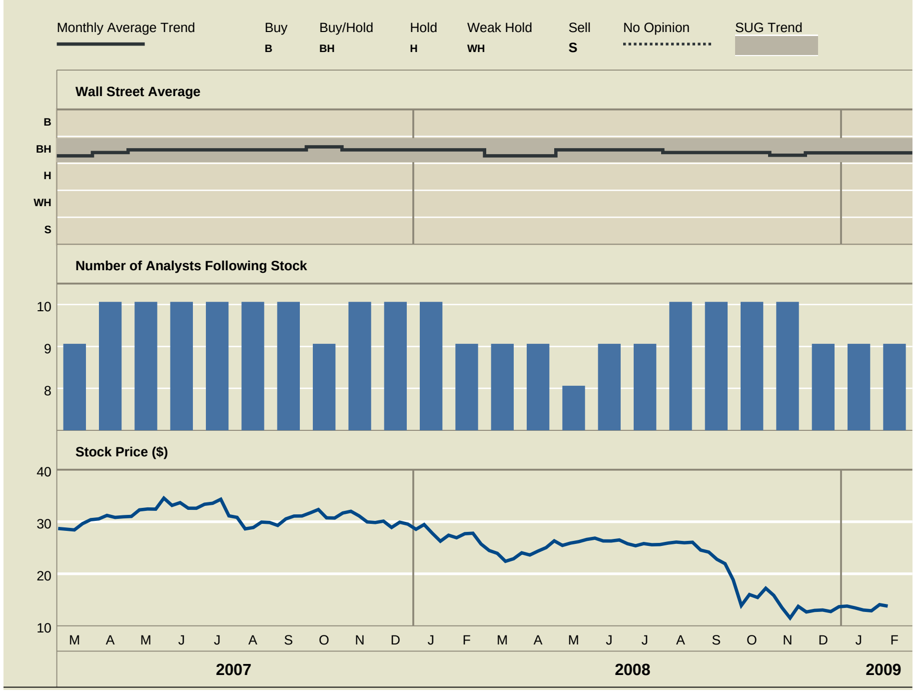
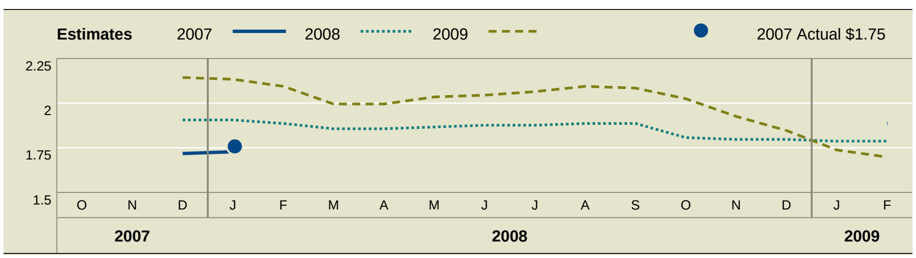
Analysts' Recommendations



Of the total 9 companies following SUG, 9 analysts currently publish recommendations.

	No. of Ratings	% of Total	1 Mo. Prior	3 Mos. Prior
Buy	3	33	3	3
Buy/Hold	3	33	3	3
Hold	2	22	2	3
Weak Hold	1	11	1	1
Sell	0	0	0	0
No Opinion	0	0	0	0
Total	**9**	**100**	**9**	**10**

Wall Street Consensus Estimates



Fiscal Years	Avg Est.	High Est.	Low Est.	# of Est.	Est. P/E
2009	1.70	1.99	1.41	9	8.1
2008	1.79	1.81	1.75	8	7.7
2009 vs. 2008	▼ -5%	▲ 10%	▼ -19%	▲ 13%	▲ 5%
Q4'09	0.47	0.41	0.35	3	29.3
Q4'08	0.44	0.54	0.36	9	31.3
Q4'09 vs. Q4'08	▲ 7%	▼ -24%	▼ -3%	▼ -67%	▼ -6%

A company's earnings outlook plays a major part in any investment decision. Standard & Poor's organizes the earnings estimates of over 2,300 Wall Street analysts, and provides their consensus of earnings over the next two years. This graph shows the trend in analyst estimates over the past 15 months.

Wall Steet Consensus Opinion

BUY/HOLD

Companies Offering Coverage

Barclays Capital
Calyon Securities (usa) Inc.
Harris Nesbitt
JP Morgan Securities
Pickering Energy Partners, Inc.
RBC Capital Markets (US)
Smith Barney
Stifel Nicolaus & Co.
Wachovia Securities

Wall Street Consensus vs. Performance

For fiscal year 2008, analysts estimate that SUG will earn $1.79. For the 3rd quarter of fiscal year 2008, SUG announced earnings per share of $0.34, representing 19% of the total annual estimate. For fiscal year 2009, analysts estimate that SUG's earnings per share will decline by 5% to $1.70.

Source: S&P,I/B/E/S International, Inc.

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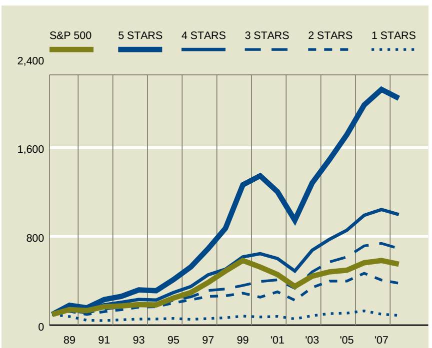
Glossary

S&P STARS
Since January 1, 1987, Standard and Poor's Equity Research Services has ranked a universe of common stocks based on a given stock's potential for future performance. Under proprietary STARS (STock Appreciation Ranking System), S&P equity analysts rank stocks according to their individual forecast of a stock's future total return potential versus the expected total return of a relevant benchmark (e.g., a regional index (S&P Asia 50 Index, S&P Europe 350 Index or S&P 500 Index)), based on a 12-month time horizon. STARS was designed to meet the needs of investors looking to put their investment decisions in perspective.

STARS Average Annual Performance



S&P 12-Month Target Price
The S&P equity analyst's projection of the market price a given security will command 12 months hence, based on a combination of intrinsic, relative, and private market valuation metrics.

Investment Style Classification
Characterizes the stock as Growth or Value, and indicates its capitalization level. Growth is evaluated along three dimensions (earnings, sales and internal growth), while Value is evaluated along four dimensions (book-to-price, cash flow-to-price, dividend yield and sale-to-price). Growth stocks score higher than the market average on growth dimensions and lower on value dimensions. The reverse is true for Value stocks. Certain stocks are classified as Blend, indicating a mixture of growth and value characteristics and cannot be classified as purely growth or value.

Qualitative Risk Assessment
The S&P equity analyst's view of a given company's operational risk, or the risk of a firm's ability to continue as an ongoing concern. The Qualitative Risk Assessment is a relative ranking to the S&P U.S. STARS universe, and should be reflective of risk factors related to a company's operations, as opposed to risk and volatility measures associated with share prices.

Quantitative Evaluations
In contrast to our qualitative STARS recommendations, which are assigned by S&P analysts, the quantitative evaluations described below are derived from proprietary arithmetic models. These computer-driven evaluations may at times contradict an analyst's qualitative assessment of a stock. One primary reason for this is that different measures are used to determine each. For instance, when designating STARS, S&P analysts assess many factors that cannot be reflected in a model, such as risks and opportunities, management changes, recent competitive shifts, patent expiration, litigation risk, etc.

S&P Quality Ranking
Growth and stability of earnings and dividends are deemed key elements in establishing S&P's Quality Rankings for common stocks, which are designed to capsulize the nature of this record in a single symbol. It should be noted, however, that the process also takes into consideration certain adjustments and modifications deemed desirable in establishing such rankings. The final score for each stock is measured against a scoring matrix determined by analysis of the scores of a large and representative sample of stocks. The range of scores in the array of this sample has been aligned with the following ladder of rankings:

A+	Highest	B	Below Average
A	High	B-	Lower
A-	Above Average	C	Lowest
B+	Average	D	In Reorganization
NR	Not Ranked		

S&P Fair Value Rank
Using S&P's exclusive proprietary quantitative model, stocks are ranked in one of five groups, ranging from Group 5, listing the most undervalued stocks, to Group 1, the most overvalued issues. Group 5 stocks are expected to generally outperform all others. A positive (+) or negative (-) Timing Index is placed next to the Fair Value ranking to further aid the selection process.A stock with a (+) added to the Fair Value Rank simply means that this stock has a somewhat better chance to outperform other stocks with the same Fair Value Rank. A stock with a (-) has a somewhat lesser chance to outperform other stocks with the same Fair Value Rank. The Fair Value rankings imply the following: 5-Stock is significantly undervalued; 4-Stock is moderately undervalued; 3-Stock is fairly valued; 2-Stock is modestly overvalued; 1-Stock is significantly overvalued.

S&P Fair Value Calculation
The price at which a stock should trade at, according to S&P's proprietary quantitative model that incorporates both actual and estimated variables (as opposed to only actual variables in the case of S&P Quality Ranking). Relying heavily on a company's actual return on equity, the S&P Fair Value model places a value on a security based on placing a formula-derived price-to-book multiple on a company's consensus earnings per share estimate.

Insider Activity
Gives an insight as to insider sentiment by showing whether directors, officers and key employees who have proprietary information not available to the general public, are buying or selling the company's stock during the most recent six months.

Funds From Operations FFO
FFO is Funds from Operations and equal to a REIT's net income, excluding gains or losses from sales of property, plus real estate depreciation.

Investability Quotient (IQ)
The IQ is a measure of investment desirability. It serves as an indicator of potential medium-to-long term return and as a caution against downside risk. The measure takes into account variables such as technical indicators, earnings estimates, liquidity, financial ratios and selected S&P proprietary measures.

S&P's IQ Rationale:
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	Raw Score	Max Value
Proprietary S&P Measures	54	115
Technical Indicators	29	40
Liquidity/Volatility Measures	16	20
Quantitative Measures	7	75
IQ Total	**106**	**250**

Volatility
Rates the volatility of the stock's price over the past year.

Technical Evaluation
In researching the past market history of prices and trading volume for each company, S&P's computer models apply special technical methods and formulas to identify and project price trends for the stock.

Relative Strength Rank
Shows, on a scale of 1 to 99, how the stock has performed versus all other companies in S&P's universe on a rolling 13-week basis.

Global Industry Classification Standard (GICS)
An industry classification standard, developed by Standard & Poor's in collaboration with Morgan Stanley Capital International (MSCI). GICS is currently comprised of 10 Sectors, 24 Industry Groups, 68 Industries, and 154 Sub-Industries.

S&P Issuer Credit Rating
A Standard & Poor's Issuer Credit Rating is a current opinion of an obligor's overall financial capacity (its creditworthiness) to pay its financial obligations. This opinion focuses on the obligor's capacity and willingness to meet its financial commitments as they come due. It does not apply to any specific financial obligation, as it does not take into account the nature of and provisions of the obligation, its standing in bankruptcy or liquidation, statutory preferences, or the legality and enforceability of the obligation. In addition, it does not take into account the creditworthiness of the guarantors, insurers, or other forms of credit enhancement on the obligation. The Issuer Credit Rating is not a recommendation to purchase, sell, or hold a financial obligation issued by an obligor, as it does not comment on market price or suitability for a particular investor. Issuer Credit Ratings are based on current information furnished by obligors or obtained by Standard & Poor's from other sources it considers reliable. Standard & Poor's does not perform an audit in connection with any Issuer Credit Rating and may, on occasion, rely on unaudited financial information. Issuer Credit Ratings may be changed, suspended, or withdrawn as a result of changes in, or unavailability of, such information, or based on other circumstances.

Exchange Type
ASE - American Stock Exchange; NNM - Nasdaq National Market; NSC - Nasdaq SmallCap; NYSE - New York Stock Exchange; BB - OTC Bulletin Board; OT - Over-the-Counter; TO - Toronto Stock Exchange.

S&P Equity Research Services
Standard & Poor's Equity Research Services U.S. includes Standard & Poor's Investment Advisory Services LLC; Standard & Poor's Equity Research Services Europe includes Standard & Poor's LLC-London and Standard & Poor's AB (Sweden); Standard & Poor's Equity Research Services Asia includes Standard & Poor's LLC's offices in Hong Kong, Singapore and Tokyo, Standard & Poor's Malaysia Sdn Bhd, and Standard & Poor's Information Services (Australia) Pty Ltd.

Abbreviations Used in S&P Equity Research Reports
CAGR- Compound Annual Growth Rate; **CAPEX**- Capital Expenditures; **CY**- Calendar Year; **DCF**- Discounted Cash Flow; **EBIT**- Earnings Before Interest and Taxes; **EBITDA**- Earnings Before Interest, Taxes, Depreciation and Amortization; **EPS**- Earnings Per Share; **EV**- Enterprise Value; **FCF**- Free Cash Flow; **FFO**- Funds From Operations; **FY**- Fiscal Year; **P/E**- Price/Earnings ; **PEG Ratio**- P/E-to-Growth Ratio; **PV**- Present Value; **R&D**- Research & Development; **ROE**- Return on Equity; **ROI**- Return on Investment; **ROIC**- Return on Invested Capital; **ROA**- Return on Assets; **SG&A**- Selling, General & Administrative Expenses; **WACC**- Weighted Average Cost of Capital

Dividends on American Depository Receipts (ADRs) and American Depository Shares (ADSs) are net of taxes (paid in the country of origin).

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S&P Global STARS Distribution

In North America: As of December 31, 2008, research analysts at Standard & Poor's Equity Research Services U.S. have recommended 27.0% of issuers with buy recommendations, 61.2% with hold recommendations and 11.8% with sell recommendations.

In Europe: As of December 31, 2008, research analysts at Standard & Poor's Equity Research Services Europe have recommended 30.4% of issuers with buy recommendations, 45.3% with hold recommendations and 24.3% with sell recommendations.

In Asia: As of December 31, 2008, research analysts at Standard & Poor's Equity Research Services Asia have recommended 33.9% of issuers with buy recommendations, 54.4% with hold recommendations and 11.7% with sell recommendations.

Globally: As of December 31, 2008, research analysts at Standard & Poor's Equity Research Services globally have recommended 28.1% of issuers with buy recommendations, 58.3% with hold recommendations and 13.6% with sell recommendations.

★★★★★ **5-STARS (Strong Buy)**: Total return is expected to outperform the total return of a relevant benchmark, by a wide margin over the coming 12 months, with shares rising in price on an absolute basis.

★★★★☆ **4-STARS (Buy)**: Total return is expected to outperform the total return of a relevant benchmark over the coming 12 months, with shares rising in price on an absolute basis.

★★★☆☆ **3-STARS (Hold)**: Total return is expected to closely approximate the total return of a relevant benchmark over the coming 12 months, with shares generally rising in price on an absolute basis.

★★☆☆☆ **2-STARS (Sell)**: Total return is expected to underperform the total return of a relevant benchmark over the coming 12 months, and the share price not anticipated to show a gain.

★☆☆☆☆ **1-STARS (Strong Sell)**: Total return is expected to underperform the total return of a relevant benchmark by a wide margin over the coming 12 months, with shares falling in price on an absolute basis.

Relevant benchmarks: In North America the relevant benchmark is the S&P 500 Index, in Europe and in Asia, the relevant benchmarks are generally the S&P Europe 350 Index and the S&P Asia 50 Index.

For All Regions: All of the views expressed in this research report accurately reflect the research analyst's personal views regarding any and all of the subject securities or issuers. No part of analyst compensation was, is, or will be directly or indirectly, related to the specific recommendations or views expressed in this research report.

Additional information is available upon request.

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For residents of Malaysia - All queries in relation to this report should be referred to Alexander Chia, Desmond Ch'ng, or Ching Wah Tam.

This investment analysis was prepared from the following sources: S&P MarketScope, S&P Compustat, S&P Industry Reports, I/B/E/S International, Inc.; Standard & Poor's, 55 Water St., New York, NY 10041.

Source: S&P.

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STANDARD &POOR'S

Spectra Energy Corp

S&P Recommendation SELL ★★☆☆☆

Price
$14.37 (as of Feb 13, 2009)

12-Mo. Target Price
$12.00

Investment Style
Large-Cap Blend

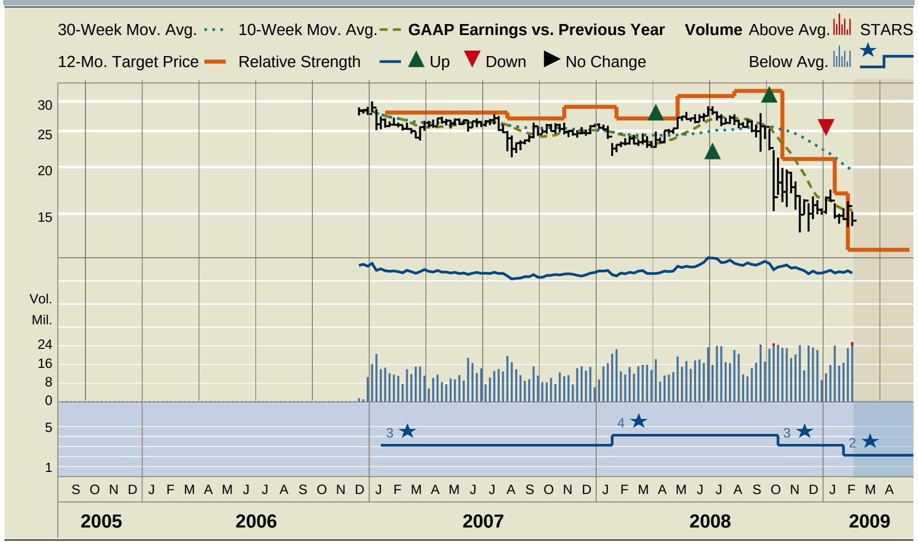
GICS Sector Energy
Sub-Industry Oil & Gas Storage & Transportation

Summary This integrated natural gas holding company is engaged in gas gathering and processing and gas transportation and storage in the U.S. and Canada, and retail gas distribution to 1.3 million customers in Ontario, Canada.

Key Stock Statistics (Source S&P, Vickers, company reports)

52-Wk Range	**$29.18– 13.36**	S&P Oper. EPS 2009**E**	**1.15**	Market Capitalization(B)	**$8.781**	Beta	**0.93**
Trailing 12-Month EPS	**$1.81**	S&P Oper. EPS 2010**E**	**NA**	Yield (%)	**6.96**	S&P 3-Yr. Proj. EPS CAGR(%)	**-8**
Trailing 12-Month P/E	**7.9**	P/E on S&P Oper. EPS 2009**E**	**12.5**	Dividend Rate/Share	**$1.00**	S&P Credit Rating	**NA**
$10K Invested 5 Yrs Ago	**NA**	Common Shares Outstg. (M)	**611.0**	Institutional Ownership (%)	**63**		

Price Performance



Options: ASE, CBOE, Ph

Analysis prepared by **Tanjila Shafi** on February 10, 2009, when the stock traded at **$ 14.65**.

Highlights

- We expect revenues in 2009 to decline due to lower volume, reflecting recessionary headwinds. By the end of 2008, a number of key projects in the U.S. Transmission segment were placed in service, including Gulfstream Phase III, Egan Storage Cavern 4, Southeast Supply Header, Maritimes & Northeast Phase IV, Glade Spring Expansion, TIME II, and Ramapo. By the end of the first quarter of 2009, the company expects that Phase III of the Dawn-Trafalgar expansion and the Dawn Storage Deliverability project should come on line. We expect that the new projects will add $130 million in EBIT this year.

- The company allocated approximately $1.8 billion for expansion capital expenditures during 2008. We believe it will incur $500 million in capital expenditures in 2009.

- SE declared a cash distribution of $0.25 per unit for the 2008 fourth quarter, 13.6% above the 2007 fourth quarter distribution of $0.22. For 2009, we see distributions of $1.00.

Investment Rationale/Risk

- Our recent downgrade to a sell recommendation is based on our concern that the challenging operating climate will limit earnings in 2009. We see volumes moderating in 2009 due to the recessionary environment. SE was formed on January 2, 2007, after Duke Energy spun off its natural gas businesses. SE operates a large and diverse portfolio of natural gas transportation and storage assets in the U.S. and Canada. In July 2007, SE spun off some assets into Spectra Energy Partners L.P. (SEP, $20) and received $345 million.

- Risks to our recommendation and target price include an acceleration of natural gas production growth, increases in long-term natural gas prices, and a favorable credit environment.

- Our 12-month target price of $12 is a blend of 11X our 2009 EPS estimate, 9.0X enterprise value-to-EBITDA, based on our 2009 estimate, and a target yield of 8.5% on projected dividends, in line with peers.

Qualitative Risk Assessment

LOW	**MEDIUM**	HIGH

Our risk assessment reflects the company's large market capitalization and the lower risk inherent in its regulated gas transmission and distribution businesses, offset by its investments in higher-risk gas gathering and processing businesses.

Quantitative Evaluations

S&P Quality Ranking **NR**

D	C	B-	B	B+	A-	A	A+

Relative Strength Rank **MODERATE**

40

LOWEST = 1 HIGHEST = 99

Revenue/Earnings Data

Revenue (Million $)

	1Q	2Q	3Q	4Q	Year
2008	1,608	1,141	1,080	1,261	5,074
2007	1,401	985.0	959.0	1,397	4,742
2006	NA	NA	NA	--	4,532
2005	--	--	--	--	4,132
2004	--	--	--	--	--
2003	--	--	--	--	--

Earnings Per Share ($)

2008	0.58	0.47	0.49	0.27	1.81
2007	0.37	0.29	0.38	0.45	1.49
2006	NA	NA	NA	--	NA
2005	--	--	--	--	1.07
2004	--	--	--	--	--
2003	--	--	--	--	--

Fiscal year ended Dec. 31. Next earnings report expected: Early May. EPS Estimates based on S&P Operating Earnings; historical GAAP earnings are as reported.

Dividend Data (Dates: mm/dd Payment Date: mm/dd/yy)

Amount ($)	Date Decl.	Ex-Div. Date	Stk. of Record	Payment Date
0.230	04/04	05/14	05/16	06/16/08
0.250	07/03	08/13	08/15	09/15/08
0.250	10/28	11/12	11/14	12/15/08
0.250	01/05	02/11	02/13	03/16/09

Dividends have been paid since 2007. Source: Company reports.

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Spectra Energy Corp

STANDARD &POOR'S

Business Summary February 10, 2009

CORPORATE OVERVIEW. SE owns and operates a diversified portfolio of natural gas-related energy assets and is primarily a natural gas midstream company. The company operates in three areas of the natural gas industry: transmission and storage, distribution, and gathering and processing. SE also owns a natural gas distribution company, Union Gas, and participates in a 50%-owned joint venture, DCP Midstream.

MARKET PROFILE. The company manages its business in four segments: U.S. Transmission, Distribution, Western Canada Transmission and Processing, and Field Services.

The U.S. Transmission segment provides transportation and storage of natural gas for customers in the eastern and southeastern U.S. and the Maritime provinces of Canada. The segment has 12,915 miles of natural gas pipelines and 85 billion cubic feet (bcf) of storage capacity. The company's largest pipeline, Texas Eastern Transmission, is 9,040 miles, has a capacity of 6.2 billion cubic feet per day (bcf/d), and has 75.1 bcf of storage capacity. The pipeline connects Gulf Coast gas supply to demand centers in the Northeast, as well as to the East Tennessee Natural Gas and Algonquin Gas Transmission pipelines. The Algonquin pipeline can transport 1.9 bcf/d and connects to both the Texas Eastern and Maritimes and Northeast pipelines to provide gas to areas between Boston, MA, and northern New Jersey. The East Tennessee pipeline brings gas from the Texas Eastern pipeline through eastern Tennessee as far as Roanoke, VA. The 50%-owned Gulfstream pipeline brings natural gas into the fast growing state of Florida. The Maritimes and Northeast pipeline provides Sable Island area Canadian natural gas down into the Boston area and helps to supply the Algonquin pipeline. The segment also operates other pipeline interconnection assets and storage assets.

The Distribution segment provides retail natural gas distribution in Ontario, Canada, as well as natural gas transportation and storage services to other utilities and energy market participants in Ontario, Quebec and the U.S. Union Gas is the company's regulated transmission and distribution subsidiary, serving 1.3 million customers in 400 communities throughout Ontario, Canada. Union Gas distributes its gas through 21,600 miles of distribution pipelines and owns 2,750 miles of transmission pipelines and 150 bcf of high deliverability storage.

The Western Canada Transmission and Processing segment provides transportation, gathering and processing of natural gas and natural gas liquid (NGL) extraction, fractionation, transportation, storage and marketing to customers in western Canada and the northern U.S. It owns and operates BC Field Services, BC Pipeline and Natural Gas Liquids. BC Field Services operates 1,800 miles of gas gathering pipelines and five natural gas processing facilities with a capacity of about 2.0 bcf/d for delivery to the western Canadian, Midwestern U.S. and U.S. Pacific Northwest regions. BC Pipeline stretches 1,600 miles, has a capacity of 1.9 bcf/d, and connects to four other pipelines. The pipeline transports gas gathered in British Columbia to the U.S. border and points in between. Natural Gas Liquids has a natural gas liquids (NGLs) extraction capacity of 2.4 bcf/d and a fractionation capacity of 55,000 b/d. The NGLs can be transported through 580 miles of pipelines to major NGL sales pipelines in Canada and the U.S. The NGLs can also be stored in an underground facility with a capacity of 4 million barrels and seven trucking and three rail shipping facilities. WCT also has a 46% stake in the publicly traded Spectra Energy Income Fund and operates the natural gas gathering and processing facilities owned by the fund.

The Field Services segment gathers, compresses, processes, transports, trades, markets and stores NGLs. It conducts operations primarily through DCP Midstream, a 50%-owned joint venture with ConocoPhillips. DCP gathers raw natural gas through 56,000 miles of gathering pipe and processes it through 53 owned or operated plants. DCP also owns 10 fractionating facilities.

CORPORATE STRATEGY. SE aims to create shareholder value through a three-pronged approach. First, the company plans to emphasize cost control, while maintaining its emphasis on growing customer and other external stakeholder relationships. The company has said it plans to utilize tax efficient financial structures, such as master limited partnerships, to improve its cost of capital. Second, the company plans to invest about $1.0 billion annually to build organic and greenfield expansion projects. Finally, the company intends to pursue accretive third-party acquisitions.

FINANCIAL TRENDS. As of December 31, 2007, SE had a long-term debt-to-total capitalization ratio of 55%, which is at the low end of management's targeted ratio of 55% to 60%. Based on the company's cash and cash equivalents and its ability to draw on large revolving credit facilities, we believe liquidity is ample.

Corporate Information

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Chrmn
P.R. Anderson

CFO
J.P. Reddy

Pres & CEO
G.L. Ebel

Chief Admin Officer
D.M. Ables

COO
A.N. Harris

Board Members
A. A. Adams
P. R. Anderson
P. L. Carter
F. A. Comper
W. T. Esrey
F. J. Fowler
P. B. Hamilton
D. R. Hendrix
M. McShane
M. E. Phelps

Domicile
Delaware

Founded
2006

Employees
5,100

Stockholders
525,281

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Spectra Energy Corp

STANDARD &POOR'S

Quantitative Evaluations

S&P Fair Value Rank 2+

1	2	3	4	5
LOWEST				HIGHEST

Based on S&P's proprietary quantitative model, stocks are ranked from most overvalued (1) to most undervalued (5).

Fair Value Calculation $15.10

Analysis of the stock's current worth, based on S&P's proprietary quantitative model suggests that SE is slightly undervalued by $0.73 or 5.1%.

Investability Quotient Percentile

53

LOWEST = 1 HIGHEST = 100

SE scored higher than 53% of all companies for which an S&P Report is available.

Volatility

LOW | AVERAGE | HIGH

Technical Evaluation BEARISH

Since January, 2009, the technical indicators for SE have been BEARISH.

Insider Activity NA

UNFAVORABLE | NEUTRAL | FAVORABLE

Expanded Ratio Analysis

	2008	2007	2006	2005
Price/Sales	NA	3.46	NA	NA
Price/EBITDA	NA	8.34	NA	NA
Price/Pretax Income	NA	11.25	NA	NA
P/E Ratio	NA	17.37	NA	NA
Avg. Diluted Shares Outstg (M)	NA	635.0	NA	NA

Figures based on calendar year-end price

Key Growth Rates and Averages

Past Growth Rate (%)	1 Year	3 Years	5 Years	9 Years
Sales	7.00	6.84	-17.57	NA
Net Income	19.60	27.63	NM	NA
Ratio Analysis (Annual Avg.)				
Net Margin (%)	22.25	20.94	14.25	NA
Return on Equity (%)	18.21	14.74	NA	NA

Company Financials Fiscal Year Ended Dec. 31

Per Share Data ($)	2008	2007	2006	2005	2004	2003	2002	2001	2000	1999
Tangible Book Value	NA	4.60	NM	NA	NA	NA	NA	NA	NA	NA
Cash Flow	NA	2.31	NA	2.04	NA	NA	NA	NA	NA	NA
Earnings	1.81	1.49	NA	1.07	NA	NA	NA	NA	NA	NA
S&P Core Earnings	NA	1.46	NA	NA	NA	NA	NA	NA	NA	NA
Dividends	NA	0.88	Nil	Nil	NA	NA	NA	NA	NA	NA
Payout Ratio	NA	59%	Nil	Nil	NA	NA	NA	NA	NA	NA
Prices:High	NA	30.00	29.00	NA	NA	NA	NA	NA	NA	NA
Prices:Low	NA	21.24	27.50	NA	NA	NA	NA	NA	NA	NA
P/E Ratio:High	NA	20	NA	NA	NA	NA	NA	NA	NA	NA
P/E Ratio:Low	NA	14	NA	NA	NA	NA	NA	NA	NA	NA
Income Statement Analysis (Million $)										
Revenue	5,074	4,742	4,532	4,132	13,255	10,784	NA	NA	NA	NA
Operating Income	NA	1,967	1,804	1,697	NA	NA	NA	NA	NA	NA
Depreciation	554	525	606	458	NA	NA	NA	NA	NA	NA
Interest Expense	636	651	605	607	744	806	NA	NA	NA	NA
Pretax Income	1,688	1,458	1,376	862	1,156	719	NA	NA	NA	NA
Effective Tax Rate	29.4%	30.4%	28.7%	41.7%	123.8%	29.2%	NA	NA	NA	NA
Net Income	1,129	944	936	502	-489	404	NA	NA	NA	NA
S&P Core Earnings	NA	928	926	NA	NA	NA	NA	NA	NA	NA
Balance Sheet & Other Financial Data (Million $)										
Cash	214	94.0	299	NA	NA	NA	NA	NA	NA	NA
Current Assets	NA	1,379	1,625	18,601	NA	NA	NA	NA	NA	NA
Total Assets	21,924	22,970	20,345	21,442	NA	NA	NA	NA	NA	NA
Current Liabilities	NA	2,422	2,358	2,052	NA	NA	NA	NA	NA	NA
Long Term Debt	NA	8,345	7,726	7,957	NA	NA	NA	NA	NA	NA
Common Equity	5,540	6,857	5,639	5,225	NA	NA	NA	NA	NA	NA
Total Capital	NA	16,008	16,910	16,100	NA	NA	NA	NA	NA	NA
Capital Expenditures	2,030	1,202	987	NA	NA	NA	NA	NA	NA	NA
Cash Flow	NA	1,469	1,542	960	NA	NA	NA	NA	NA	NA
Current Ratio	0.5	0.6	0.7	NA	NA	NA	NA	NA	NA	NA
% Long Term Debt of Capitalization	59.9	52.1	45.7	Nil	Nil	Nil	NA	NA	NA	NA
% Net Income of Revenue	22.3	19.9	20.7	12.2	NM	3.8	NA	NA	NA	NA
% Return on Assets	NA	4.4	3.4	NA	NA	NA	NA	NA	NA	NA
% Return on Equity	18.2	15.1	10.9	NA	NA	NA	NA	NA	NA	NA

Data as orig reptd.; bef. results of disc opers/spec. items. Per share data adj. for stk. divs.; EPS diluted. E-Estimated. NA-Not Available. NM-Not Meaningful. NR-Not Ranked. UR-Under Review.

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Spectra Energy Corp

STANDARD &POOR'S

Sub-Industry Outlook

Our fundamental outlook for the oil and gas storage and transportation sub-industry for the next 12 months is neutral. We expect fee-based pipeline and terminal operators to continue to expand earnings well in excess of anticipated real U.S. GDP growth in 2008 and 2009. As of January, S&P estimated a 1.1% increase in U.S. real GDP for 2008 and a 2.0% decline for 2009, compared to the 2.0% rise in 2007. However, we believe that investors are concerned that the tightening credit market may hinder MLPs from raising capital to fund their expansion projects. In response to the poor credit environment and weak economy, many MLPs plan to reduce their capital expansion budgets for 2009 to preserve capital and maintain their dividends.

We believe that 2009 will be a volatile year for tanker companies. Based on industry research group Bassoe, daily spot charter rates for VLCCs were $66,000 in the fourth quarter of 2008, below the $91,000 average in the third quarter. We expect tanker rates to continue to soften in 2009, due to the expected increase in the worldwide fleet, cuts in OPEC production, and the slowing global economy. The shipping industry suffered from increased piracy in 2008. If piracy is not curtailed, many shippers will re-route their vessels, leading to longer and more expensive trips, in our opinion.

As of early January 2009, the Energy Information Administration (EIA) estimated that U.S. petroleum consumption declined 5.7% in 2008 and would fall another 2.0% in 2009, after being little changed in 2007. The EIA also estimated that natural gas consumption would increase 0.7% in 2008 and decline 1.0% in 2009. Longer term, we think drivers for new transportation infrastructure include new import terminals for liquefied natural gas, transcontinental movement of gas from the Rockies to Northeast markets, and increased oil sands production in Alberta. In our view, an active merger and acquisition environment will also remain a principal investor focus. Current yields as of February 3, 2009, on our universe of MLPs averaged about 11.0%, above the benchmark 10-year Treasury note, which was yielding about 2.83% at that time.

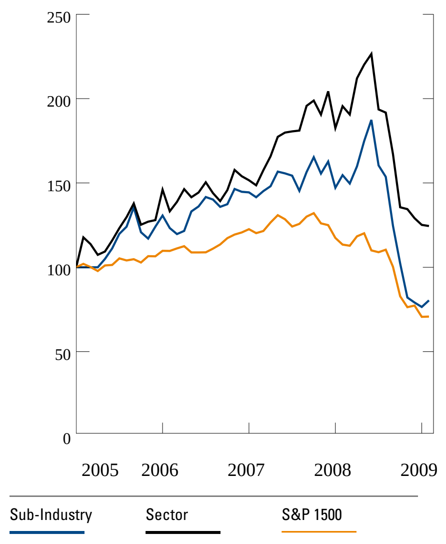
Year to date through February 2, the S&P Oil and Gas Storage and Transportation Index rose 1.1%, versus a 8.6% decline for the S&P 1500. In 2008, the S&P Oil and Gas Storage and Transportation Index was down 10.5%, versus a 38.2% decline for the S&P 1500. Our preference is for those issues with the potential to increase cash flow and dividend payouts over time.

--T. Shafi

Stock Performance

GICS Sector: **Energy**
Sub-Industry: **Oil & Gas Storage & Transportation**

Based on S&P 1500 Indexes
Month-end Price Performance as of 01/30/09



NOTE: All Sector & Sub-Industry information is based on the Global Industry Classification Standard (GICS)

Sub-Industry : Oil & Gas Storage & Transportation Peer Group*: Based on market capitalizations within GICS Sub-Industry

Peer Group	Stock Symbol	Stk.Mkt. Cap. (Mil. $)	Recent Stock Price($)	52 Week High/Low($)	Beta	Yield (%)	P/E Ratio	Fair Value Calc.($)	Quality Ranking	S&P IQ %ile	Return on Revenue (%)	LTD to Cap (%)
Spectra Energy	**SE**	**8,781**	**14.37**	**29.18/13.36**	**0.93**	**7.0**	**8**	**15.10**	**NR**	**53**	**22.3**	**59.9**
Boardwalk Pipeline Ptnrs LP	BWP	3,514	22.44	29.80/14.00	0.06	8.6	13	NA	NR	92	37.5	NA
Cheniere Energy Ptnrs L.P.	CQP	1,010	6.24	17.57/3.65	NA	27.2	NM	NA	NR	52	NM	NA
Eagle Rock Energy Ptnrs L.P.	EROC	508	7.02	17.96/4.00	0.15	23.4	NM	NA	NR	66	NM	43.8
El Paso Pipeline Ptnrs L.P.	EPB	2,049	18.18	24.35/11.72	NA	6.3	23	NA	NR	38	60.0	53.8
Energy Transfer Equity L.P.	ETE	4,361	19.57	35.02/12.75	0.79	10.4	13	NA	NR	30	4.7	NA
Enterprise GP Holdings L.P.	EPE	2,801	22.74	33.76/14.50	0.38	8.3	17	NA	NR	85	0.4	51.0
Genesis Energy L.P.	GEL	479	12.15	22.33/6.42	1.57	10.9	NM	NA	NR	72	NM	10.9
Inergy Holding LP	NRGP	617	30.50	46.97/14.35	0.36	8.9	16	NA	NR	23	1.9	91.7
Kayne Anderson MLP Inv	KYN	820	19.50	31.45/11.07	0.91	10.3	NM	NA	NR	44	NA	NA
NuStar GP Hldgs LLC	NSH	839	19.73	28.41/12.16	0.48	8.7	13	NA	NR	78	NM	NA
Regency Energy Ptnrs LP	RGNC	912	11.23	31.18/4.92	0.98	15.9	13	10.60	NR	33	NM	50.3
Southern Union	SUG	1,710	13.79	28.62/10.60	1.28	4.4	8	15.20	B	72	8.7	50.5
Williams Partners L.P.	WPZ	909	17.23	38.00/9.96	0.81	14.7	6	NA	NR	50	28.7	86.1
Williams Pipeline Ptnrs L.P.	WMZ	547	16.31	20.04/10.55	NA	7.8	4	NA	NR	74	NA	NA

NA-Not Available NM-Not Meaningful NR-Not Rated. *For Peer Groups with more than 15 companies or stocks, selection of issues is based on market capitalization.

Source: S&P.

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Spectra Energy Corp

S&P Analyst Research Notes and other Company News

February 5, 2009
12:12 pm ET ... S&P DOWNGRADES OPINION ON SHARES OF SPECTRA ENERGY TO SELL FROM HOLD (SE 15.03**): SE posts Q4 earnings per unit of $0.28 vs. $0.46, missing our $0.40 estimate. The shortfall reflects lower volumes, higher costs, a decline in spreads, and a weaker Canadian dollar. We are lowering our 2009 earnings per unit estimate to $1.15 from $1.78, to reflect the macroeconomic headwinds and company guidance. We are also reducing our 12-month target price to $12 from $17, based on a blend of 11X our 2009 earnings estimate, a 9.0X enterprise value-to-our '09 EBITDA estimate, and a target yield of 8.4% on projected dividends. /T.Shafi

January 14, 2009
03:25 pm ET ... S&P MAINTAINS HOLD OPINION ON SHARES OF SPECTRA ENERGY (SE 14.8***): Ahead of Q4 report scheduled for February 5, we are decreasing our earnings per unit forecast to $0.40 from $0.46. We believe that the recessionary environment will reduce volumes and impact the company's revenue growth. We are lowering our '09 earnings per unit estimate to $1.78 from $2.05, reflecting macroeconomic headwinds. We are lowering our 12-month target price to $17 from $21, based on a blend of 9X our '09 EPS forecast, 8.5X enterprise value-to-our '09 EBITDA estimate, and a target yield of 5.3% on projected dividends. /T.Shafi

December 18, 2008
Spectra Energy Corp. has announced the senior executive team that will lead the corporation following current President and CEO Fred Fowler's retirement at the end of 2008. In addition to the previously announced appointment of Greg Ebel as President and CEO, Dorothy Ables, currently VP of Audit Services, will take on a new role of Chief Administrative Officer, John Arensdorf, currently VP of Investor Relations, will become Chief Communications Officer, Doug Bloom will continue in his current role as President of Spectra Energy's Western Canadian business, Julie Dill will continue as President of Union Gas, Spectra Energy's Ontario distribution business, Mark Fiedorek continues as Group VP, US Southeast Transmission and Storage, Alan Harris, currently Chief Development Officer, will take on additional responsibilities as Chief Development and Operations Officer, and Bill Yardley will continue as Group VP, US Northeast Transmission.

December 15, 2008
Spectra Energy Corp. announced the appointment of John Patrick (Pat) Reddy as its new chief financial officer. Reddy, currently senior vice president and CFO with Atmos Energy Corporation in Dallas will join Spectra Energy on January 1, 2009. Reddy has more than 28 years of finance experience in the energy industry. Prior to his current role, Reddy held the position of vice president, corporate development, and treasurer, with Atmos Energy Corporation, where he has been since 1998.

December 3, 2008
Spectra Energy Corp. announced the appointment of John Patrick (Pat) Reddy as its new chief financial officer (CFO). Reddy, currently senior vice president and CFO with Atmos Energy Corporation in Dallas, will join Spectra Energy on January 1, 2009. Reddy has more than 28 years of finance experience in the energy industry. Prior to his current role, Reddy held the position of vice president, corporate development, and treasurer, with Atmos Energy Corporation, where he has been since 1998.

November 10, 2008
Spectra Energy Corp. announced the departure of William S. Garner, Jr., Group Executive, General Counsel and Secretary.

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Spectra Energy Corp

STANDARD
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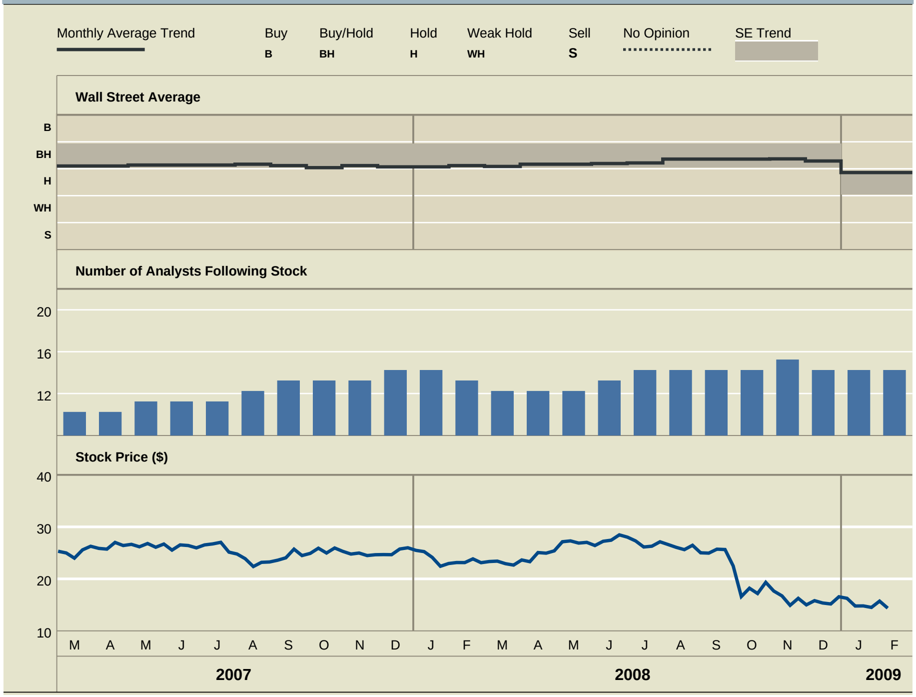
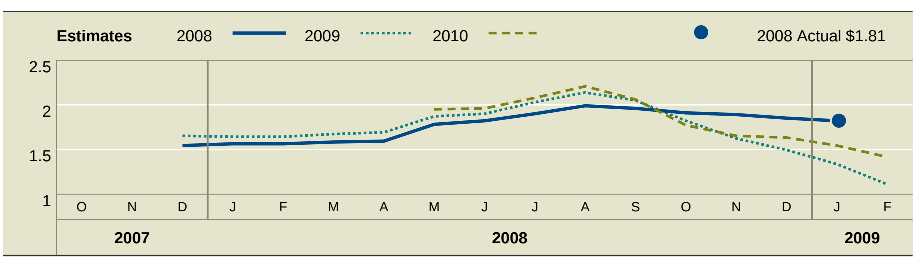
Analysts' Recommendations



Of the total 14 companies following SE, 14 analysts currently publish recommendations.

	No. of Ratings	% of Total	1 Mo. Prior	3 Mos. Prior
Buy	2	14	2	3
Buy/Hold	4	29	4	7
Hold	8	57	6	5
Weak Hold	0	0	1	0
Sell	0	0	1	0
No Opinion	0	0	0	0
Total	**14**	**100**	**14**	**15**

Wall Street Consensus Estimates



Fiscal Years	Avg Est.	High Est.	Low Est.	# of Est.	Est. P/E
2010	1.42	1.66	1.24	14	10.1
2009	1.11	1.33	1.00	14	12.9
2010 vs. 2009	**▲ 28%**	**▲ 25%**	**▲ 24%**	**0%**	**▼ -22%**
Q1'10	0.45	0.53	0.41	3	31.9
Q1'09	0.35	0.46	0.31	9	41.1
Q1'10 vs. Q1'09	**▲ 29%**	**▲ 15%**	**▲ 32%**	**▼ -67%**	**▼ -22%**

A company's earnings outlook plays a major part in any investment decision. Standard & Poor's organizes the earnings estimates of over 2,300 Wall Street analysts, and provides their consensus of earnings over the next two years. This graph shows the trend in analyst estimates over the past 15 months.

Wall Steet Consensus Opinion

BUY/HOLD

Companies Offering Coverage

Argus Research Corp.
Atlantic Equities
Barclays Capital
CIBC World Markets
Deutsche Bank
Goldman Sachs & Co.
Harris Nesbitt
Jefferies & Company
Macquarie Research Equities
Pickering Energy Partners, Inc.
RBC Capital Markets (US)
Smith Barney
UBS Warburg
Wachovia Securities

Wall Street Consensus vs. Performance

For fiscal year 2009, analysts estimate that SE will earn $1.11. For fiscal year 2010, analysts estimate that SE's earnings per share will grow by 28% to $1.42.

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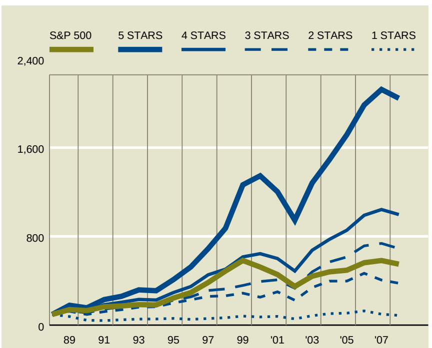
Spectra Energy Corp

Glossary

S&P STARS
Since January 1, 1987, Standard and Poor's Equity Research Services has ranked a universe of common stocks based on a given stock's potential for future performance. Under proprietary STARS (STock Appreciation Ranking System), S&P equity analysts rank stocks according to their individual forecast of a stock's future total return potential versus the expected total return of a relevant benchmark (e.g., a regional index (S&P Asia 50 Index, S&P Europe 350 Index or S&P 500 Index)), based on a 12-month time horizon. STARS was designed to meet the needs of investors looking to put their investment decisions in perspective.

STARS Average Annual Performance



S&P 12-Month Target Price
The S&P equity analyst's projection of the market price a given security will command 12 months hence, based on a combination of intrinsic, relative, and private market valuation metrics.

Investment Style Classification
Characterizes the stock as Growth or Value, and indicates its capitalization level. Growth is evaluated along three dimensions (earnings, sales and internal growth), while Value is evaluated along four dimensions (book-to-price, cash flow-to-price, dividend yield and sale-to-price). Growth stocks score higher than the market average on growth dimensions and lower on value dimensions. The reverse is true for Value stocks. Certain stocks are classified as Blend, indicating a mixture of growth and value characteristics and cannot be classified as purely growth or value.

Qualitative Risk Assessment
The S&P equity analyst's view of a given company's operational risk, or the risk of a firm's ability to continue as an ongoing concern. The Qualitative Risk Assessment is a relative ranking to the S&P U.S. STARS universe, and should be reflective of risk factors related to a company's operations, as opposed to risk and volatility measures associated with share prices.

Quantitative Evaluations
In contrast to our qualitative STARS recommendations, which are assigned by S&P analysts, the quantitative evaluations described below are derived from proprietary arithmetic models. These computer-driven evaluations may at times contradict an analyst's qualitative assessment of a stock. One primary reason for this is that different measures are used to determine each. For instance, when designating STARS, S&P analysts assess many factors that cannot be reflected in a model, such as risks and opportunities, management changes, recent competitive shifts, patent expiration, litigation risk, etc.

S&P Quality Ranking
Growth and stability of earnings and dividends are deemed key elements in establishing S&P's Quality Rankings for common stocks, which are designed to capsulize the nature of this record in a single symbol. It should be noted, however, that the process also takes into consideration certain adjustments and modifications deemed desirable in establishing such rankings. The final score for each stock is measured against a scoring matrix determined by analysis of the scores of a large and representative sample of stocks. The range of scores in the array of this sample has been aligned with the following ladder of rankings:

A+	Highest	B	Below Average
A	High	B-	Lower
A-	Above Average	C	Lowest
B+	Average	D	In Reorganization
NR	Not Ranked		

S&P Fair Value Rank
Using S&P's exclusive proprietary quantitative model, stocks are ranked in one of five groups, ranging from Group 5, listing the most undervalued stocks, to Group 1, the most overvalued issues. Group 5 stocks are expected to generally outperform all others. A positive (+) or negative (-) Timing Index is placed next to the Fair Value ranking to further aid the selection process.A stock with a (+) added to the Fair Value Rank simply means that this stock has a somewhat better chance to outperform other stocks with the same Fair Value Rank. A stock with a (-) has a somewhat lesser chance to outperform other stocks with the same Fair Value Rank. The Fair Value rankings imply the following: 5-Stock is significantly undervalued; 4-Stock is moderately undervalued; 3-Stock is fairly valued; 2-Stock is modestly overvalued; 1-Stock is significantly overvalued.

S&P Fair Value Calculation
The price at which a stock should trade at, according to S&P's proprietary quantitative model that incorporates both actual and estimated variables (as opposed to only actual variables in the case of S&P Quality Ranking). Relying heavily on a company's actual return on equity, the S&P Fair Value model places a value on a security based on placing a formula-derived price-to-book multiple on a company's consensus earnings per share estimate.

Insider Activity
Gives an insight as to insider sentiment by showing whether directors, officers and key employees who have proprietary information not available to the general public, are buying or selling the company's stock during the most recent six months.

Funds From Operations FFO
FFO is Funds from Operations and equal to a REIT's net income, excluding gains or losses from sales of property, plus real estate depreciation.

Investability Quotient (IQ)
The IQ is a measure of investment desirability. It serves as an indicator of potential medium-to-long term return and as a caution against downside risk. The measure takes into account variables such as technical indicators, earnings estimates, liquidity, financial ratios and selected S&P proprietary measures.

S&P's IQ Rationale:
Spectra Energy

	Raw Score	Max Value
Proprietary S&P Measures	35	115
Technical Indicators	29	40
Liquidity/Volatility Measures	14	20
Quantitative Measures	16	75
IQ Total	**94**	**250**

Volatility
Rates the volatility of the stock's price over the past year.

Technical Evaluation
In researching the past market history of prices and trading volume for each company, S&P's computer models apply special technical methods and formulas to identify and project price trends for the stock.

Relative Strength Rank
Shows, on a scale of 1 to 99, how the stock has performed versus all other companies in S&P's universe on a rolling 13-week basis.

Global Industry Classification Standard (GICS)
An industry classification standard, developed by Standard & Poor's in collaboration with Morgan Stanley Capital International (MSCI). GICS is currently comprised of 10 Sectors, 24 Industry Groups, 68 Industries, and 154 Sub-Industries.

S&P Issuer Credit Rating
A Standard & Poor's Issuer Credit Rating is a current opinion of an obligor's overall financial capacity (its creditworthiness) to pay its financial obligations. This opinion focuses on the obligor's capacity and willingness to meet its financial commitments as they come due. It does not apply to any specific financial obligation, as it does not take into account the nature of and provisions of the obligation, its standing in bankruptcy or liquidation, statutory preferences, or the legality and enforceability of the obligation. In addition, it does not take into account the creditworthiness of the guarantors, insurers, or other forms of credit enhancement on the obligation. The Issuer Credit Rating is not a recommendation to purchase, sell, or hold a financial obligation issued by an obligor, as it does not comment on market price or suitability for a particular investor. Issuer Credit Ratings are based on current information furnished by obligors or obtained by Standard & Poor's from other sources it considers reliable. Standard & Poor's does not perform an audit in connection with any Issuer Credit Rating and may, on occasion, rely on unaudited financial information. Issuer Credit Ratings may be changed, suspended, or withdrawn as a result of changes in, or unavailability of, such information, or based on other circumstances.

Exchange Type
ASE - American Stock Exchange; NNM - Nasdaq National Market; NSC - Nasdaq SmallCap; NYSE - New York Stock Exchange; BB - OTC Bulletin Board; OT - Over-the-Counter; TO - Toronto Stock Exchange.

S&P Equity Research Services
Standard & Poor's Equity Research Services U.S. includes Standard & Poor's Investment Advisory Services LLC; Standard & Poor's Equity Research Services Europe includes Standard & Poor's LLC-London and Standard & Poor's AB (Sweden); Standard & Poor's Equity Research Services Asia includes Standard & Poor's LLC's offices in Hong Kong, Singapore and Tokyo, Standard & Poor's Malaysia Sdn Bhd, and Standard & Poor's Information Services (Australia) Pty Ltd.

Abbreviations Used in S&P Equity Research Reports
CAGR- Compound Annual Growth Rate; **CAPEX**- Capital Expenditures; **CY**- Calendar Year; **DCF**- Discounted Cash Flow; **EBIT**- Earnings Before Interest and Taxes; **EBITDA**- Earnings Before Interest, Taxes, Depreciation and Amortization; **EPS**- Earnings Per Share; **EV**- Enterprise Value; **FCF**- Free Cash Flow; **FFO**- Funds From Operations; **FY**- Fiscal Year; **P/E**- Price/Earnings ; **PEG Ratio**- P/E-to-Growth Ratio; **PV**- Present Value; **R&D**- Research & Development; **ROE**- Return on Equity; **ROI**- Return on Investment; **ROIC**- Return on Invested Capital; **ROA**- Return on Assets; **SG&A**- Selling, General & Administrative Expenses; **WACC**- Weighted Average Cost of Capital

Dividends on American Depository Receipts (ADRs) and American Depository Shares (ADSs) are net of taxes (paid in the country of origin).

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Spectra Energy Corp

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S&P Global STARS Distribution

In North America: As of December 31, 2008, research analysts at Standard & Poor's Equity Research Services U.S. have recommended 27.0% of issuers with buy recommendations, 61.2% with hold recommendations and 11.8% with sell recommendations.

In Europe: As of December 31, 2008, research analysts at Standard & Poor's Equity Research Services Europe have recommended 30.4% of issuers with buy recommendations, 45.3% with hold recommendations and 24.3% with sell recommendations.

In Asia: As of December 31, 2008, research analysts at Standard & Poor's Equity Research Services Asia have recommended 33.9% of issuers with buy recommendations, 54.4% with hold recommendations and 11.7% with sell recommendations.

Globally: As of December 31, 2008, research analysts at Standard & Poor's Equity Research Services globally have recommended 28.1% of issuers with buy recommendations, 58.3% with hold recommendations and 13.6% with sell recommendations.

★★★★★ **5-STARS (Strong Buy)**: Total return is expected to outperform the total return of a relevant benchmark, by a wide margin over the coming 12 months, with shares rising in price on an absolute basis.

★★★★☆ **4-STARS (Buy)**: Total return is expected to outperform the total return of a relevant benchmark over the coming 12 months, with shares rising in price on an absolute basis.

★★★☆☆ **3-STARS (Hold)**: Total return is expected to closely approximate the total return of a relevant benchmark over the coming 12 months, with shares generally rising in price on an absolute basis.

★★☆☆☆ **2-STARS (Sell)**: Total return is expected to underperform the total return of a relevant benchmark over the coming 12 months, and the share price not anticipated to show a gain.

★☆☆☆☆ **1-STARS (Strong Sell)**: Total return is expected to underperform the total return of a relevant benchmark by a wide margin over the coming 12 months, with shares falling in price on an absolute basis.

Relevant benchmarks: In North America the relevant benchmark is the S&P 500 Index, in Europe and in Asia, the relevant benchmarks are generally the S&P Europe 350 Index and the S&P Asia 50 Index.

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STANDARD &POOR'S

TC PipeLines LP

S&P Recommendation HOLD ★★★★★

Price
$25.29 (as of Feb 13, 2009)

12-Mo. Target Price
$29.00

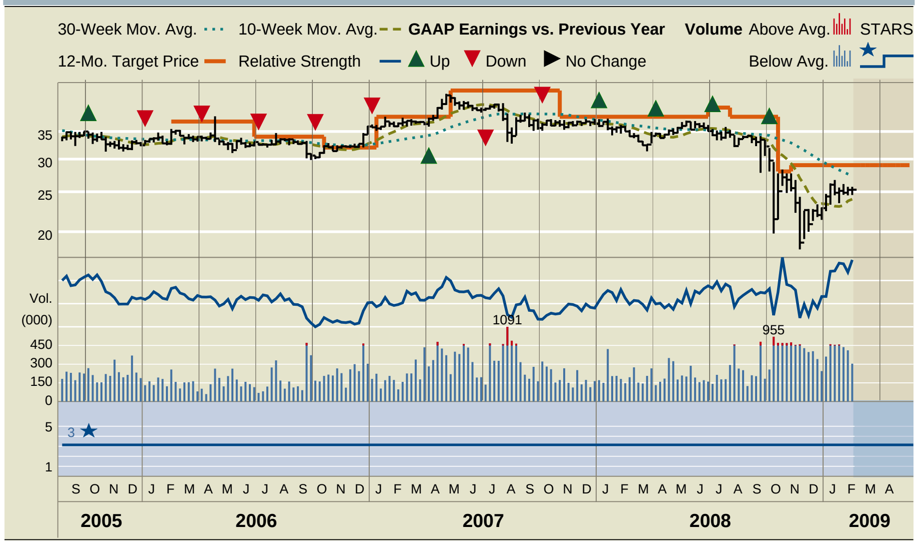
GICS Sector Energy
Sub-Industry Oil & Gas Storage & Transportation

Summary This partnership has interests in three interstate natural gas pipelines, including a 46.5% stake in Great Lakes Gas Transmission LP.

Key Stock Statistics (Source S&P, Vickers, company reports)

52-Wk Range	**$37.29– 18.11**	S&P Oper. EPS 2008**E**	**2.73**	Market Capitalization(B)	**$0.882**	Beta	**0.75**
Trailing 12-Month EPS	**$2.78**	S&P Oper. EPS 2009**E**	**2.59**	Yield (%)	**11.15**	S&P 3-Yr. Proj. EPS CAGR(%)	**2**
Trailing 12-Month P/E	**9.1**	P/E on S&P Oper. EPS 2008**E**	**9.3**	Dividend Rate/Share	**$2.82**	S&P Credit Rating	**NA**
$10K Invested 5 Yrs Ago	**$10,956**	Common Shares Outstg. (M)	**34.9**	Institutional Ownership (%)	**34**		

Price Performance



Analysis prepared by **Tanjila Shafi** on January 12, 2009, when the stock traded at **$ 25.68**.

Highlights

- We believe that the company's 100% interest in Tuscarora Gas Transmission Company will add stable cash flow and earnings in 2009 as this segment generates revenues through long-term contracts and is generally not affected by changing natural gas fundamentals. We see the company's 46.45% equity interest in Great Lakes Gas Transmission L.P. benefiting from solid demand for its services.

- We see the company's expansion projects adding to its earnings growth in 2009 and 2010. Its Northern Border interest started construction on the Des Plaines Project in September 2008, with the facilities expected to come online in early 2009. The company's Chicago IV Expansion Project will provide increased downstream capacity, with service expected in 2010.

- TCLP declared a cash distribution of $0.705 per unit for the 2008 third quarter, 6.8% above the 2007 third quarter distribution of $0.66 and the same as last quarter's distribution. Our cash distribution estimate for 2009 is $2.82.

Investment Rationale/Risk

- We think TCLP needs to continue making new acquisitions to maintain its earnings growth. During 2007, the partnership more than doubled its pipeline assets with the purchase of an equity interest in the Great Lakes pipeline. Even so, we believe higher financing costs and tariff rate pressures on the Northern Border Pipeline will pressure profit margins. The company has what we see as a solid balance sheet with a debt-to-capitalization ratio of 38%. And we believe that the company's distribution is adequately covered, providing, by our analysis, the potential for positive total return over the next 12 months.

- Risks to our recommendation and target price include sharply higher interest rates, and a decline in economic activity that reduces demand for energy commodities and thus drives transportation volumes lower.

- Our 12-month target price of $29 is based on a target yield of 9.7% and an estimated 12-month forward distribution of $2.82, in line with its peers.

Qualitative Risk Assessment

LOW	MEDIUM	HIGH

Our risk assessment reflects our view of the partnership's stable financial position and the maturity of principal assets and cash flow produced, partially offset by corporate governance issues inherent in the limited partnership structure.

Quantitative Evaluations

S&P Quality Ranking **NR**

D	C	B-	B	B+	A-	A	A+

Relative Strength Rank **STRONG**

74

LOWEST = 1 HIGHEST = 99

Revenue/Earnings Data

Revenue (Million $)

	1Q	2Q	3Q	4Q	Year
2008	45.00	30.70	40.10	--	--
2007	31.70	30.10	37.10	38.50	137.4
2006	13.20	13.90	17.90	18.40	63.40
2005	14.20	10.40	15.60	13.00	53.20
2004	14.30	14.20	13.10	15.90	57.50
2003	12.30	12.50	12.50	12.50	49.80

Earnings Per Share ($)

2008	0.89	0.47	0.72	**E**0.65	**E**2.73
2007	0.73	0.45	0.64	0.70	2.52
2006	0.67	0.47	0.65	0.60	2.39
2005	0.72	0.52	0.81	0.65	2.70
2004	0.75	0.74	0.68	0.82	2.99
2003	0.66	0.66	0.65	0.66	2.63

Fiscal year ended Dec. 31. Next earnings report expected: Late February. EPS Estimates based on S&P Operating Earnings; historical GAAP earnings are as reported.

Dividend Data (Dates: mm/dd Payment Date: mm/dd/yy)

Amount ($)	Date Decl.	Ex-Div. Date	Stk. of Record	Payment Date
0.700	04/17	04/28	04/30	05/15/08
0.705	07/22	07/29	07/31	08/14/08
0.705	10/17	10/29	10/31	11/14/08
0.705	01/20	01/28	01/30	02/13/09

Dividends have been paid since 1999. Source: Company reports.

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TC PipeLines LP

STANDARD &POOR'S

Business Summary January 12, 2009

CORPORATE OVERVIEW. TC Pipelines LP was formed in 1998 to acquire, own and participate in the management of U.S.-based pipeline assets. TC Pipelines GP, Inc., an indirect wholly owned subsidiary of TransCanada Corporation (TRP), is the general partner of the partnership.

TCLP owns a 50% general partner interest in Northern Border Pipeline Company (NBP), with the remaining 50% general partner interest held by ONEOK Partners, L.P. (OKS), a publicly traded partnership controlled by ONEOK, Inc. (OKE). TRP holds a minority general partner interest in NBP that entitles it to 12.3% of the voting power of NBP. TCLP also owns a 99% general partnership interest in Tuscarora Gas Transmission Company, including a 50% interest acquired on December 19, 2006 for $137 million. TCLP had acquired a 49% interest from TCPL Tuscarora Ltd., an indirect subsidiary of TRP, in September 2000. TRP has the remaining 1% interest in Tuscarora.

On February 22, 2007, TCLP acquired a 46.45% interest in Great Lakes Gas Transmission L.P. from El Paso Corp., for $942 million, including the assumption of $209 million of debt.

PRIMARY BUSINESS DYNAMICS. NBP owns a 1,249-mile interstate pipeline system with capacity of 2.4 billion cubic feet per day that transports natural gas from the Montana-Saskatchewan border to natural gas markets in the U.S. Midwest. NBP had revenues of $309.4 million and net income of $124.1 million in 2007. The primary source of gas transported on the system is in the Western Canadian Sedimentary Basin located in the provinces of Alberta, Saskatchewan, and British Columbia. TCLP estimates that in 2006, the pipeline transported about 20% of the total amount of natural gas imported into the U.S. from Canada. In April 2006, NBP's Chicago III Expansion Project went into service, adding about 130 million cubic feet per day (MMcf/d), or 6%, to its capacity from Harper, Iowa to Chicago. Capacity is fully subscribed under long-term contracts with terms of 5 1/2 to 10 years.

Tuscarora owns a 240-mile, 20-inch diameter, U.S. interstate pipeline system with a subscribed capacity of approximately 180 MMcf/d that originates at an interconnection point with existing facilities of Gas Transmission Northwest Corporation, a wholly owned subsidiary of TransCanada, near Malin, Oregon, and runs southeast through northeastern California and northwestern Nevada. The Tuscarora pipeline system terminates near Wadsworth, Nevada. Tuscarora had revenues of $27.2 million and net income of $11.6 million in 2007.

Great Lakes Gas Transmission L.P. owns a 2,115-mile U.S. interstate pipeline system with capacity of 2.6 billion cubic feet per day, which receives natural gas from TransCanada at the Canadian border near Emerson, Manitoba and serves markets in Minnesota, Northern Wisconsin, Michigan, and eastern Canada. The pipeline reported revenues of $236.2 million and net income of $105.5 million in 2007. TransCanada is the operator of each pipeline.

Shipping rates are regulated by the Federal Energy Regulatory Commission (FERC). NBP serves customers in North and South Dakota, Minnesota, Iowa, Illinois and Indiana. NBP's customers include natural gas producers, marketers, industrial facilities, local distribution companies and electric power generating plants.

Competition among natural gas pipelines is based primarily on transportation charges and proximity to natural gas supply areas and markets. NBP's interstate natural gas pipeline competes with other pipelines that transport Western Canadian natural gas to markets in the West, Midwest and East in North America. NBP also competes with other pipelines that provide access to natural gas storage facilities, alternate supply basins, such as the Rockies, the Mid-Continent, the Permian Basin and the Gulf Coast, and liquefied natural gas.

IMPACT OF MAJOR DEVELOPMENTS. On April 6, 2006, the partnership completed the acquisition of an additional 20% general partnership interest in NBP for approximately $297 million plus a $10 million transaction fee, bringing the partnership's total interest to 50%. Through the acquisition, TCLP indirectly assumed about $120 million of NBP debt. The partnership funded the transaction through a bridge loan credit facility and intends to refinance the loan with a combination of equity and debt. In connection with this transaction, a subsidiary of TransCanada became the operator of NBP in April 2007.

FINANCIAL TRENDS. The partnership uses the equity method of accounting for its investments in NBP and Great Lakes; following the acquisition of an additional 49% interest in Tuscarora, the partnership now consolidates its interest in Tuscarora. In our opinion, TCLP has been able to deliver stable, sustainable cash flow growth, while maintaining a relatively low-risk profile.

TCLP in February 2007 sold a private placement of 17.4 million common units at $34.57 each for gross proceeds of $600 million, which closed concurrently with the acquisition of Great Lakes L.P.

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R. K. Girling
J. Jenkins-Stark
G. A. Lohnes
D. L. Marshall
W. Mirosh

Domicile
Delaware

Founded
1998

Stockholders
13,800

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STANDARD &POOR'S

TC PipeLines LP

Quantitative Evaluations

S&P Fair Value Rank 4

1	2	3	4	5

LOWEST — HIGHEST

Based on S&P's proprietary quantitative model, stocks are ranked from most overvalued (1) to most undervalued (5).

Fair Value Calculation $27.10

Analysis of the stock's current worth, based on S&P's proprietary quantitative model suggests that TCLP is slightly undervalued by $1.81 or 7.2%.

Investability Quotient Percentile 79

LOWEST = 1 — HIGHEST = 100

TCLP scored higher than 79% of all companies for which an S&P Report is available.

Volatility LOW | AVERAGE | HIGH

Technical Evaluation BULLISH

Since February, 2009, the technical indicators for TCLP have been BULLISH.

Insider Activity NA — UNFAVORABLE | NEUTRAL | FAVORABLE

Expanded Ratio Analysis

	2007	2006	2005	2004
Price/Sales	8.51	9.94	10.65	11.50
Price/EBITDA	9.06	10.38	NM	NM
Price/Pretax Income	13.14	14.09	11.29	12.00
P/E Ratio	13.14	14.09	11.29	12.00
Avg. Diluted Shares Outstg (M)	32.3	17.5	17.5	17.5

Figures based on calendar year-end price

Key Growth Rates and Averages

Past Growth Rate (%)	1 Year	3 Years	5 Years	9 Years
Sales	NM	32.16	18.56	NA
Net Income	99.11	14.14	9.10	NA
Ratio Analysis (Annual Avg.)				
Net Margin (%)	64.77	76.55	84.37	89.41
% LT Debt to Capitalization	38.72	33.05	21.67	14.18
Return on Equity (%)	14.78	15.44	16.54	15.45

Company Financials Fiscal Year Ended Dec. 31

Per Share Data ($)	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998
Tangible Book Value	23.48	12.84	17.23	16.85	15.77	15.31	14.92	14.30	14.33	NA
Cash Flow	2.95	2.57	2.87	3.15	2.74	2.50	2.40	2.08	1.13	NA
Earnings	2.51	2.39	2.70	2.99	2.63	2.50	2.40	2.08	1.13	NA
S&P Core Earnings	2.51	2.39	2.70	2.99	2.63	2.50	NA	NA	NA	NA
Dividends	2.56	2.33	2.30	2.25	2.15	2.05	1.95	1.83	0.62	NA
Payout Ratio	102%	97%	85%	75%	82%	82%	81%	88%	15%	NA
Prices:High	43.20	38.13	41.28	39.18	33.70	27.88	27.60	20.50	21.00	NA
Prices:Low	32.70	29.85	30.11	28.47	24.74	21.30	16.25	14.00	13.88	NA
P/E Ratio:High	17	16	15	13	13	11	12	10	19	NA
P/E Ratio:Low	13	12	11	10	9	9	7	7	12	NA

Income Statement Analysis (Million $)	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998
Revenue	137	63.4	53.2	57.5	49.8	47.5	45.7	39.1	20.9	NA
Operating Income	129	60.7	NM	NM	NM	NM	NM	NM	NM	NA
Depreciation	6.30	0.20	Nil	Nil	Nil	Nil	NM	Nil	Nil	NA
Interest Expense	35.6	15.8	1.00	0.50	0.10	0.50	0.97	0.50	Nil	NA
Pretax Income	89.0	44.7	50.2	55.1	48.0	45.5	43.5	37.2	20.2	NA
Effective Tax Rate	NM	NM	NM	NM	NM	Nil	Nil	Nil	Nil	NA
Net Income	89.0	44.7	50.2	55.1	48.0	45.5	43.5	37.2	20.2	NA
S&P Core Earnings	89.0	44.7	50.2	55.1	48.0	45.5	NA	NA	NA	NA

Balance Sheet & Other Financial Data (Million $)	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998
Cash	6.80	4.00	2.30	2.50	7.50	6.40	9.19	1.57	0.80	NA
Current Assets	11.0	6.50	316	2.50	7.50	6.40	9.19	1.57	0.80	NA
Total Assets	1,493	778	316	332	288	286	289	278	251	NA
Current Liabilities	13.8	9.30	14.1	7.20	6.10	0.60	0.48	0.64	0.41	NA
Long Term Debt	569	463	Nil	30.0	Nil	11.5	21.5	21.5	Nil	NA
Common Equity	900	304	302	295	282	274	267	255	251	NA
Total Capital	1,469	767	302	325	282	285	288	277	251	NA
Capital Expenditures	13.2	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	NA
Cash Flow	95.3	44.9	50.2	55.1	48.0	45.5	43.5	37.2	20.2	NA
Current Ratio	0.8	0.7	22.4	0.3	1.2	10.7	19.0	2.4	1.9	NA
% Long Term Debt of Capitalization	38.7	60.4	Nil	9.2	Nil	4.0	7.5	7.8	Nil	NA
% Net Income of Revenue	64.8	70.5	94.3	95.8	NM	NM	NM	NM	NM	NA
% Return on Assets	7.8	8.2	15.5	17.8	16.7	15.9	15.4	14.1	8.2	NA
% Return on Equity	14.8	14.7	16.8	19.1	17.3	16.8	16.7	14.7	8.2	NA

Data as orig reptd.; bef. results of disc opers/spec. items. Per share data adj. for stk. divs.; EPS diluted. E-Estimated. NA-Not Available. NM-Not Meaningful. NR-Not Ranked. UR-Under Review.

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TC PipeLines LP

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Sub-Industry Outlook

Our fundamental outlook for the oil and gas storage and transportation sub-industry for the next 12 months is neutral. We expect fee-based pipeline and terminal operators to continue to expand earnings well in excess of anticipated real U.S. GDP growth in 2008 and 2009. As of January, S&P estimated a 1.1% increase in U.S. real GDP for 2008 and a 2.0% decline for 2009, compared to the 2.0% rise in 2007. However, we believe that investors are concerned that the tightening credit market may hinder MLPs from raising capital to fund their expansion projects. In response to the poor credit environment and weak economy, many MLPs plan to reduce their capital expansion budgets for 2009 to preserve capital and maintain their dividends.

We believe that 2009 will be a volatile year for tanker companies. Based on industry research group Bassoe, daily spot charter rates for VLCCs were $66,000 in the fourth quarter of 2008, below the $91,000 average in the third quarter. We expect tanker rates to continue to soften in 2009, due to the expected increase in the worldwide fleet, cuts in OPEC production, and the slowing global economy. The shipping industry suffered from increased piracy in 2008. If piracy is not curtailed, many shippers will re-route their vessels, leading to longer and more expensive trips, in our opinion.

As of early January 2009, the Energy Information Administration (EIA) estimated that U.S. petroleum consumption declined 5.7% in 2008 and would fall another 2.0% in 2009, after being little changed in 2007. The EIA also estimated that natural gas consumption would increase 0.7% in 2008 and decline 1.0% in 2009. Longer term, we think drivers for new transportation infrastructure include new import terminals for liquefied natural gas, transcontinental movement of gas from the Rockies to Northeast markets, and increased oil sands production in Alberta. In our view, an active merger and acquisition environment will also remain a principal investor focus. Current yields as of February 3, 2009, on our universe of MLPs averaged about 11.0%, above the benchmark 10-year Treasury note, which was yielding about 2.83% at that time.

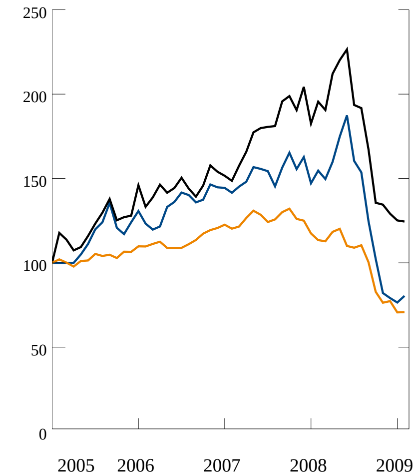
Year to date through February 2, the S&P Oil and Gas Storage and Transportation Index rose 1.1%, versus a 8.6% decline for the S&P 1500. In 2008, the S&P Oil and Gas Storage and Transportation Index was down 10.5%, versus a 38.2% decline for the S&P 1500. Our preference is for those issues with the potential to increase cash flow and dividend payouts over time.

--T. Shafi

Stock Performance

GICS Sector: Energy
Sub-Industry: Oil & Gas Storage & Transportation

Based on S&P 1500 Indexes
Month-end Price Performance as of 01/30/09



NOTE: All Sector & Sub-Industry information is based on the Global Industry Classification Standard (GICS)

Sub-Industry : Oil & Gas Storage & Transportation Peer Group*: Midstream Energy - Master Limited Partnership

Peer Group	Stock Symbol	Stk.Mkt. Cap. (Mil. $)	Recent Stock Price($)	52 Week High/Low($)	Beta	Yield (%)	P/E Ratio	Fair Value Calc.($)	Quality Ranking	S&P IQ %ile	Return on Revenue (%)	LTD to Cap (%)
TC Pipelines L.P.	**TCLP**	**882**	**25.29**	**37.29/18.11**	**0.75**	**11.2**	**9**	**27.10**	**NR**	**79**	**64.8**	**38.7**
Atlas Pipeline Ptnrs LP	APL	317	6.90	45.10/4.68	1.30	22.0	NM	NA	NR	20	NM	49.1
Buckeye Ptnrs L.P.	BPL	2,001	41.37	51.09/22.00	0.08	8.6	13	38.60	NR	70	29.9	43.3
Copano Energy L.L.C.	CPNO	799	16.53	39.75/8.80	1.45	13.9	14	NA	NR	23	5.5	41.3
Enbridge Energy Ptnrs L.P.	EEP	1,865	31.16	53.45/22.33	0.36	12.7	9	31.10	NR	50	3.0	53.8
Holly Energy Ptnrs L.P.	HEP	466	28.52	47.03/14.93	0.41	10.7	21	NA	NR	34	21.5	NA
Kinder Morgan Egy Ptnrs L.P.	KMP	9,057	50.58	60.89/35.59	0.17	8.3	25	44.70	NR	70	11.3	56.6
Magellan Midstream Hldgs L.P.	MGG	1,034	16.51	25.96/11.28	0.39	8.7	12	NA	NR	60	7.1	NA
Magellan Midstream Partners L.P.	MMP	2,369	35.49	45.00/18.85	0.05	8.0	11	32.10	NR	91	28.6	NA
MarkWest Energy Ptnrs L.P.	MWE	672	11.87	38.50/6.55	0.62	21.6	14	NA	NR	78	2.6	47.5
NuStar Energy L.P.	NS	2,646	48.58	55.11/27.00	0.03	8.7	12	43.20	NR	94	5.3	NA
ONEOK Partners L.P.	OKS	2,561	47.06	64.87/35.61	0.45	9.2	8	41.90	NR	94	7.0	54.2
Plains All Amer Pipeline LP	PAA	4,912	39.96	50.96/23.25	0.51	8.8	15	36.10	NR	88	1.4	47.9
Sunoco Logistics Ptnrs LP	SXL	1,576	54.98	56.00/27.62	0.25	7.2	11	NA	NR	92	2.1	46.6
Teppco Ptnrs L.P.	TPP	2,510	24.01	38.61/16.90	0.03	12.1	15	16.50	NR	53	2.9	54.4

NA-Not Available NM-Not Meaningful NR-Not Rated. *For Peer Groups with more than 15 companies or stocks, selection of issues is based on market capitalization.

Source: S&P.
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TC PipeLines LP

S&P Analyst Research Notes and other Company News

January 8, 2009
03:38 pm ET ... S&P MAINTAINS HOLD RECOMMENDATION ON LP UNITS OF TC PIPELINES (TCLP 25.07***): Ahead of Q4 results, we are reducing our Q4 earnings per unit forecast to $0.65 from $0.70, to reflect higher operating expenses expected in the company's Great Lakes segment. We see TCLP's Tuscarora segment benefiting from increased transmission revenues from a new contract in service. We are trimming our '09 earnings per unit estimate to $2.59 from $2.61 on weakening macro fundamentals. But we maintain our 12-month target price at $29, based on our targeted yield of 9.7% on estimated 12-month forward distributions. /T.Shafi

October 31, 2008
12:27 pm ET ... S&P MAINTAINS HOLD RECOMMENDATION ON SHARES OF LP UNITS OF TC PIPELINES (TCLP 26.27***): TCLP posts Q3 earnings per unit of $0.72 vs. $0.64, ahead of our $0.65 estimate. Equity income increases in the company's Northern Border and Tuscarora segments more than offset a decline in equity income from its Great Lakes segment. Financial charges were down in Q3 on declines in interest rates and average debt outstanding. Based on Q3 results, we are increasing our '08 earnings per unit to $2.78 from $2.71. We also raise our target price to $29 from $28, based on our targeted yield of 9.7% on estimated 12-month forward distributions. /T.Shafi

October 15, 2008
02:29 pm ET ... S&P MAINTAINS HOLD RECOMMENDATION ON SHARES OF LP UNITS OF TC PIPELINES (TCLP 24.8***): Ahead of Q3 report, we continue to forecast earnings per unit for the quarter at $0.65 vs. year-ago $0.64. We believe the company will benefit from improving income at its Tuscarora and Great Lakes pipelines interests. However, we do not expect the company's Northern Border segment to turn around in Q3, based on higher operating costs. We are maintaining our '08 earnings per unit estimate at $2.71. But we reduce our 12-month target price to $28 from $38, based on a target yield of 10% on our estimated 12-month forward distributions. /T.Shafi

July 31, 2008
11:17 am ET ... S&P MAINTAINS HOLD RECOMMENDATION ON LP UNITS OF TC PIPELINES (TCLP 34.66***): TCLP posts Q2 earnings per unit of $0.47 vs. $0.45, below our $0.57 estimate, reflecting lower revenues than we projected. Equity income for the company's Northern Border segment fell 16% to $8.7 million, reflecting lower transmission revenues. The company raised its second quarter cash distribution to $0.705 from year-earlier $0.655. Based on Q2 results, we are lowering our '08 earnings per unit to $2.71 from $2.81. We reduce our 12-month target price by $2 to $38, based on our targeted yield of 7.4% from estimated 12-month forward distributions. /T.Shafi

June 26, 2008
02:26 pm ET ... S&P MAINTAINS HOLD RECOMMENDATION ON SHARES OF LP UNITS OF TC PIPELINES (TCLP 35.68***): Ahead of Q2 results, we still see earnings per unit of $0.57 vs. year-ago $0.45. We believe that earnings will benefit from contributions from both TCLP's Northern Border Pipeline and Great Lakes operations, reflecting improving volumes. We also expect the Tuscarora pipeline expansion, which went into service on April 1, 2008, to add to revenue growth. We are maintaining our '08 earnings per unit estimate of $2.81. We are increasing our 12-month target price by $2 to $40, which is based on our targeted yield of 7.0% on estimated 12-month forward distributions. /T.Shafi

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TC PipeLines LP

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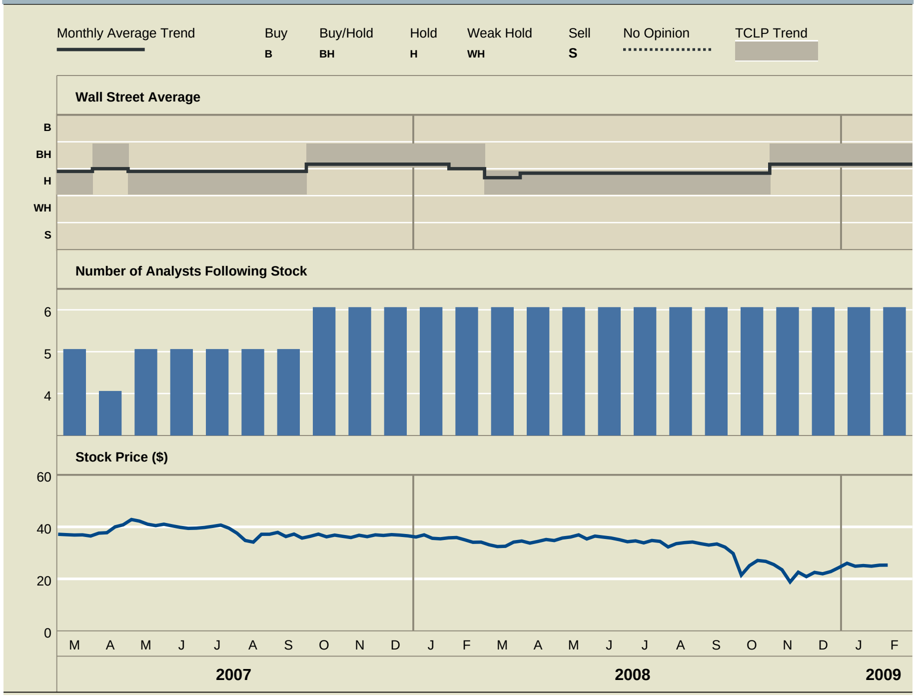
Analysts' Recommendations



Of the total 6 companies following TCLP, 6 analysts currently publish recommendations.

	No. of Ratings	% of Total	1 Mo. Prior	3 Mos. Prior
Buy	2	33	2	2
Buy/Hold	0	0	0	0
Hold	4	67	4	4
Weak Hold	0	0	0	0
Sell	0	0	0	0
No Opinion	0	0	0	0
Total	**6**	**100**	**6**	**6**

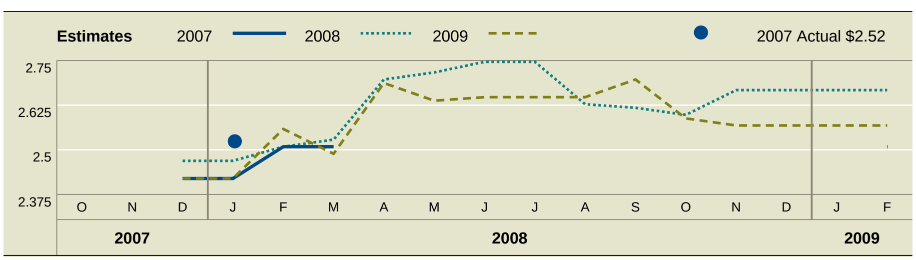
Wall Steet Consensus Opinion

BUY/HOLD

Companies Offering Coverage

Argus Research Corp.
Barclays Capital
Goldman Sachs & Co.
Merrill Lynch Research
Smith Barney
UBS Warburg

Wall Street Consensus Estimates



Fiscal Years	Avg Est.	High Est.	Low Est.	# of Est.	Est. P/E
2009	2.57	2.65	2.40	6	9.8
2008	2.67	2.73	2.60	4	9.5
2009 vs. 2008	▼ -4%	▼ -3%	▼ -8%	▲ 50%	▲ 3%
Q4'09	0.68	0.59	0.48	1	37.2
Q4'08	0.65	0.72	0.61	4	38.9
Q4'09 vs. Q4'08	▲ 5%	▼ -18%	▼ -21%	▼ -75%	▼ -4%

A company's earnings outlook plays a major part in any investment decision. Standard & Poor's organizes the earnings estimates of over 2,300 Wall Street analysts, and provides their consensus of earnings over the next two years. This graph shows the trend in analyst estimates over the past 15 months.

Wall Street Consensus vs. Performance

For fiscal year 2008, analysts estimate that TCLP will earn $2.67. For the 3rd quarter of fiscal year 2008, TCLP announced earnings per share of $0.72, representing 27% of the total annual estimate. For fiscal year 2009, analysts estimate that TCLP's earnings per share will decline by 4% to $2.57.

Source: S&P,I/B/E/S International, Inc.
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TC PipeLines LP

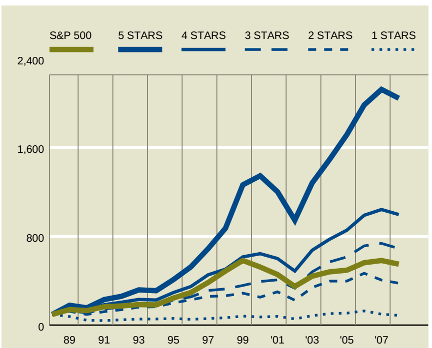
STANDARD &POOR'S

Glossary

S&P STARS

Since January 1, 1987, Standard and Poor's Equity Research Services has ranked a universe of common stocks based on a given stock's potential for future performance. Under proprietary STARS (STock Appreciation Ranking System), S&P equity analysts rank stocks according to their individual forecast of a stock's future total return potential versus the expected total return of a relevant benchmark (e.g., a regional index (S&P Asia 50 Index, S&P Europe 350 Index or S&P 500 Index)), based on a 12-month time horizon. STARS was designed to meet the needs of investors looking to put their investment decisions in perspective.

STARS Average Annual Performance



S&P 12-Month Target Price

The S&P equity analyst's projection of the market price a given security will command 12 months hence, based on a combination of intrinsic, relative, and private market valuation metrics.

Investment Style Classification

Characterizes the stock as Growth or Value, and indicates its capitalization level. Growth is evaluated along three dimensions (earnings, sales and internal growth), while Value is evaluated along four dimensions (book-to-price, cash flow-to-price, dividend yield and sale-to-price). Growth stocks score higher than the market average on growth dimensions and lower on value dimensions. The reverse is true for Value stocks. Certain stocks are classified as Blend, indicating a mixture of growth and value characteristics and cannot be classified as purely growth or value.

Qualitative Risk Assessment

The S&P equity analyst's view of a given company's operational risk, or the risk of a firm's ability to continue as an ongoing concern. The Qualitative Risk Assessment is a relative ranking to the S&P U.S. STARS universe, and should be reflective of risk factors related to a company's operations, as opposed to risk and volatility measures associated with share prices.

Quantitative Evaluations

In contrast to our qualitative STARS recommendations, which are assigned by S&P analysts, the quantitative evaluations described below are derived from proprietary arithmetic models. These computer-driven evaluations may at times contradict an analyst's qualitative assessment of a stock. One primary reason for this is that different measures are used to determine each. For instance, when designating STARS, S&P analysts assess many factors that cannot be reflected in a model, such as risks and opportunities, management changes, recent competitive shifts, patent expiration, litigation risk, etc.

S&P Quality Ranking

Growth and stability of earnings and dividends are deemed key elements in establishing S&P's Quality Rankings for common stocks, which are designed to capsulize the nature of this record in a single symbol. It should be noted, however, that the process also takes into consideration certain adjustments and modifications deemed desirable in establishing such rankings. The final score for each stock is measured against a scoring matrix determined by analysis of the scores of a large and representative sample of stocks. The range of scores in the array of this sample has been aligned with the following ladder of rankings:

A+	Highest	B	Below Average
A	High	B-	Lower
A-	Above Average	C	Lowest
B+	Average	D	In Reorganization
NR	Not Ranked		

S&P Fair Value Rank

Using S&P's exclusive proprietary quantitative model, stocks are ranked in one of five groups, ranging from Group 5, listing the most undervalued stocks, to Group 1, the most overvalued issues. Group 5 stocks are expected to generally outperform all others. A positive (+) or negative (-) Timing Index is placed next to the Fair Value ranking to further aid the selection process.A stock with a (+) added to the Fair Value Rank simply means that this stock has a somewhat better chance to outperform other stocks with the same Fair Value Rank. A stock with a (-) has a somewhat lesser chance to outperform other stocks with the same Fair Value Rank. The Fair Value rankings imply the following: 5-Stock is significantly undervalued; 4-Stock is moderately undervalued; 3-Stock is fairly valued; 2-Stock is modestly overvalued; 1-Stock is significantly overvalued.

S&P Fair Value Calculation

The price at which a stock should trade at, according to S&P's proprietary quantitative model that incorporates both actual and estimated variables (as opposed to only actual variables in the case of S&P Quality Ranking). Relying heavily on a company's actual return on equity, the S&P Fair Value model places a value on a security based on placing a formula-derived price-to-book multiple on a company's consensus earnings per share estimate.

Insider Activity

Gives an insight as to insider sentiment by showing whether directors, officers and key employees who have proprietary information not available to the general public, are buying or selling the company's stock during the most recent six months.

Funds From Operations FFO

FFO is Funds from Operations and equal to a REIT's net income, excluding gains or losses from sales of property, plus real estate depreciation.

Investability Quotient (IQ)

The IQ is a measure of investment desirability. It serves as an indicator of potential medium-to-long term return and as a caution against downside risk. The measure takes into account variables such as technical indicators, earnings estimates, liquidity, financial ratios and selected S&P proprietary measures.

S&P's IQ Rationale:
TC Pipelines L.P.

	Raw Score	Max Value
Proprietary S&P Measures	0	115
Technical Indicators	34	40
Liquidity/Volatility Measures	13	20
Quantitative Measures	67	75
IQ Total	**114**	**250**

Volatility

Rates the volatility of the stock's price over the past year.

Technical Evaluation

In researching the past market history of prices and trading volume for each company, S&P's computer models apply special technical methods and formulas to identify and project price trends for the stock.

Relative Strength Rank

Shows, on a scale of 1 to 99, how the stock has performed versus all other companies in S&P's universe on a rolling 13-week basis.

Global Industry Classification Standard (GICS)

An industry classification standard, developed by Standard & Poor's in collaboration with Morgan Stanley Capital International (MSCI). GICS is currently comprised of 10 Sectors, 24 Industry Groups, 68 Industries, and 154 Sub-Industries.

S&P Issuer Credit Rating

A Standard & Poor's Issuer Credit Rating is a current opinion of an obligor's overall financial capacity (its creditworthiness) to pay its financial obligations. This opinion focuses on the obligor's capacity and willingness to meet its financial commitments as they come due. It does not apply to any specific financial obligation, as it does not take into account the nature of and provisions of the obligation, its standing in bankruptcy or liquidation, statutory preferences, or the legality and enforceability of the obligation. In addition, it does not take into account the creditworthiness of the guarantors, insurers, or other forms of credit enhancement on the obligation. The Issuer Credit Rating is not a recommendation to purchase, sell, or hold a financial obligation issued by an obligor, as it does not comment on market price or suitability for a particular investor. Issuer Credit Ratings are based on current information furnished by obligors or obtained by Standard & Poor's from other sources it considers reliable. Standard & Poor's does not perform an audit in connection with any Issuer Credit Rating and may, on occasion, rely on unaudited financial information. Issuer Credit Ratings may be changed, suspended, or withdrawn as a result of changes in, or unavailability of, such information, or based on other circumstances.

Exchange Type

ASE - American Stock Exchange; NNM - Nasdaq National Market; NSC - Nasdaq SmallCap; NYSE - New York Stock Exchange; BB - OTC Bulletin Board; OT - Over-the-Counter; TO - Toronto Stock Exchange.

S&P Equity Research Services

Standard & Poor's Equity Research Services U.S. includes Standard & Poor's Investment Advisory Services LLC; Standard & Poor's Equity Research Services Europe includes Standard & Poor's LLC-London and Standard & Poor's AB (Sweden); Standard & Poor's Equity Research Services Asia includes Standard & Poor's LLC's offices in Hong Kong, Singapore and Tokyo, Standard & Poor's Malaysia Sdn Bhd, and Standard & Poor's Information Services (Australia) Pty Ltd.

Abbreviations Used in S&P Equity Research Reports

CAGR- Compound Annual Growth Rate; **CAPEX**- Capital Expenditures; **CY**- Calendar Year; **DCF**- Discounted Cash Flow; **EBIT**- Earnings Before Interest and Taxes; **EBITDA**- Earnings Before Interest, Taxes, Depreciation and Amortization; **EPS**- Earnings Per Share; **EV**- Enterprise Value; **FCF**- Free Cash Flow; **FFO**- Funds From Operations; **FY**- Fiscal Year; **P/E**- Price/Earnings ; **PEG Ratio**- P/E-to-Growth Ratio; **PV**- Present Value; **R&D**- Research & Development; **ROE**- Return on Equity; **ROI**- Return on Investment; **ROIC**- Return on Invested Capital; **ROA**- Return on Assets; **SG&A**- Selling, General & Administrative Expenses; **WACC**- Weighted Average Cost of Capital

Dividends on American Depository Receipts (ADRs) and American Depository Shares (ADSs) are net of taxes (paid in the country of origin).

Source: S&P.

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Required Disclosures

S&P Global STARS Distribution

In North America: As of December 31, 2008, research analysts at Standard & Poor's Equity Research Services U.S. have recommended 27.0% of issuers with buy recommendations, 61.2% with hold recommendations and 11.8% with sell recommendations.

In Europe: As of December 31, 2008, research analysts at Standard & Poor's Equity Research Services Europe have recommended 30.4% of issuers with buy recommendations, 45.3% with hold recommendations and 24.3% with sell recommendations.

In Asia: As of December 31, 2008, research analysts at Standard & Poor's Equity Research Services Asia have recommended 33.9% of issuers with buy recommendations, 54.4% with hold recommendations and 11.7% with sell recommendations.

Globally: As of December 31, 2008, research analysts at Standard & Poor's Equity Research Services globally have recommended 28.1% of issuers with buy recommendations, 58.3% with hold recommendations and 13.6% with sell recommendations.

★★★★★ **5-STARS (Strong Buy)**: Total return is expected to outperform the total return of a relevant benchmark, by a wide margin over the coming 12 months, with shares rising in price on an absolute basis.

★★★★☆ **4-STARS (Buy)**: Total return is expected to outperform the total return of a relevant benchmark over the coming 12 months, with shares rising in price on an absolute basis.

★★★☆☆ **3-STARS (Hold)**: Total return is expected to closely approximate the total return of a relevant benchmark over the coming 12 months, with shares generally rising in price on an absolute basis.

★★☆☆☆ **2-STARS (Sell)**: Total return is expected to underperform the total return of a relevant benchmark over the coming 12 months, and the share price not anticipated to show a gain.

★☆☆☆☆ **1-STARS (Strong Sell)**: Total return is expected to underperform the total return of a relevant benchmark by a wide margin over the coming 12 months, with shares falling in price on an absolute basis.

Relevant benchmarks: In North America the relevant benchmark is the S&P 500 Index, in Europe and in Asia, the relevant benchmarks are generally the S&P Europe 350 Index and the S&P Asia 50 Index.

For All Regions: All of the views expressed in this research report accurately reflect the research analyst's personal views regarding any and all of the subject securities or issuers. No part of analyst compensation was, is, or will be directly or indirectly, related to the specific recommendations or views expressed in this research report.

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STANDARD &POOR'S

Williams Cos Inc. (The)

S&P Recommendation HOLD ★★★★★	Price	12-Mo. Target Price	Investment Style
	$15.36 (as of Feb 13, 2009)	$17.00	Large-Cap Blend

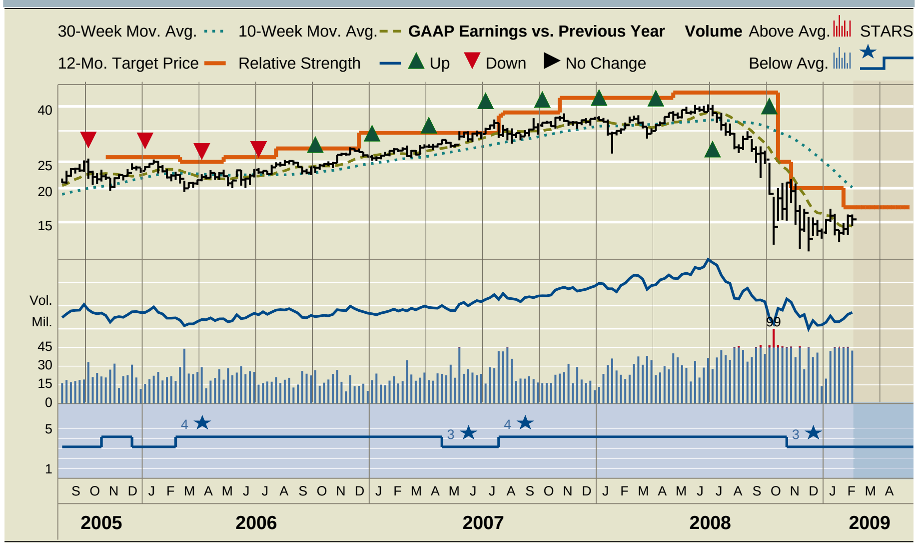
GICS Sector Energy
Sub-Industry Oil & Gas Storage & Transportation

Summary This Oklahoma-based company, which primarily finds, produces, gathers, processes and transports natural gas, also manages a wholesale power business.

Key Stock Statistics (Source S&P, Vickers, company reports)

52-Wk Range	$40.75– 11.69	S&P Oper. EPS 2008**E**	2.12	Market Capitalization(B)	$8.888	Beta	1.20
Trailing 12-Month EPS	$2.56	S&P Oper. EPS 2009**E**	1.38	Yield (%)	2.86	S&P 3-Yr. Proj. EPS CAGR(%)	1
Trailing 12-Month P/E	6.0	P/E on S&P Oper. EPS 2008**E**	7.2	Dividend Rate/Share	$0.44	S&P Credit Rating	BBB-
$10K Invested 5 Yrs Ago	$16,119	Common Shares Outstg. (M)	578.7	Institutional Ownership (%)	78		

Price Performance



Options: ASE, CBOE, P

Analysis prepared by **Michael Kay** on February 03, 2009, when the stock traded at **$ 13.75**.

Highlights

- We see production growth of 19% in 2008, but have reduced forecasts to 8% growth in 2009 as we assume lower capital spending due to weaker natural gas prices. Pipelines are seeing higher returns from the Transco system and Rockies capacity expansions. We expect E&P to benefit from the development of drilling prospects, especially in the Piceance and Powder River Basins, but we see lower prices impeding segment profits in 2009. WMB sees hurricane damage at midstream facilities cutting fourth quarter profit by $10-$20 million.
- Given volatile markets, we expect WMB to limit asset dropdowns into master limited partnerships Williams Partners (WPZ: $16) and Williams Pipeline Partners (WMZ: $16). WMB's capital budget for 2009 is $2.8-$3.1 billion, down from $3.375-$3.575 billion in 2008. We see E&P spending of about $1.3 billion in 2009, down from about $2 billion in 2008.
- We see 2008 EPS of $2.12, up 25%, on higher natural gas prices and NGL margins. We see lower NGL margins and natural gas prices leading to a 35% drop in 2009 EPS, to $1.38. In July 2008, WMB completed a $1 billion stock repurchase program.

Investment Rationale/Risk

- We expect WMB to expand drilling in the highly active Piceance Basin and the Barnett Shale, a significant inventory of acreage which, if developed, could boost proven reserves by well over 50%. We view positively WMB's stable fee-based business and regulated assets, rising oil and gas reserves, and what we view as its stable liquidity position. The company is evaluating structural changes to enhance shareholder value, and should have a specific plan early in 2009. WMB has noted the potential of splitting one or more of its primary business units.
- Risks to our recommendation and target price include sharply higher interest rates, slower than projected economic growth, a sustained decline in natural gas prices, and lower rates for FERC regulated pipelines.
- Given declining economic forecasts, and the ongoing credit crisis, we expect the market to discount unproven reserve potential, and we now value WMB on proven reserves. We also see lower company guidance for 2009. Our 12-month target price of $17 reflects an enterprise value to projected 2009 EBITDA multiple of 4.5X and our NAV based on WMB's proved reserves only of $20.

Qualitative Risk Assessment

LOW	MEDIUM	**HIGH**

Our risk assessment reflects our belief that although WMB has an E&P segment that can be very volatile, its business portfolio is overweighted in regulated industries with largely fixed returns.

Quantitative Evaluations

S&P Quality Ranking **B**

D	C	B-	**B**	B+	A-	A	A+

Relative Strength Rank **MODERATE**

63

LOWEST = 1 HIGHEST = 99

Revenue/Earnings Data

Revenue (Million $)

	1Q	2Q	3Q	4Q	Year
2008	3,224	3,729	3,267	--	--
2007	2,368	2,824	2,860	2,506	10,558
2006	3,028	2,715	3,300	2,770	11,813
2005	2,954	2,871	3,082	3,676	12,584
2004	3,070	3,052	3,375	2,964	12,461
2003	4,833	3,657	4,795	3,549	16,834

Earnings Per Share ($)

2008	0.70	0.70	0.63	**E**0.30	**E**2.12
2007	0.28	0.40	0.38	0.34	1.39
2006	0.22	-0.11	0.19	0.25	0.55
2005	0.34	0.07	0.01	0.12	0.53
2004	Nil	-0.03	0.03	0.17	0.18
2003	-0.09	0.17	0.04	-0.16	-0.03

Fiscal year ended Dec. 31. Next earnings report expected: Late February. EPS Estimates based on S&P Operating Earnings; historical GAAP earnings are as reported.

Dividend Data (Dates: mm/dd Payment Date: mm/dd/yy)

Amount ($)	Date Decl.	Ex-Div. Date	Stk. of Record	Payment Date
0.110	05/15	06/11	06/13	06/30/08
0.110	07/17	08/20	08/22	09/08/08
0.110	11/20	12/10	12/12	12/29/08
0.110	01/22	03/11	03/13	03/30/09

Dividends have been paid since 1974. Source: Company reports.

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Williams Cos Inc. (The)

STANDARD &POOR'S

Business Summary February 03, 2009

CORPORATE OVERVIEW. WMB primarily finds, produces, gathers, and processes and transports natural gas. Operations are concentrated in the Pacific Northwest, Rocky Mountains, Gulf Coast, Southern California and Eastern Seaboard.

In February 2003, WMB announced a business strategy focused on migrating to an integrated natural gas business comprised of a smaller portfolio of natural gas businesses, reducing debt and increasing liquidity via asset sales, strategic levels of financing, and reductions in operating costs.

CORPORATE STRATEGY. WMB has transitioned its corporate strategy toward aggressively focusing on the market in the segments in which it perceives a sustainable competitive advantage, primarily its exploration and production (E&P) segment and its midstream segment. WMB has about 4.14 Tcfe of proved reserves (99% natural gas, 54% proved developed), with natural gas produced from tight sands formations and coal bed methane reserves in the Piceance (69% of total reserves at December 31, 2007), San Juan (14%), Powder River (10%), Midcontinent and other basins (7%).

The midstream division provides natural gas gathering, processing and treating, and natural gas liquid fractionation, storage and marketing, with primary service areas concentrated in the western states of Wyoming, Colorado and New Mexico, and the onshore and offshore shelf and deepwater areas in and around the Gulf Coast states of Texas, Louisiana, Mississippi and Alabama. Geographically, midstream natural gas assets are positioned to maximize commercial and operational synergies with other WMB assets (e.g., offshore gathering and processing assets attach and process or condition natural gas supplies delivered to the Transco pipeline; WMB gathering and processing facilities in the San Juan basin handle about 80% of the group's wellhead production in the basin).

The gas pipeline division has 14,200 miles of pipeline, with total annual throughput of 2,700 trillion BTUs, including the Transcontinental Gas Pipeline (Transco) and the Northwest Pipeline. Each pipeline system operates under Federal Energy Regulatory Commission (FERC) approved tariffs that establish rates, cost recovery mechanisms, and service terms and conditions. The established rates are a function of WMB's cost of providing services, including a "reasonable" return on invested capital (ROIC).

IMPACT OF MAJOR DEVELOPMENTS. In June 2006, WMB reached an agreement in principle to settle class-action securities litigation filed on behalf of shareholders between July 24, 2000, and July 22, 2002, for a total payment of $290 million to plaintiffs. WMB funded $145 million of the settlement with cash on hand in November 2006, with the balance funded through insurance proceeds. WMB recorded a pretax charge of approximately $161 million in the second quarter of 2006.

In June 2006, Williams Partners L.P. (WPZ) acquired 25.1% of WMB's interest in Williams Four Corners LLC for $360 million. In December 2006, WPZ acquired the remaining 74.9% interest for $1.223 billion.

In January 2008, WMB announced it had placed an expansion of its Transco natural gas pipeline system into service, increasing transportation capacity into the New York City metropolitan area. The project required expanding certain existing Transco pipeline facilities in New Jersey, New York and Pennsylvania. This included adding approximately 12 miles of new 42-inch pipeline, replacing approximately 2.5 miles of existing 42-inch pipeline, adding a new compressor facility, and minor modifications to several other Transco facilities.

In March 2008, WMB and TransCanada Cop. (TRP) announced that they were evaluating the joint development of Sunstone Pipeline, a major new natural gas transmission pipeline that would move natural gas supply from the Rockies to markets in the western United States. The proposed Sunstone Pipeline is a 618-mile, 42-inch-diameter pipeline with capacity of up to 1.2 Bcfe/d. The project is proposed for service in 2011.

On July 21, 2008, WMB announced that it has agreed to purchase interests in north Texas' Barnett Shale for approximately $166 million cash. The parties expect the transaction to close in September. The assets represent an estimated 175 Bcfe of proved, probable and possible reserves on approximately 10,000 net acres. WMB has four drilling rigs operating in the Barnett Shale and plans to add two rigs in north Texas to begin developing the new acreage. The proposed acquisition also includes 41 existing producing wells with daily net production of approximately 9 MMcfe.

FINANCIAL TRENDS. We believe the company, particularly during the first three years of this decade, made missteps, mostly through an ill-advised aggressive investment in the merchant energy business. However, we think WMB correctly reassessed the relative merits of its portfolio businesses and has effectively executed its turnaround strategy thus far. In our opinion, WMB possesses a significant competitive advantage in its E&P segment by virtue of its landholdings in the Piceance Basin. WMB's business portfolio is dominated by asset-intensive and regulatory-influenced markets, which respond to strategies that lower capital costs. Its three-year average return on invested capital has been about 7%.

Corporate Information

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S.J. Malcolm

Pres
J.C. Bumgarner, Jr.

SVP & CFO
D.R. Chappel

SVP & General Counsel
J.J. Bender

Chief Admin Officer
R. Ewing

Board Members
J. R. Cleveland
K. B. Cooper
I. F. Engelhardt
W. R. Granberry
W. E. Green
J. H. Hinshaw
W. R. Howell
C. M. Lillis
G. A. Lorch
W. G. Lowrie
F. T. MacInnis
S. J. Malcolm
J. D. Stoney

Domicile
Delaware

Founded
1908

Employees
4,319

Stockholders
11,153

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Williams Cos Inc. (The)

STANDARD &POOR'S

Quantitative Evaluations

S&P Fair Value Rank 3+

1	2	3	4	5

LOWEST HIGHEST

Based on S&P's proprietary quantitative model, stocks are ranked from most overvalued (1) to most undervalued (5).

Fair Value Calculation $15.70 Analysis of the stock's current worth, based on S&P's proprietary quantitative model suggests that WMB is slightly undervalued by $0.34 or 2.2%.

Investability Quotient Percentile 70

LOWEST = 1 HIGHEST = 100

WMB scored higher than 70% of all companies for which an S&P Report is available.

Volatility LOW | AVERAGE | HIGH

Technical Evaluation NEUTRAL Since February, 2009, the technical indicators for WMB have been NEUTRAL.

Insider Activity UNFAVORABLE | NEUTRAL | FAVORABLE

Expanded Ratio Analysis

	2007	2006	2005	2004
Price/Sales	2.07	1.35	1.12	0.70
Price/EBITDA	7.43	7.49	7.12	4.59
Price/Pretax Income	14.94	27.45	25.20	35.48
P/E Ratio	25.76	47.77	44.23	93.62
Avg. Diluted Shares Outstg (M)	609.9	608.6	605.8	535.6

Figures based on calendar year-end price

Key Growth Rates and Averages

Past Growth Rate (%)	1 Year	3 Years	5 Years	9 Years
Sales	-10.62	-5.45	6.21	4.67
Net Income	NM	94.80	NM	31.96
Ratio Analysis (Annual Avg.)				
Net Margin (%)	8.02	4.45	2.84	2.57
% LT Debt to Capitalization	41.80	44.40	49.31	50.77
Return on Equity (%)	13.61	8.50	5.52	5.65

Company Financials Fiscal Year Ended Dec. 31

Per Share Data ($)	2007	2006	2005	2004	2003	2002	2001	2000	1999	1998
Tangible Book Value	9.51	8.48	7.70	7.06	5.96	7.15	9.43	13.26	11.69	8.34
Cash Flow	3.16	1.97	1.75	1.37	1.27	0.53	3.17	3.80	2.04	1.82
Earnings	1.39	0.55	0.53	0.18	-0.03	-1.14	1.67	1.95	0.36	0.32
S&P Core Earnings	1.41	0.78	0.64	0.05	-0.26	-1.34	1.40	NA	NA	NA
Dividends	0.39	0.35	0.25	0.08	0.04	0.42	0.68	0.60	0.60	0.60
Payout Ratio	28%	63%	47%	44%	NM	NM	41%	31%	167%	171%
Prices:High	37.74	28.32	25.72	17.18	10.73	26.35	46.44	49.75	53.75	36.94
Prices:Low	25.17	19.35	15.18	8.49	2.51	0.78	20.80	29.50	28.00	20.00
P/E Ratio:High	27	51	49	95	NM	NM	28	26	NM	NM
P/E Ratio:Low	18	35	29	47	NM	NM	12	15	NM	NM
Income Statement Analysis (Million $)										
Revenue	10,558	11,813	12,584	12,461	16,834	5,608	11,035	10,398	8,593	7,658
Operating Income	2,938	2,124	1,972	1,903	1,849	1,566	3,389	2,602	1,591	1,372
Depreciation	1,082	866	740	668	671	775	798	832	742	646
Interest Expense	685	659	664	833	1,241	1,325	747	1,010	668	515
Pretax Income	1,461	579	557	246	71.0	-617	1,533	1,415	316	247
Effective Tax Rate	35.9%	35.6%	38.4%	53.4%	51.3%	NM	41.1%	39.1%	51.0%	44.6%
Net Income	847	333	317	93.2	15.2	-502	835	873	162	147
S&P Core Earnings	852	480	388	27.3	-144	-699	703	NA	NA	NA
Balance Sheet & Other Financial Data (Million $)										
Cash	1,699	2,269	1,597	930	2,316	2,019	1,301	1,211	1,092	503
Current Assets	5,538	6,322	9,697	6,044	8,795	12,886	12,938	15,477	6,517	3,532
Total Assets	25,061	25,402	29,443	23,993	27,022	34,989	38,906	40,197	25,289	18,647
Current Liabilities	4,431	4,694	8,450	5,146	6,270	11,309	13,495	16,804	5,772	4,439
Long Term Debt	7,757	7,622	7,591	7,712	11,040	11,896	10,621	10,532	9,746	6,366
Common Equity	6,375	6,073	5,428	4,956	4,102	4,778	6,044	5,892	5,585	4,155
Total Capital	18,558	17,656	15,741	15,238	17,595	20,723	21,532	20,693	18,475	13,193
Capital Expenditures	2,816	-2,509	1,299	787	957	1,824	1,922	4,904	3,513	1,708
Cash Flow	1,929	1,198	1,057	762	657	274	1,633	1,705	901	786
Current Ratio	1.3	1.3	1.1	1.2	1.4	1.1	1.0	0.9	1.1	0.8
% Long Term Debt of Capitalization	41.8	43.2	48.2	50.6	62.7	57.4	49.3	50.9	52.8	48.3
% Net Income of Revenue	8.0	2.8	2.5	0.7	0.1	NM	7.6	8.4	1.9	1.9
% Return on Assets	3.4	1.2	1.2	0.4	0.0	NM	2.3	2.7	0.7	0.9
% Return on Equity	13.6	5.8	6.1	2.1	0.0	NM	14.0	15.2	3.3	3.7

Data as orig reptd.; bef. results of disc opers/spec. items. Per share data adj. for stk. divs.; EPS diluted. E-Estimated. NA-Not Available. NM-Not Meaningful. NR-Not Ranked. UR-Under Review.

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Williams Cos Inc. (The)

STANDARD &POOR'S

Sub-Industry Outlook

Our fundamental outlook for the oil and gas storage and transportation sub-industry for the next 12 months is neutral. We expect fee-based pipeline and terminal operators to continue to expand earnings well in excess of anticipated real U.S. GDP growth in 2008 and 2009. As of January, S&P estimated a 1.1% increase in U.S. real GDP for 2008 and a 2.0% decline for 2009, compared to the 2.0% rise in 2007. However, we believe that investors are concerned that the tightening credit market may hinder MLPs from raising capital to fund their expansion projects. In response to the poor credit environment and weak economy, many MLPs plan to reduce their capital expansion budgets for 2009 to preserve capital and maintain their dividends.

We believe that 2009 will be a volatile year for tanker companies. Based on industry research group Bassoe, daily spot charter rates for VLCCs were $66,000 in the fourth quarter of 2008, below the $91,000 average in the third quarter. We expect tanker rates to continue to soften in 2009, due to the expected increase in the worldwide fleet, cuts in OPEC production, and the slowing global economy. The shipping industry suffered from increased piracy in 2008. If piracy is not curtailed, many shippers will re-route their vessels, leading to longer and more expensive trips, in our opinion.

As of early January 2009, the Energy Information Administration (EIA) estimated that U.S. petroleum consumption declined 5.7% in 2008 and would fall another 2.0% in 2009, after being little changed in 2007. The EIA also estimated that natural gas consumption would increase 0.7% in 2008 and decline 1.0% in 2009. Longer term, we think drivers for new transportation infrastructure include new import terminals for liquefied natural gas, transcontinental movement of gas from the Rockies to Northeast markets, and increased oil sands production in Alberta. In our view, an active merger and acquisition environment will also remain a principal investor focus. Current yields as of February 3, 2009, on our universe of MLPs averaged about 11.0%, above the benchmark 10-year Treasury note, which was yielding about 2.83% at that time.

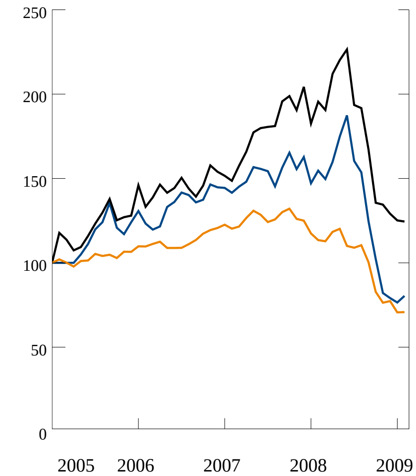
Year to date through February 2, the S&P Oil and Gas Storage and Transportation Index rose 1.1%, versus a 8.6% decline for the S&P 1500. In 2008, the S&P Oil and Gas Storage and Transportation Index was down 10.5%, versus a 38.2% decline for the S&P 1500. Our preference is for those issues with the potential to increase cash flow and dividend payouts over time.

--T. Shafi

Stock Performance

GICS Sector: Energy
Sub-Industry: Oil & Gas Storage & Transportation

Based on S&P 1500 Indexes
Month-end Price Performance as of 01/30/09



NOTE: All Sector & Sub-Industry information is based on the Global Industry Classification Standard (GICS)

Sub-Industry : Oil & Gas Storage & Transportation Peer Group*: Transportation & Storage

Peer Group	Stock Symbol	Stk.Mkt. Cap. (Mil. $)	Recent Stock Price($)	52 Week High/Low($)	Beta	Yield (%)	P/E Ratio	Fair Value Calc.($)	Quality Ranking	S&P IQ %ile	Return on Revenue (%)	LTD to Cap (%)
Williams Cos	**WMB**	**8,888**	**15.36**	**40.75/11.69**	**1.20**	**2.9**	**6**	**15.70**	**B**	**70**	**8.0**	**41.8**
Able Energy	ABLE	2	0.12	0.83/0.11	1.65	Nil	NM	NA	C	22	NM	21.0
Crosstex Energy	XTXI	147	3.18	37.00/2.07	2.30	11.3	4	NA	NR	1	0.3	82.6
El Paso Corp	EP	6,357	9.10	22.47/5.32	1.31	2.2	7	8.60	B-	49	9.4	64.1
Enbridge Energy Mgmt	EEQ	446	31.06	53.99/21.88	NA	12.6	15	31.40	NR	26	64.0	NA
Enbridge Inc	ENB	12,370	33.55	46.76/26.29	0.70	3.6	17	26.40	A	94	5.9	57.2
Kinder Morgan Mgmt LLC	KMR	3,379	44.25	57.32/34.01	0.36	Nil	33	37.40	NR	85	64.1	3.1
Penn Octane	POCC	21	1.39	2.70/1.20	0.20	Nil	NM	NA	C	6	NM	70.4
SMF Energy	FUEL	4	0.24	1.03/0.18	1.26	Nil	NM	NA	C	25	NM	74.2
TransCanada Corp	TRP	14,677	27.08	41.53/23.52	0.81	4.5	10	21.30	A-	66	13.9	54.3
World Pt. Terminals	WPO.C	285	11.75	16.00/8.00	NA	Nil	17	NA	NR	NA	24.7	9.5

NA-Not Available NM-Not Meaningful NR-Not Rated. *For Peer Groups with more than 15 companies or stocks, selection of issues is based on market capitalization.

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Williams Cos Inc. (The)

STANDARD &POOR'S

S&P Analyst Research Notes and other Company News

January 29, 2009
03:23 pm ET ... S&P MAINTAINS HOLD RECOMMENDATION ON SHARES OF WILLIAMS COS (WMB 14.36***): On lower crude oil and natural gas price forecasts, we are cutting our '08 EPS estimate by $0.15 to $2.12 and '09's by $0.64 to $1.38. Because of the challenging economic environment, WMB has suspended over $350M of potential projects. Also, it expects a $700M cut in '09 drilling capex, which has led us to lower our production growth rates. On revised relative metrics blended with our proved-reserve NAV estimate of $20, we cut our target price by $3 to $17. WMB is set to report Q4 and '08 results on 2/19, and we await updates on potential structural changes it is planning. /M. Kay

November 6, 2008
WMB posts lower-than-expected $0.62 vs. $0.33 Q3 EPS. Says it is now facing a more challenging environment. Separately, board says it evaluating structural changes in co. to enhance shareholder value; expects to announce a specific direction in Q1. Among potential changes is separation of one of more of co.'s principal business units.

November 6, 2008
12:35 pm ET ... S&P DOWNGRADES RECOMMENDATION ON SHARES OF WILLIAMS COS TO HOLD FROM BUY (WMB 18.9***): Q3 EPS of $0.57, before $0.05 derivative gain, vs. $0.39, is $0.08 below our view on profit miss in exploration & production segment. WMB is mulling possible split-up and should have plan by early '09, but we see near-term difficulty on current credit and equity markets. We see reduced '09 capex on lower oil and gas prices, and we cut our '08 EPS view $0.18 to $2.27 and '09's $0.36 to $2.02. On lower relative metrics blended with proven-reserve NAV, we cut our target price by $5 to $20 and downgrade on weakening forecasts and uncertainty with respect to split-up. /M.Kay

October 10, 2008
02:21 pm ET ... S&P MAINTAINS BUY RECOMMENDATION ON SHARES OF WILLIAMS COS (WMB 13.67****): We cut our '08 EPS view by $0.51 to $2.45 and '09's by $0.75 to $2.38, on lower price realization estimates. Shares are down close to 60% in '08, to about 1X the book value, amid exposure to gas prices and the high-debt nature of pipeline business. On a weaker price deck applied to our NAV estimate, now only using proved reserves added to the value of midstream operations, we cut our target price by $20 to $25. Despite the high-risk nature of current markets, we view WMB shares as attractive given the company's stable fee-based pipeline business and growing E&P assets. /M. Kay

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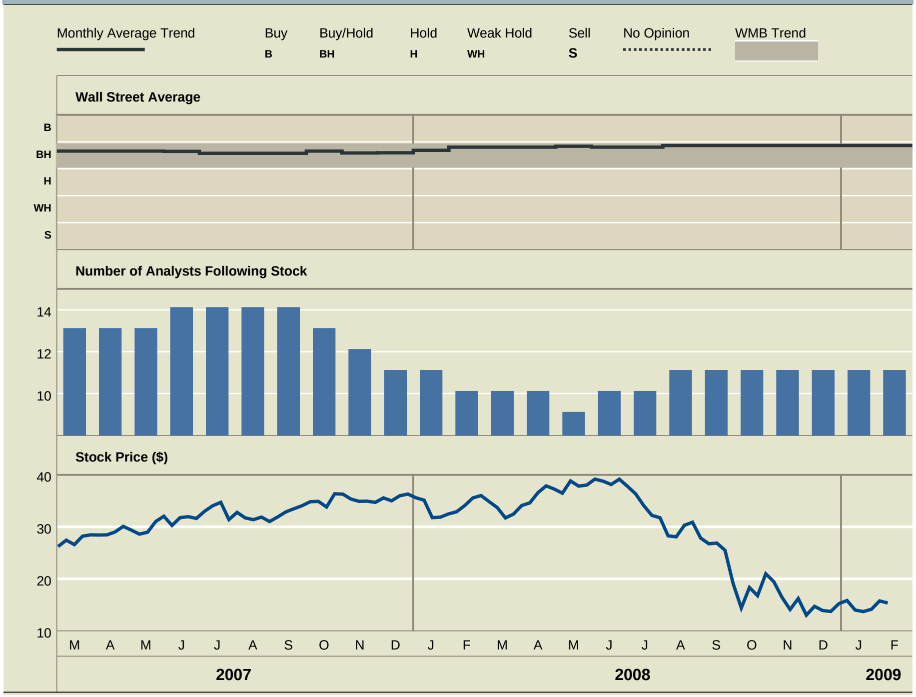
STANDARD &POOR'S

Williams Cos Inc. (The)

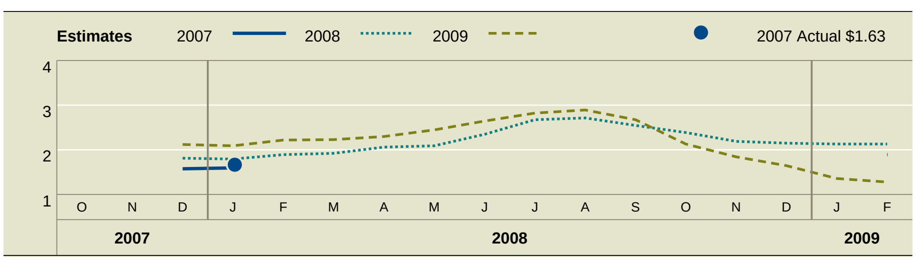
Analysts' Recommendations



Of the total 13 companies following WMB, 12 analysts currently publish recommendations.

	No. of Ratings	% of Total	1 Mo. Prior	3 Mos. Prior
Buy	5	42	5	5
Buy/Hold	4	33	5	5
Hold	2	17	1	1
Weak Hold	0	0	0	0
Sell	0	0	0	0
No Opinion	1	8	1	1
Total	**12**	**100**	**12**	**12**

Wall Street Consensus Estimates



Fiscal Years	Avg Est.	High Est.	Low Est.	# of Est.	Est. P/E
2009	1.28	2.45	0.90	12	12.0
2008	2.14	2.35	2.05	8	7.2
2009 vs. 2008	▼ -40%	▲ 4%	▼ -56%	▲ 50%	▲ 67%
Q4'09	0.37	0.35	0.26	4	41.5
Q4'08	0.30	0.36	0.23	10	51.2
Q4'09 vs. Q4'08	▲ 23%	▼ -3%	▲ 13%	▼ -60%	▼ -19%

A company's earnings outlook plays a major part in any investment decision. Standard & Poor's organizes the earnings estimates of over 2,300 Wall Street analysts, and provides their consensus of earnings over the next two years. This graph shows the trend in analyst estimates over the past 15 months.

Wall Steet Consensus Opinion

BUY/HOLD

Companies Offering Coverage

Argus Research Corp.
Barclays Capital
Calyon Securities (usa) Inc.
Harris Nesbitt
Howard Weil Labouisse Friedric
JP Morgan Securities
Pickering Energy Partners, Inc.
RBC Capital Markets (US)
Raymond James & Assoc, Inc.
Simmons & Company Int'l
Smith Barney
UBS Warburg
Wachovia Securities

Wall Street Consensus vs. Performance

For fiscal year 2008, analysts estimate that WMB will earn $2.14. For the 3rd quarter of fiscal year 2008, WMB announced earnings per share of $0.62, representing 29% of the total annual estimate. For fiscal year 2009, analysts estimate that WMB's earnings per share will decline by 40% to $1.28.

Source: S&P,I/B/E/S International, Inc.

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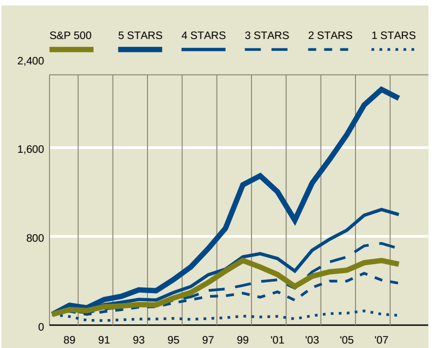
Williams Cos Inc. (The)

STANDARD &POOR'S

Glossary

S&P STARS
Since January 1, 1987, Standard and Poor's Equity Research Services has ranked a universe of common stocks based on a given stock's potential for future performance. Under proprietary STARS (STock Appreciation Ranking System), S&P equity analysts rank stocks according to their individual forecast of a stock's future total return potential versus the expected total return of a relevant benchmark (e.g., a regional index (S&P Asia 50 Index, S&P Europe 350 Index or S&P 500 Index)), based on a 12-month time horizon. STARS was designed to meet the needs of investors looking to put their investment decisions in perspective.

STARS Average Annual Performance



S&P 12-Month Target Price
The S&P equity analyst's projection of the market price a given security will command 12 months hence, based on a combination of intrinsic, relative, and private market valuation metrics.

Investment Style Classification
Characterizes the stock as Growth or Value, and indicates its capitalization level. Growth is evaluated along three dimensions (earnings, sales and internal growth), while Value is evaluated along four dimensions (book-to-price, cash flow-to-price, dividend yield and sale-to-price). Growth stocks score higher than the market average on growth dimensions and lower on value dimensions. The reverse is true for Value stocks. Certain stocks are classified as Blend, indicating a mixture of growth and value characteristics and cannot be classified as purely growth or value.

Qualitative Risk Assessment
The S&P equity analyst's view of a given company's operational risk, or the risk of a firm's ability to continue as an ongoing concern. The Qualitative Risk Assessment is a relative ranking to the S&P U.S. STARS universe, and should be reflective of risk factors related to a company's operations, as opposed to risk and volatility measures associated with share prices.

Quantitative Evaluations
In contrast to our qualitative STARS recommendations, which are assigned by S&P analysts, the quantitative evaluations described below are derived from proprietary arithmetic models. These computer-driven evaluations may at times contradict an analyst's qualitative assessment of a stock. One primary reason for this is that different measures are used to determine each. For instance, when designating STARS, S&P analysts assess many factors that cannot be reflected in a model, such as risks and opportunities, management changes, recent competitive shifts, patent expiration, litigation risk, etc.

S&P Quality Ranking
Growth and stability of earnings and dividends are deemed key elements in establishing S&P's Quality Rankings for common stocks, which are designed to capsulize the nature of this record in a single symbol. It should be noted, however, that the process also takes into consideration certain adjustments and modifications deemed desirable in establishing such rankings. The final score for each stock is measured against a scoring matrix determined by analysis of the scores of a large and representative sample of stocks. The range of scores in the array of this sample has been aligned with the following ladder of rankings:

A+	Highest	B	Below Average
A	High	B-	Lower
A-	Above Average	C	Lowest
B+	Average	D	In Reorganization
NR	Not Ranked		

S&P Fair Value Rank
Using S&P's exclusive proprietary quantitative model, stocks are ranked in one of five groups, ranging from Group 5, listing the most undervalued stocks, to Group 1, the most overvalued issues. Group 5 stocks are expected to generally outperform all others. A positive (+) or negative (-) Timing Index is placed next to the Fair Value ranking to further aid the selection process.A stock with a (+) added to the Fair Value Rank simply means that this stock has a somewhat better chance to outperform other stocks with the same Fair Value Rank. A stock with a (-) has a somewhat lesser chance to outperform other stocks with the same Fair Value Rank. The Fair Value rankings imply the following: 5-Stock is significantly undervalued; 4-Stock is moderately undervalued; 3-Stock is fairly valued; 2-Stock is modestly overvalued; 1-Stock is significantly overvalued.

S&P Fair Value Calculation
The price at which a stock should trade at, according to S&P's proprietary quantitative model that incorporates both actual and estimated variables (as opposed to only actual variables in the case of S&P Quality Ranking). Relying heavily on a company's actual return on equity, the S&P Fair Value model places a value on a security based on placing a formula-derived price-to-book multiple on a company's consensus earnings per share estimate.

Insider Activity
Gives an insight as to insider sentiment by showing whether directors, officers and key employees who have proprietary information not available to the general public, are buying or selling the company's stock during the most recent six months.

Funds From Operations FFO
FFO is Funds from Operations and equal to a REIT's net income, excluding gains or losses from sales of property, plus real estate depreciation.

Investability Quotient (IQ)
The IQ is a measure of investment desirability. It serves as an indicator of potential medium-to-long term return and as a caution against downside risk. The measure takes into account variables such as technical indicators, earnings estimates, liquidity, financial ratios and selected S&P proprietary measures.

S&P's IQ Rationale:
Williams Cos

	Raw Score	Max Value
Proprietary S&P Measures	54	115
Technical Indicators	26	40
Liquidity/Volatility Measures	16	20
Quantitative Measures	8	75
IQ Total	**104**	**250**

Volatility
Rates the volatility of the stock's price over the past year.

Technical Evaluation
In researching the past market history of prices and trading volume for each company, S&P's computer models apply special technical methods and formulas to identify and project price trends for the stock.

Relative Strength Rank
Shows, on a scale of 1 to 99, how the stock has performed versus all other companies in S&P's universe on a rolling 13-week basis.

Global Industry Classification Standard (GICS)
An industry classification standard, developed by Standard & Poor's in collaboration with Morgan Stanley Capital International (MSCI). GICS is currently comprised of 10 Sectors, 24 Industry Groups, 68 Industries, and 154 Sub-Industries.

S&P Issuer Credit Rating
A Standard & Poor's Issuer Credit Rating is a current opinion of an obligor's overall financial capacity (its creditworthiness) to pay its financial obligations. This opinion focuses on the obligor's capacity and willingness to meet its financial commitments as they come due. It does not apply to any specific financial obligation, as it does not take into account the nature of and provisions of the obligation, its standing in bankruptcy or liquidation, statutory preferences, or the legality and enforceability of the obligation. In addition, it does not take into account the creditworthiness of the guarantors, insurers, or other forms of credit enhancement on the obligation. The Issuer Credit Rating is not a recommendation to purchase, sell, or hold a financial obligation issued by an obligor, as it does not comment on market price or suitability for a particular investor. Issuer Credit Ratings are based on current information furnished by obligors or obtained by Standard & Poor's from other sources it considers reliable. Standard & Poor's does not perform an audit in connection with any Issuer Credit Rating and may, on occasion, rely on unaudited financial information. Issuer Credit Ratings may be changed, suspended, or withdrawn as a result of changes in, or unavailability of, such information, or based on other circumstances.

Exchange Type
ASE - American Stock Exchange; NNM - Nasdaq National Market; NSC - Nasdaq SmallCap; NYSE - New York Stock Exchange; BB - OTC Bulletin Board; OT - Over-the-Counter; TO - Toronto Stock Exchange.

S&P Equity Research Services
Standard & Poor's Equity Research Services U.S. includes Standard & Poor's Investment Advisory Services LLC; Standard & Poor's Equity Research Services Europe includes Standard & Poor's LLC-London and Standard & Poor's AB (Sweden); Standard & Poor's Equity Research Services Asia includes Standard & Poor's LLC's offices in Hong Kong, Singapore and Tokyo, Standard & Poor's Malaysia Sdn Bhd, and Standard & Poor's Information Services (Australia) Pty Ltd.

Abbreviations Used in S&P Equity Research Reports
CAGR- Compound Annual Growth Rate; **CAPEX**- Capital Expenditures; **CY**- Calendar Year; **DCF**- Discounted Cash Flow; **EBIT**- Earnings Before Interest and Taxes; **EBITDA**- Earnings Before Interest, Taxes, Depreciation and Amortization; **EPS**- Earnings Per Share; **EV**- Enterprise Value; **FCF**- Free Cash Flow; **FFO**- Funds From Operations; **FY**- Fiscal Year; **P/E**- Price/Earnings ; **PEG Ratio**- P/E-to-Growth Ratio; **PV**- Present Value; **R&D**- Research & Development; **ROE**- Return on Equity; **ROI**- Return on Investment; **ROIC**- Return on Invested Capital; **ROA**- Return on Assets; **SG&A**- Selling, General & Administrative Expenses; **WACC**- Weighted Average Cost of Capital

Dividends on American Depository Receipts (ADRs) and American Depository Shares (ADSs) are net of taxes (paid in the country of origin).

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Williams Cos Inc. (The)

STANDARD &POOR'S

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S&P Global STARS Distribution

In North America: As of December 31, 2008, research analysts at Standard & Poor's Equity Research Services U.S. have recommended 27.0% of issuers with buy recommendations, 61.2% with hold recommendations and 11.8% with sell recommendations.

In Europe: As of December 31, 2008, research analysts at Standard & Poor's Equity Research Services Europe have recommended 30.4% of issuers with buy recommendations, 45.3% with hold recommendations and 24.3% with sell recommendations.

In Asia: As of December 31, 2008, research analysts at Standard & Poor's Equity Research Services Asia have recommended 33.9% of issuers with buy recommendations, 54.4% with hold recommendations and 11.7% with sell recommendations.

Globally: As of December 31, 2008, research analysts at Standard & Poor's Equity Research Services globally have recommended 28.1% of issuers with buy recommendations, 58.3% with hold recommendations and 13.6% with sell recommendations.

★★★★★ **5-STARS (Strong Buy)**: Total return is expected to outperform the total return of a relevant benchmark, by a wide margin over the coming 12 months, with shares rising in price on an absolute basis.

★★★★☆ **4-STARS (Buy)**: Total return is expected to outperform the total return of a relevant benchmark over the coming 12 months, with shares rising in price on an absolute basis.

★★★☆☆ **3-STARS (Hold)**: Total return is expected to closely approximate the total return of a relevant benchmark over the coming 12 months, with shares generally rising in price on an absolute basis.

★★☆☆☆ **2-STARS (Sell)**: Total return is expected to underperform the total return of a relevant benchmark over the coming 12 months, and the share price not anticipated to show a gain.

★☆☆☆☆ **1-STARS (Strong Sell)**: Total return is expected to underperform the total return of a relevant benchmark by a wide margin over the coming 12 months, with shares falling in price on an absolute basis.

Relevant benchmarks: In North America the relevant benchmark is the S&P 500 Index, in Europe and in Asia, the relevant benchmarks are generally the S&P Europe 350 Index and the S&P Asia 50 Index.

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THOMSON FINANCIAL

Thomson Reuters Company in Context Report

- Updated January 13, 2009

BOARDWALK PIPELINE PARTNERS, LP (BWP-N)

OIL & GAS / OIL EQUIP. & SERVICES / PIPELINES

Gradient Opinion

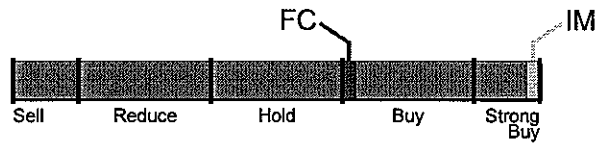
The Gradient Opinion, provided by Gradient Analytics Inc, is an empirically-derived and historically back-tested stock rating system with buy, sell, and hold opinions. To develop a rating the quantitative system analyzes a firm's earnings quality, balance sheet, and income statement, conducts technical and valuation analysis and evaluates the transactions made by the company's management and directors (i.e. insiders).

Gradient Analytics, Inc is a private independent research firm specializing in engineering institutional stock rating systems.

Analyst Recommendations

First Call Mean (FC): **Buy** (12 firms)

Independent Mean (IM): **Strong Buy** (1 firms)

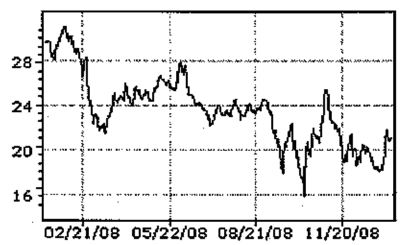


First Call Mean (FC) is the mean recommendation of all analysts covering the stock. Independent Mean (IM) is the mean recommendation of only independent analysts, which includes quantitative firms that are not included in the FC mean.

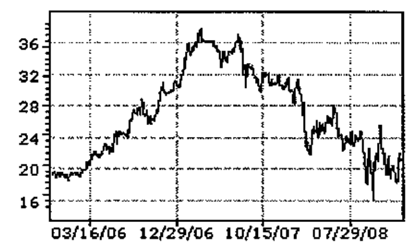
Key Information

Price (01/12/09)	$20.23
52-Week High	$31.83
52-Week Low	$14.00
Market Cap	$2.1B
Avg Daily Vol	560,200
Exchange	NYSE
Dividend Yield	9.4%
Annual Dividend	$1.90
P/E Cur Yr (12/08)	11.9
P/E Next Yr (12/09)	11.6
Forward PEG	1.5
LTG Forecast	8.4%
Exp Report Date	02/16/09
Annual Revenue	$652M
ROE	13.4%
Inst. Ownership	>100%

1-Year Price Chart



5-Year Price Chart



Business Description

Boardwalk Pipeline Partners, LP. The Group's principal activities include transportation, gathering and storage of natural gas. It owns and operates two interstate natural gas pipeline systems, with approximately 13,550 miles of pipeline, directly serving customers in 11 states and indirectly serving customers throughout the northeastern and southeastern United States through interconnections with unaffiliated pipelines. It transports and stores natural gas for local gas distribution companies (LDCs), municipalities, interstate and intrastate pipelines, direct industrial users, electric power generators, marketers and producers

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THOMSON FINANCIAL

Thomson Reuters Company in Context Report for BWP

- Updated January 13, 2009

Peer Analysis

Ticker	Gradient Opinion	Price (01/09/09)	Market Cap	Dividend Yield	P/E Current Year	P/E Next Year	LTG Forecast	Annual Revenue	Net Margin	1-Mo Return	3-Mo Return	1-Yr Return
NS	Buy	$44.88	$2.5B	9.2%	11.2	11.5	6.5%	$4.3B	7.8%	6.0%	45.3%	-18.1%
TPP	Hold	$23.14	$2.5B	12.2%	12.6	12.2	7.8%	$12.6B	0.9%	16.1%	17.5%	-39.4%
EPE	Hold	$19.45	$2.4B	9.2%	12.6	12.5	7.5%	$37.9B	0.4%	3.8%	19.9%	-44.3%
OGE	Hold	$24.76	$2.3B	5.7%	9.8	9.8	6.0%	$4.3B	11.1%	0.5%	14.6%	-30.5%
MMP	Hold	$32.09	$2.2B	8.5%	10.8	10.6	6.1%	$1.3B	17.2%	4.1%	44.9%	-26.2%
BWP	**Buy**	**$20.23**	**$2.1B**	**9.1%**	**11.9**	**11.6**	**8.4%**	**$652M**	**43.0%**	**3.8%**	**32.1%**	**-32.6%**
BPL	--	$36.44	$1.8B	9.6%	11.9	11.4	3.3%	$1.1B	6.9%	6.7%	41.9%	-25.9%
EEP	Hold	$28.56	$1.7B	13.6%	9.3	10.5	3.5%	$10.3B	3.7%	2.5%	5.5%	-44.1%
SXL	Hold	$48.67	$1.4B	7.8%	10.7	10.8	3.7%	$9.9B	1.0%	11.1%	67.2%	-0.7%
EPB	--	$16.15	$1.4B	7.3%	13.8	12.0	10.1%	$132M	58.8%	9.9%	25.4%	-33.1%
MGG	Hold	$16.16	$1.0B	8.6%	12.7	12.3	10.0%	$1.3B	6.2%	9.5%	15.4%	-36.9%
Average	--	--	$1.9M	9.3%	11.6	11.4	6.6%	$7.6B	14.3%	6.7%	30.0%	-30.2%
Median	--	--	$2.1M	9.0%	11.9	11.5	6.5%	$4.3B	6.9%	6.0%	25.4%	-32.6%

Peer Group

NS	NUSTAR ENERGY L P
TPP	TEPPCO PARTNERS, L.P.
EPE	ENTERPRISE GP HOLDINGS L.P.
OGE	OGE ENERGY CORPORATION
MMP	MAGELLAN MIDSTREAM PARTNERS, L.P.
BPL	BUCKEYE PARTNERS, L.P.
EEP	ENBRIDGE ENERGY PARTNERS LP
SXL	SUNOCO LOGISTICS PARTNERS LP
EPB	EL PASO PIPELINE PARTNERS, L.P.
MGG	MAGELLAN MIDSTREAM HOLDINGS, L.P.

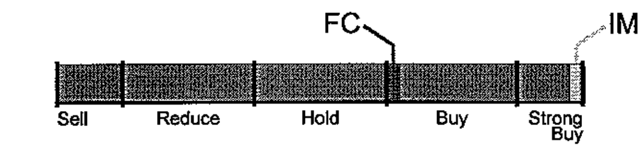
Earnings Highlights

- BWP's current quarter consensus estimate has decreased over the past 90 days from $0.41 to $0.39, a loss of -4.4%. Consensus estimates for the Pipelines Subsector have moved an average -8.0% during the same time period.
- Over the past 90 days, the consensus price target for BWP has decreased notably from $28.50 to $25.30, a loss of -11.2%.
- During the past four weeks, analysts covering BWP have made no upward or downward EPS estimate revisions for the current quarter.

Analyst Recommendations

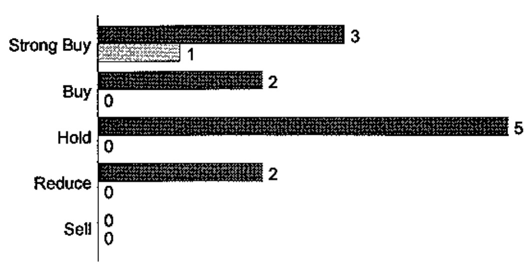
First Call Mean (FC): Buy (12 firms)

Independent Mean (IM): Strong Buy (1 firms)



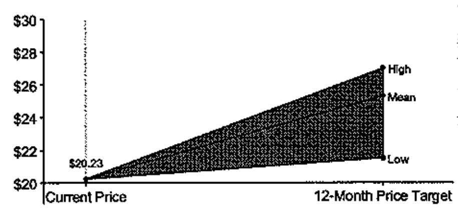
Distribution

Analysts typically rate a stock based on a five-tier scale ranging from 'Strong Buy' to 'Sell'. The chart below displays the number of analysts in each tier.



Price Target

The chart below indicates where analysts predict the stock price will be within the next 12 months, as compared to the curent price. The high, low, and mean price targets are presented.



12-Month Price Target	
Mean	$25.30
High	$27.00
Low	$21.50
Target vs. Current	25.1%
# of Analysts	8

Mean Estimate Trend

	Q 12-08	Q 03-09	Y 2008	Y 2009	Price Target
Current	$0.39	$0.45	$1.76	$1.81	$25.30
30 Days Ago	$0.40	$0.45	$1.76	$1.82	$25.50
90 Days Ago	$0.41	$0.54	$1.67	$1.96	$28.50
% Change - Last 90 Days	-4.4%	-16.8%	4.8%	-7.5%	-11.2%

Next Expected Report Date: 02/16/09

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THOMSON FINANCIAL

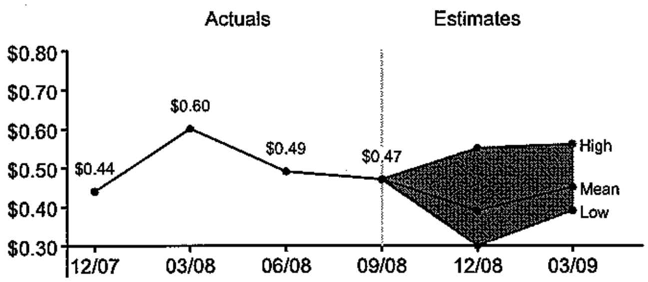
Thomson Reuters Company in Context Report for BWP

- Updated January 13, 2009

Earnings Per Share

Earnings per share (EPS) is calculated by dividing a company's earnings by the number of shares outstanding. Analysts tend to interpret a pattern of increasing earnings as a sign of strength and flat or falling earnings as a sign of weakness. The charts below provide a comparison between a company's actual and estimated EPS, including the high and low forecasts.

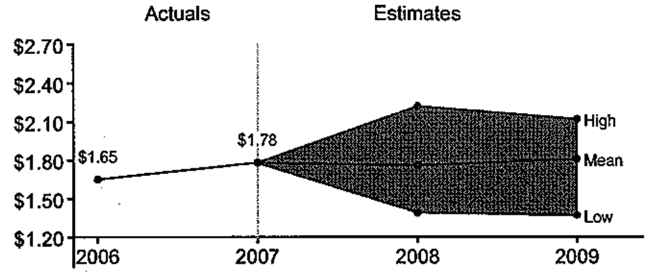
Quarterly



Estimates	12-08	03-09
FC Mean	$0.39	$0.45
High	$0.55	$0.56
Low	$0.30	$0.39
# of Analysts	10	6

NA = No Actual or Estimated EPS

Annual



Estimates	2008	2009
FC Mean	$1.76	$1.81
High	$2.22	$2.12
Low	$1.39	$1.37
# of Analysts	11	10

NA = No Actual or Estimated EPS

Earnings Surprise

Investors frequently compare a company's actual earnings to the mean expectation of professional analysts. The difference between the two is referred to as a "positive" or "negative" surprise. Academic research has shown that when a company reports a surprise, it is often followed by more of the same surprise type.

Surprise Summary - Last 3 Years

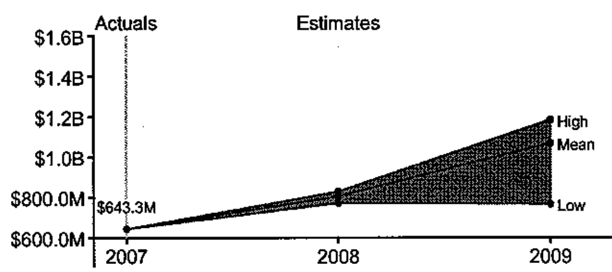
Surprise Type	#	%
Positive Quarters (> 2%)	10	83.3%
Negative Quarters (< -2%)	1	8.3%
In-Line Quarters (within 2%)	1	8.3%

Surprise Detail - Last 6 Periods

Surprise Type	Announce Date	Period End Date	Actual EPS	Mean EPS	Surprise (%)
POSITIVE	10/27/08	09/08	$0.470	$0.288	63.2%
POSITIVE	07/28/08	06/08	$0.490	$0.328	49.4%
POSITIVE	04/28/08	03/08	$0.600	$0.578	3.8%
NEGATIVE	02/11/08	12/07	$0.440	$0.576	-23.6%
POSITIVE	10/29/07	09/07	$0.310	$0.285	8.8%
POSITIVE	07/30/07	06/07	$0.420	$0.250	68.0%

Annual Revenue

A pattern of increasing sales in conjunction with a rising EPS may influence a buy recommendation, while flat or falling sales and faltering earnings may explain a sell recommendation. A rising EPS with flat or falling sales may result from increased cost efficiency and margins, rather than market expansion. This chart shows the revenue forecast trend of all analysts and the highest and lowest projections for the current and next fiscal year.



	2008	2009
Mean	$805M	$1.1B
High	$829M	$1.2B
Low	$773M	$766M
Forecasted Growth	25.1%	66.2%
# of Analysts	6	6

NA = No Actual or Estimated Revenue

Fundamental Highlights

- BWP's year-over-year revenue growth of 5.0% is substantially below the Pipelines Subsector average of 49.5%.
- Of the 44 firms within the Pipelines Subsector, BOARDWALK PIPELINE PARTNERS, LP is among the 37 companies that pay a dividend. The stock's dividend yield is currently 9.1%.
- BOARDWALK PIPELINE PARTNERS, LP's current ratio of 0.3 is substantially below the Pipelines Subsector average of 1.0.

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Fundamental Metrics

Profitability	BWP	Ind Avg	Debt	BWP	Ind Avg	Dividend	BWP	Ind Avg
Revenue Growth For year over year ending 03/08	5.0%	49.5%	**Current Ratio** For year over year ending --	0.3	1.0	**Div. Growth Rate** For year over year ending 03/08	14.5%	13.0%
Gross Margin For trailing 4 qtrs ending 03/08	65.4%	22.6%	**Debt-to-Capital** For trailing 4 qtrs ending 12/07	50.6%	50.6%	**Dividend Funding** For trailing 4 qtrs ending 03/08	62.7%	0.0%
Return on Equity For trailing 4 qtrs ending --	13.4%	10.9%	**Interest Funding** For trailing 4 qtrs ending 03/08	21.5%	0.0	**Dividend Coverage** For trailing 4 qtrs ending 12/07	1.5	1.6
Net Margin For trailing 4 qtrs ending 03/08	43.0%	6.7%	**Interest Coverage** For trailing 4 qtrs ending 03/08	5.7	3.3	**Current Div. Yield** For trailing 4 qtrs ending 01/09	9.4%	0.0%

The time period stated applies to the company-level data only. The Sector Average is a simple average of the most recent data from companies whose businesses most closely match each other.

Risk Highlights

- On days when the market is up, BWP tends to underperform the S&P 500 index by 54%. On days when the market is down, the shares generally decrease by 45% less than the S&P 500 index.
- Over the past 90 days, BWP shares have been more volatile than the overall market, as the stock's daily price fluctuations have exceeded that of 41% of S&P 500 index firms.
- In the short term, BWP has shown high correlation (>=40%) with the S&P 500 index. The stock has, however, shown low correlation (>=-10% and <20%) with the market in the long term.

Risk Metrics

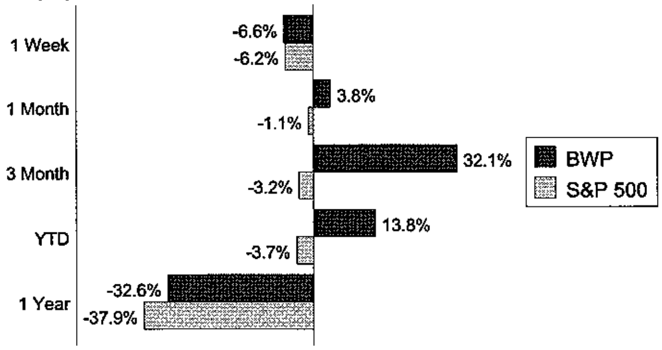
Standard Deviation		**Beta vs. S&P**	0.69	**Correlation vs. S&P**	
Last 90 Days	4.88	Positive Days Only	0.78	Last 90 Days	60%
Last 60 Months	7.47	Negative Days Only	0.79	Last 60 Months	6%
Intra-Day Swing		**Beta vs. Sector**	0.67	**Correlation vs. Sector**	
Last 90 Days Avg	6.7%	Positive Days Only	0.91	Last 90 Days	75%
Last 90 Days Largest	23.0%	Negative Days Only	0.55	Last 60 Months	0%

Price Analysis: Risk and Reward

	Last 90 Days					Last 60 Months		Last 10 Years		
Ticker	Best Daily Return	Worst Daily Return	# Days Up	# Days Down	Largest Intra-Day Swing	Best Monthly Return	Worst Monthly Return	Average January Return	Average February Return	Average March Return
BWP	24.1%	-9.9%	31	30	23.0%	16.5%	-23.5%	4.6%	-5.7%	3.8%
S&P 500	11.6%	-9.0%	30	32	10.4%	5.4%	-16.9%	-0.6%	-1.7%	0.6%

Price Performance

Daily closing pricing data is used to calculate the price performance of a stock over five periods. The performance of the S&P 500 is also displayed as a means of comparison.



	BWP	S&P 500
Close Price (01/12/09)	$20.23	870.26
52-Week High	$31.83	1440.24
52-Week Low	$14.00	741.02

- On 01/12/09, BWP closed at $20.23, 36.4% below its 52-week high and 44.5% above its 52-week low.
- BWP shares are currently trading 1.1% above their 50-day moving average of $20.01, and 10.2% below their 200-day moving average of $22.52.
- The S&P 500 is currently -39.0% below its 52-week high and 15.7% above its 52-week low.

Relative Strength Indicator (scale 1-100, 100 being best)	
Last 1 Month	55
Last 3 Months	50
Last 6 Months	48

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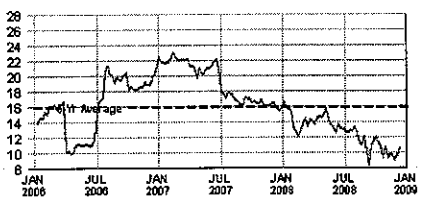
Valuation Multiples

	Trailing P/E	Forward P/E	Forward PEG
BWP	10.5	12.9	1.5
S&P 500	12.2	14.5	1.4
Company Relative to Its 5-Yr Average	35% Discount	24% Discount	41% Discount
Company Relative to S&P 500	14% Discount	11% Discount	7% Premium

Trailing PE

Trailing P/E is calculated using the most recent closing price (updated weekly) divided by the sum of the four most recently reported quarterly earnings.

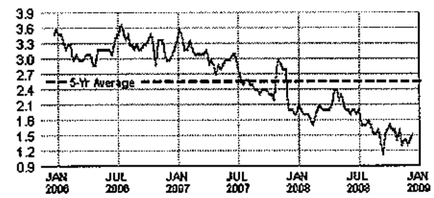


Forward PE

Forward P/E is calculated using the most recent closing price (updated weekly) divided by the sum of the four upcoming quarterly consensus estimates.

Forward PEG

Forward PEG is calculated by dividing the Forward P/E by the five-year, long term forecasted growth rate.



Insider Purchases and Sells

(Most recent transactions within the past 90 days)

Name	Role	Tran Date	Tran Type	Shares
Boardwalk, Pipelines...	Benef Owner	10/30/08-10/30/08	Purchase	$21,184,600

Seasonal $ Sells - Quarterly & Yearly

Time-series data for each quarter over the past three years allows you to easily analyze the longer-term trend in open-market insider selling.

	Q1	Q2	Q3	Q4	Full Year
2009	$0	–	–	–	$0
2008	$0	$0	$0	$0	$0
2007	$0	$0	$0	$0	$0
2006	$0	$0	$0	$0	$0

Seasonal $ Buys - Quarterly & Yearly

Time-series data for each quarter over the past three years allows you to easily analyze the longer-term trend in open-market insider buying.

	Q1	Q2	Q3	Q4	Full Year
2009	$0	–	–	–	$0
2008	$0	$0.55M	$0	$0	$0.55M
2007	$0	$0	$0	$0.08M	$77,210
2006	$0	$0	$0	$0	$0

Institutional Holders

(Updated weekly as of 01/10/09)

The top five institutional holders are presented based on the total number of shared held.

Institution	Inst. Type	# Shares Held	Reported Date
Loews Corporation (Investme...	Inv Mgmt	74.4M	11/13/08
Fidelity Management & Research	Inv Mgmt	8.12M	09/30/08
Neuberger Berman, LLC	Inv Mgmt	4.50M	09/30/08
Tortoise Capital Advisors, LLC	Inv Mgmt	1.87M	09/30/08
Lehman Brothers Inc.	Brokerag	1.51M	06/30/08

Top Executive Holders

(Updated monthly as of 11/16/08)

The top five insider holders are presented based on the total number of direct holdings. Indirect holdings are excluded. *Please see last page for role code legend.

Insider Name	* Role	# Direct Shares	$ Value	Reported Date
Rebell, Arthur L	D	6,000	$0.13M	11/05/07

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Distribution of Investment Ratings

As of 01/09/2009, Gradient Analytics covered 4584 companies, with 20.6% rated Buy, 60.2% rated Hold, and 19.2% rated Sell. Gradient Analytics does not engage in investment banking services.

Disclaimer

All information in this report is assumed to be accurate to the best of our ability. Past performance is not a guarantee of future results. The information contained in this report is not to be construed as advice and should not be confused as any sort of advice. Thomson Reuters, its employees, officers or affiliates, in some instances, have long or short positions or holdings in the securities or other related investments of companies mentioned herein. Investors should consider this report as only a single factor in making their investment decision.

Role Legend

AF	Affiliate	CT	CTO	R	Retired
B	Benef Owner	D	Director	SH	Shareholder
CB	Chairman	EVP	Exec VP	SVP	Sr VP
CEO	CEO	GC	Gen Counsel	T	Trustee
CFO	CFO	O	Officer	TR	Treasurer
CM	Committee Member	OH	Other	VC	Vice Chairman
CO	COO	P	President	VP	VP

Investment Methodology

Gradient Analytics, Inc (Gradient) is a private firm specializing in engineering stock rating systems and in providing independent specialized research to institutional clients. Gradient's exhaustive list of ratings include MSN/CNBC Money's StockScouter, and numerous institutional stock rating systems. Gradient also provides proprietary ratings of earnings quality, fundamental and valuation elements directly to institutional clients. Gradient was founded in 1996 by two former tenured professors, Dr. Carr Bettis and Dr. Donn Vickrey. Today the team consists of more than 30 financial engineers, research and business analysts and technology personnel.

The Gradient Opinion is an empirically-derived and historically backtested stock rating system with buy, sell and hold opinions. To develop a rating, the quantitative system analyzes a firm's earnings quality, balance sheet, and income statement, conducts technical and valuation analysis, and evaluates the transactions made by the company's management and directors (i.e. insiders).

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ENBRIDGE ENERGY PARTNERS LP (EEP-N)

OIL & GAS / OIL EQUIP. & SERVICES / PIPELINES

Gradient Opinion

The Gradient Opinion, provided by Gradient Analytics Inc, is an empirically-derived and historically back-tested stock rating system with buy, sell, and hold opinions. To develop a rating the quantitative system analyzes a firm's earnings quality, balance sheet, and income statement, conducts technical and valuation analysis and evaluates the transactions made by the company's management and directors (i.e. insiders).

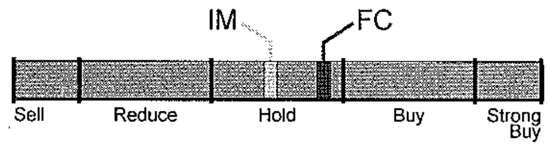
Gradient Analytics, Inc is a private independent research firm specializing in engineering institutional stock rating systems.

GRADIENT analytics

Analyst Recommendations

First Call Mean (FC): Hold (13 firms)

Independent Mean (IM): Hold (1 firms)

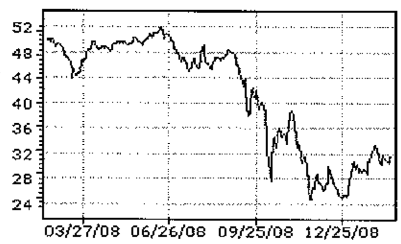


First Call Mean (FC) is the mean recommendation of all analysts covering the stock. Independent Mean (IM) is the mean recommendation of only independent analysts, which includes quantitative firms that are not included in the FC mean.

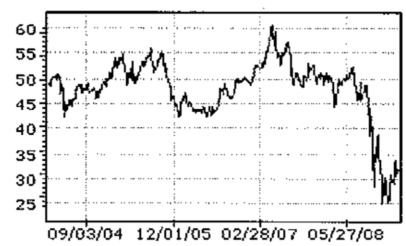
Key Information

Price (02/17/09)	$29.71
52-Week High	$53.45
52-Week Low	$22.33
Market Cap	$1.8B
Avg Daily Vol	445,421
Exchange	NYSE
Dividend Yield	13.3%
Annual Dividend	$3.96
P/E Cur Yr (12/09)	13.2
P/E Next Yr (12/10)	12.1
Forward PEG	2.9
LTG Forecast	5.0%
Exp Report Date	04/28/09
Annual Revenue	$10.1B
ROE	11.5%
Inst. Ownership	57.0%

1-Year Price Chart



5-Year Price Chart



Business Description

Enbridge Energy Partners LP. The Group's principal activity is to own and operate crude oil and liquid petroleum transportation assets, natural gas pipelines, marketing assets and related facilities in the United States. Currently, the Group operates under three segments: Liquids, Natural gas and Marketing. The Liquids segment consists of crude oil and liquid petroleum transportation and storage assets. It also includes the operations of Lakehead, North Dakota and Mid-Continent systems. Natural Gas segment consists of natural gas gathering and transmission pipelines, treating plants and processing plants. Marketing segment provides natural gas supply, transmission and sales services to the customers.

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Thomson Reuters Company in Context Report for EEP

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Peer Analysis

Ticker	Gradient Opinion	Price (01/13/09)	Market Cap	Dividend Yield	P/E Current Year	P/E Next Year	LTG Forecast	Annual Revenue	Net Margin	1-Mo Return	3-Mo Return	1-Yr Return
OKS	Buy	$46.02	$2.5B	9.2%	8.0	10.7	5.5%	--	--	-7.6%	-9.4%	-26.8%
OGE	Hold	$24.20	$2.4B	5.6%	10.1	10.2	6.0%	$4.3B	11.1%	-1.5%	-7.2%	-26.0%
MMP	Hold	$34.58	$2.3B	8.0%	11.9	11.6	6.1%	$1.3B	17.2%	8.3%	21.0%	-20.5%
BWP	Buy	$21.07	$2.3B	8.6%	11.7	11.4	8.4%	$785M	31.1%	1.7%	-3.1%	-28.4%
BPL	--	$40.16	$2.1B	8.6%	12.7	12.3	3.3%	$1.1B	6.9%	8.4%	14.7%	-18.9%
EEP	**Hold**	**$29.71**	**$1.8B**	**12.7%**	**13.2**	**12.1**	**5.0%**	**$10.1B**	**5.7%**	**2.3%**	**-0.6%**	**-40.2%**
SXL	Buy	$53.89	$1.6B	7.2%	11.4	11.2	4.2%	$10.1B	3.0%	9.9%	25.7%	1.0%
EPB	--	$17.51	$1.5B	7.0%	15.3	13.0	8.1%	$132M	58.8%	5.2%	5.0%	-24.5%
SEP	Hold	$20.50	$1.0B	6.8%	14.4	12.8	6.5%	$125M	76.5%	3.7%	0.0%	-18.4%
MGG	Hold	$15.93	$1.0B	8.7%	14.1	12.1	10.0%	$1.3B	6.2%	1.7%	4.7%	-37.1%
TCLP	Hold	$24.85	$880M	11.2%	9.5	9.8	5.0%	$30M	306.1%	0.0%	7.1%	-29.0%
Average	--	--	$1.8M	8.6%	12.0	11.6	6.2%	$2.9B	52.3%	2.9%	5.3%	-24.4%
Median	--	--	$1.8M	9.0%	11.9	11.6	6.0%	$1.2B	14.2%	2.3%	4.7%	-26.0%

Peer Group

OKS	ONEOK PARTNERS, L.P.
OGE	OGE ENERGY CORPORATION
MMP	MAGELLAN MIDSTREAM PARTNERS, L.P.
BWP	BOARDWALK PIPELINE PARTNERS, LP
BPL	BUCKEYE PARTNERS, L.P.
SXL	SUNOCO LOGISTICS PARTNERS LP
EPB	EL PASO PIPELINE PARTNERS, L.P.
SEP	SPECTRA ENERGY PARTNERS, LP
MGG	MAGELLAN MIDSTREAM HOLDINGS, L.P.
TCLP	TC PIPELINES, LP

Analyst Recommendations

First Call Mean (FC): Hold (13 firms)

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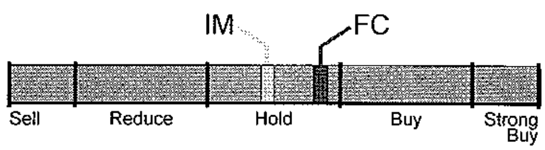


Distribution

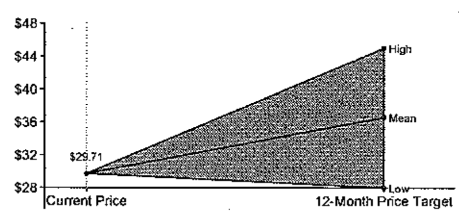
Analysts typically rate a stock based on a five-tier scale ranging from 'Strong Buy' to 'Sell'. The chart below displays the number of analysts in each tier.

Earnings Highlights

- On 02/06/09, the company announced quarterly earnings of $0.67 per share, a positive surprise of 9.3% above the consensus $0.61. Over the past 4 quarters, the company has reported 3 positive (>2%), 1 negative(<-2%), and 0 in-line (within 2%) surprises. The average surprise for this time period has been 5.7%.
- EEP's current quarter consensus estimate has decreased notably over the past 90 days from $0.73 to $0.55, a loss of -24.9%. This trails the average Pipelines Subsector move of -8.0% during the same time period.
- Over the past 90 days, the consensus price target for EEP has decreased notably from $43.70 to $36.60, a loss of -16.2%.

Price Target

The chart below indicates where analysts predict the stock price will be within the next 12 months, as compared to the curent price. The high, low, and mean price targets are presented.



12-Month Price Target	
Mean	$36.60
High	$45.00
Low	$28.00
Target vs. Current	23.2%
# of Analysts	9

Mean Estimate Trend

	Q 03-09	Q 06-09	Y 2009	Y 2010	Price Target
Current	$0.55	$0.56	$2.29	$2.59	$36.60
30 Days Ago	$0.59	$0.65	$2.80	$2.87	$39.70
90 Days Ago	$0.73	$0.76	$2.98	$3.12	$43.70
% Change - Last 90 Days	-24.9%	-26.2%	-23.2%	-16.8%	-16.2%

Next Expected Report Date: 04/28/09

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Earnings Per Share

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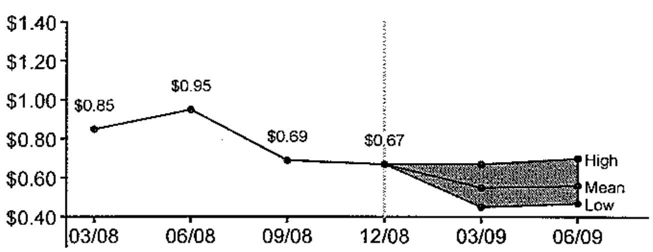
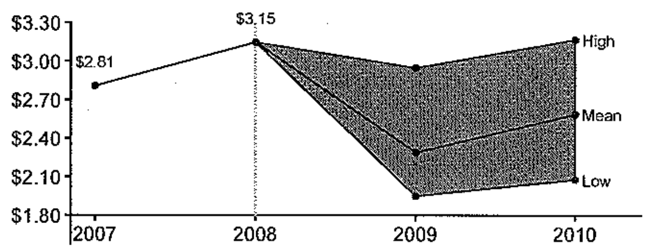
Quarterly



Estimates	03-09	06-09
FC Mean	$0.55	$0.56
High	$0.67	$0.70
Low	$0.45	$0.47
# of Analysts	11	9

NA = No Actual or Estimated EPS

Annual



Estimates	2009	2010
FC Mean	$2.29	$2.59
High	$2.95	$3.17
Low	$1.95	$2.08
# of Analysts	13	10

NA = No Actual or Estimated EPS

Earnings Surprise

Investors frequently compare a company's actual earnings to the mean expectation of professional analysts. The difference between the two is referred to as a "positive" or "negative" surprise. Academic research has shown that when a company reports a surprise, it is often followed by more of the same surprise type.

Surprise Summary - Last 3 Years

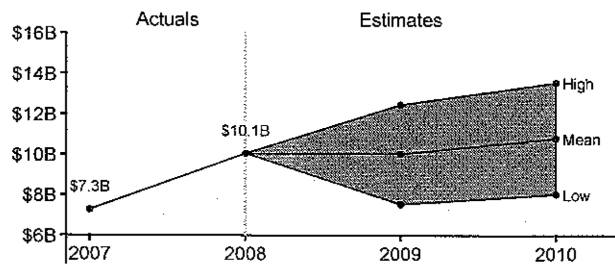
Surprise Type	#	%
Positive Quarters (> 2%)	8	66.7%
Negative Quarters (< -2%)	3	25.0%
In-Line Quarters (within 2%)	1	8.3%

Surprise Detail - Last 6 Periods

Surprise Type	Announce Date	Period End Date	Actual EPS	Mean EPS	Surprise (%)
POSITIVE	01/30/09	12/08	$0.670	$0.613	9.3%
NEGATIVE	10/30/08	09/08	$0.690	$0.875	-21.1%
POSITIVE	07/28/08	06/08	$0.950	$0.783	21.3%
POSITIVE	04/28/08	03/08	$0.850	$0.750	13.3%
IN-LINE	01/28/08	12/07	$0.740	$0.737	0.4%
POSITIVE	10/29/07	09/07	$0.810	$0.734	10.4%

Annual Revenue

A pattern of increasing sales in conjunction with a rising EPS may influence a buy recommendation, while flat or falling sales and faltering earnings may explain a sell recommendation. A rising EPS with flat or falling sales may result from increased cost efficiency and margins, rather than market expansion. This chart shows the revenue forecast trend of all analysts and the highest and lowest projections for the current and next fiscal year.



	2009	2010
Mean	$10.0B	$10.8B
High	$12.5B	$13.6B
Low	$7.6B	$8.0B
Forecasted Growth	-0.2%	7.4%
# of Analysts	8	8

NA = No Actual or Estimated Revenue

Fundamental Highlights

- EEP's current gross margin (trailing 4 quarters) of 17.6% is substantially above its five-year average of 10.5%.
- Of the 43 firms within the Pipelines Subsector, ENBRIDGE ENERGY PARTNERS LP is among the 37 companies that pay a dividend. The stock's dividend yield is currently 12.7%.
- The company's interest funding is at its five-year low.

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Fundamental Metrics

Profitability	EEP	Ind Avg
Revenue Growth For year over year ending 12/08	38.1%	43.5%
Gross Margin For trailing 4 qtrs ending 12/08	17.6%	22.6%
Return on Equity For trailing 4 qtrs ending 12/08	11.5%	10.9%
Net Margin For trailing 4 qtrs ending 12/08	5.7%	6.7%

Debt	EEP	Ind Avg
Current Ratio For year over year ending 12/08	1.0	1.0
Debt-to-Capital For trailing 4 qtrs ending 12/07	52.7%	50.6%
Interest Funding For trailing 4 qtrs ending 12/08	33.2%	0.0
Interest Coverage For trailing 4 qtrs ending 12/08	3.4	3.4

Dividend	EEP	Ind Avg
Div. Growth Rate For year over year ending 12/08	4.2%	12.2%
Dividend Funding For trailing 4 qtrs ending 12/08	46.9%	0.0%
Dividend Coverage For trailing 4 qtrs ending 12/07	1.8	1.6
Current Div. Yield For trailing 4 qtrs ending 02/09	13.3%	0.0%

The time period stated applies to the company-level data only. The Sector Average is a simple average of the most recent data from companies whose businesses most closely match each other.

Risk Highlights

- On days when the market is up, EEP tends to underperform the S&P 500 index by 53%. On days when the market is down, the shares generally decrease by 48% less than the S&P 500 index.
- Over the past 90 days, EEP shares have been more volatile than the overall market, as the stock's daily price fluctuations have exceeded that of -- of S&P 500 index firms.
- In both short-term and long-term periods, EEP has shown high correlation (>=40%) with the S&P 500 index. Thus, this stock would provide only low levels of diversification to a portfolio similar to the broader market.

Risk Metrics

Standard Deviation	
Last 90 Days	3.59
Last 60 Months	5.64
Intra-Day Swing	
Last 90 Days Avg	5.5%
Last 90 Days Largest	13.4%

Beta vs. S&P	0.72
Positive Days Only	0.77
Negative Days Only	0.84
Beta vs. Sector	0.71
Positive Days Only	0.97
Negative Days Only	0.64

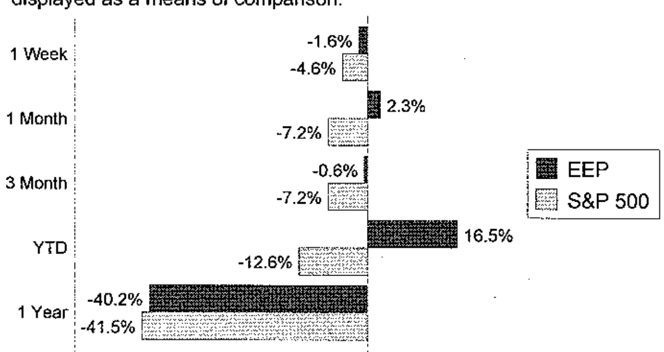
Correlation vs. S&P	
Last 90 Days	60%
Last 60 Months	40%
Correlation vs. Sector	
Last 90 Days	79%
Last 60 Months	53%

Price Analysis: Risk and Reward

	Last 90 Days					Last 60 Months		Last 10 Years		
Ticker	Best Daily Return	Worst Daily Return	# Days Up	# Days Down	Largest Intra-Day Swing	Best Monthly Return	Worst Monthly Return	Average February Return	Average March Return	Average April Return
EEP	11.0%	-12.1%	27	32	13.4%	10.6%	-18.1%	-1.4%	-0.4%	1.4%
S&P 500	6.5%	-8.9%	34	26	9.7%	5.4%	-16.9%	-1.7%	0.6%	1.8%

Price Performance

Daily closing pricing data is used to calculate the price performance of a stock over five periods. The performance of the S&P 500 is also displayed as a means of comparison.



	EEP	S&P 500
Close Price (02/17/09)	$29.71	789.17
52-Week High	$53.45	1440.24
52-Week Low	$22.33	741.02

- On 02/17/09, EEP closed at $29.71, 44.4% below its 52-week high and 33.0% above its 52-week low.
- EEP shares are currently trading 3.6% above their 50-day moving average of $28.69, and 23.7% below their 200-day moving average of $38.96.
- The S&P 500 is currently -44.7% below its 52-week high and 4.9% above its 52-week low.

Relative Strength Indicator (scale 1-100, 100 being best)	
Last 1 Month	54
Last 3 Months	48
Last 6 Months	46

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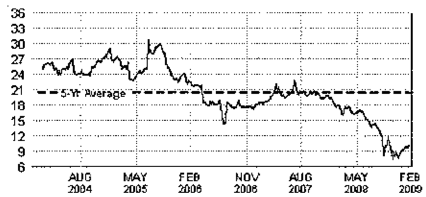
Valuation Multiples

	Trailing P/E	Forward P/E	Forward PEG
EEP	9.9	14.5	2.9
S&P 500	11.9	15.1	1.5
Company Relative to Its 5-Yr Average	52% Discount	27% Discount	26% Discount
Company Relative to S&P 500	17% Discount	4% Discount	92% Premium

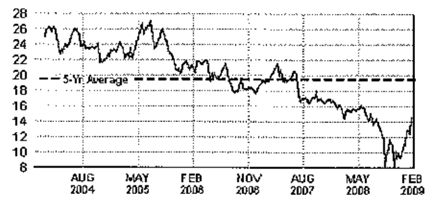
Trailing PE

Trailing P/E is calculated using the most recent closing price (updated weekly) divided by the sum of the four most recently reported quarterly earnings.



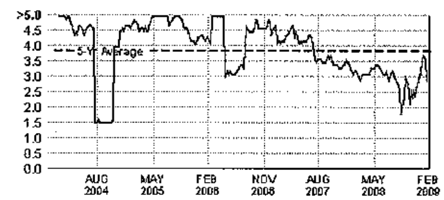
Forward PE

Forward P/E is calculated using the most recent closing price (updated weekly) divided by the sum of the four upcoming quarterly consensus estimates.



Forward PEG

Forward PEG is calculated by dividing the Forward P/E by the five-year, long term forecasted growth rate.



Insider Purchases and Sells

(Most recent transactions within the past 90 days)

Name	Role	Tran Date	Tran Type	Shares
Westbrook, Dan Allen	Director	12/22/08-12/22/08	Purchase	$3,500
Enbridge, Energy Co Inc	Director	12/04/08-12/04/08	Purchase	$16,250,000
Puckett, Kerry Connell	Officer	12/03/08-12/03/08	Purchase	$1,000
Westbrook, Dan Allen	Director	12/03/08-12/03/08	Purchase	$500
Loiacono, John A	Officer	12/03/08-12/03/08	Purchase	$1,000

Seasonal $ Sells - Quarterly & Yearly

Time-series data for each quarter over the past three years allows you to easily analyze the longer-term trend in open-market insider selling.

	Q1	Q2	Q3	Q4	Full Year
2009	$0	--	--	--	$0
2008	$0	$0	$0	$0	$0
2007	$0	$0	$0	$0	$0
2006	$0	$0	$0	$0	$0

Seasonal $ Buys - Quarterly & Yearly

Time-series data for each quarter over the past three years allows you to easily analyze the longer-term trend in open-market insider buying.

	Q1	Q2	Q3	Q4	Full Year
2009	$0	--	--	--	$0
2008	$0	$0	$0	$0.38M	$0.38M
2007	$0	$0	$0.10M	$0	$0.10M
2006	$0.10M	$0	$0.23M	$0.46M	$0.79M

Institutional Holders

(Updated weekly as of 02/14/09)

The top five institutional holders are presented based on the total number of shared held.

Institution	Inst. Type	# Shares Held	Reported Date
Enbridge Inc.	Strategic	16.3M	12/04/08
Kayne Anderson Capital Advi...	Inv Mgmt	1.84M	12/31/08
Macquarie Investment Manage...	Inv Mgmt	1.80M	12/31/08
Tortoise Capital Advisors, LLC	Inv Mgmt	1.69M	12/31/08
Fiduciary Asset Management, ...	Inv Mgmt	1.02M	09/30/08

Top Executive Holders

(Updated monthly as of 01/18/09)

The top five insider holders are presented based on the total number of direct holdings. Indirect holdings are excluded. *Please see last page for role code legend.

Insider Name	* Role	# Direct Shares	$ Value	Reported Date
Letwin, Stephen J J	O	15,000	$0.44M	11/24/08
Mcgill, Terrance L	P	2,000	$58,060	11/20/08
Loiacono, John A	O	1,000	$29,030	12/03/08
Puckett, Kerry Connell	O	1,000	$29,030	12/03/08

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Distribution of Investment Ratings

As of 02/13/2009, Gradient Analytics covered 4591 companies, with 19.8% rated Buy, 61.1% rated Hold, and 19.1% rated Sell. Gradient Analytics does not engage in investment banking services.

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Role Legend

AF	Affiliate	CT	CTO	R	Retired
B	Benef Owner	D	Director	SH	Shareholder
CB	Chairman	EVP	Exec VP	SVP	Sr VP
CEO	CEO	GC	Gen Counsel	T	Trustee
CFO	CFO	O	Officer	TR	Treasurer
CM	Committee Member	OH	Other	VC	Vice Chairman
CO	COO	P	President	VP	VP

Investment Methodology

Gradient Analytics, Inc (Gradient) is a private firm specializing in engineering stock rating systems and in providing independent specialized research to institutional clients. Gradient's exhaustive list of ratings include MSN/CNBC Money's StockScouter, and numerous institutional stock rating systems. Gradient also provides proprietary ratings of earnings quality, fundamental and valuation elements directly to institutional clients. Gradient was founded in 1996 by two former tenured professors, Dr. Carr Bettis and Dr. Donn Vickrey. Today the team consists of more than 30 financial engineers, research and business analysts and technology personnel.

The Gradient Opinion is an empirically-derived and historically backtested stock rating system with buy, sell and hold opinions. To develop a rating, the quantitative system analyzes a firm's earnings quality, balance sheet, and income statement, conducts technical and valuation analysis, and evaluates the transactions made by the company's management and directors (i.e. insiders).

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ENTERPRISE PRODUCTS PARTNERS LP (EPD-N)

OIL & GAS / OIL EQUIP. & SERVICES / PIPELINES

Gradient Opinion

Buy
Hold
Sell

The Gradient Opinion, provided by Gradient Analytics Inc, is an empirically-derived and historically back-tested stock rating system with buy, sell, and hold opinions. To develop a rating the quantitative system analyzes a firm's earnings quality, balance sheet, and income statement, conducts technical and valuation analysis and evaluates the transactions made by the company's management and directors (i.e. insiders).

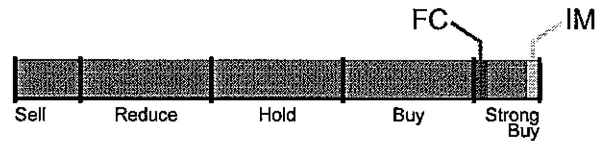
Gradient Analytics, Inc is a private independent research firm specializing in engineering institutional stock rating systems.

GRADIENT analytics

Analyst Recommendations

First Call Mean (FC): Strong Buy (14 firms)

Independent Mean (IM): Strong Buy (1 firms)

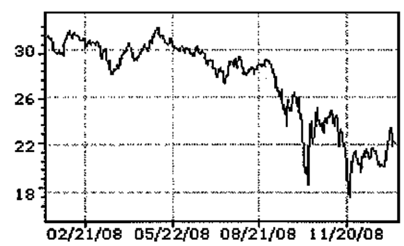


First Call Mean (FC) is the mean recommendation of all analysts covering the stock. Independent Mean (IM) is the mean recommendation of only independent analysts, which includes quantitative firms that are not included in the FC mean.

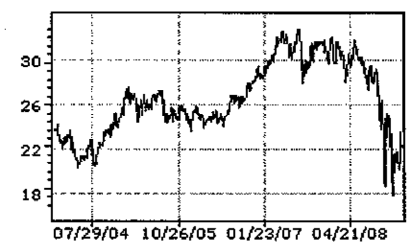
Key Information

Price (01/12/09)	$21.75
52-Week High	$32.64
52-Week Low	$16.00
Market Cap	$9.7B
Avg Daily Vol	2.0M
Exchange	NYSE
Dividend Yield	9.8%
Annual Dividend	$2.12
P/E Cur Yr (12/08)	11.9
P/E Next Yr (12/09)	11.0
Forward PEG	1.4
LTG Forecast	8.2%
Exp Report Date	01/28/09
Annual Revenue	$23.6B
ROE	12.5%
Inst. Ownership	64.3%

1-Year Price Chart



5-Year Price Chart



Business Description

Enterprise Products Partners LP. The Group's principal activity is to provide a range of midstream energy services. The operations of the Group are conducted through four segments. The offshore natural gas pipeline systems provide for the gathering and transmission of natural gas from natural gas production developments. The onshore natural gas pipeline systems provide for the gathering and transmission of natural gas from onshore developments or from offshore developments through connections with offshore pipelines. The NGL Pipelines & Services segment includes natural gas processing business and related NGL marketing activities, NGL pipelines and related storage facilities and NGL fractionation facilities. The Petrochemical Services business segment includes four propylene fractionation facilities, an isomerization complex, and an octane additive production facility. On 01-Jul-06, it acquired Encinal and Canales natural gas gathering systems and on 13-Jul-06, it acquired Cerrito Gathering Co Ltd

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Peer Analysis

Ticker	Gradient Opinion	Price (01/09/09)	Market Cap	Dividend Yield	P/E Current Year	P/E Next Year	LTG Forecast	Annual Revenue	Net Margin	1-Mo Return	3-Mo Return	1-Yr Return
EPD	**Buy**	**$21.75**	**$9.7B**	**9.6%**	**11.9**	**11.0**	**8.2%**	**$23.6B**	**2.7%**	**5.0%**	**18.3%**	**-31.7%**
WMB	Hold	$15.08	$9.2B	2.8%	7.4	9.7	15.0%	$12.7B	11.2%	2.4%	4.7%	-57.1%
KMP	Hold	$48.14	$8.6B	8.5%	20.2	20.0	6.3%	$11.9B	3.8%	-1.6%	10.7%	-13.5%
EP	Hold	$7.86	$5.9B	2.4%	6.5	7.4	6.3%	$4.9B	16.6%	7.2%	8.9%	-56.2%
ETP	Buy	$35.53	$5.6B	9.6%	10.1	8.8	6.3%	$7.1B	7.3%	2.3%	41.0%	-31.1%
PAA	Hold	$36.75	$4.7B	--	13.2	13.0	5.8%	$31.6B	2.0%	9.4%	28.5%	-27.1%
ETE	Buy	$17.47	$4.1B	10.4%	9.9	8.1	11.3%	$8.6B	4.8%	1.3%	27.7%	-47.4%
KMR	Hold	$42.22	$3.2B	--	18.0	19.3	6.0%	--	--	2.7%	7.5%	-18.1%
OKS	Buy	$50.99	$2.8B	8.4%	8.7	10.7	5.8%	--	--	9.0%	29.4%	-19.3%
NS	Buy	$44.88	$2.5B	9.2%	11.2	11.5	6.5%	$4.3B	7.8%	6.0%	45.3%	-18.1%
TPP	Hold	$23.14	$2.5B	12.2%	12.6	12.2	7.8%	$12.6B	0.9%	16.1%	17.5%	-39.4%
Average	--	--	$5.3M	8.1%	11.8	12.0	7.8%	$11.7B	6.3%	5.5%	21.8%	-32.6%
Median	--	--	$4.7M	9.0%	11.2	11.0	6.3%	$10.3B	4.8%	5.0%	18.3%	-31.1%

Peer Group

WMB	WILLIAMS COMPANIES, INC. (THE)
KMP	KINDER MORGAN ENERGY PARTNERS, L.P.
EP	EL PASO CORPORATION
ETP	ENERGY TRANSFER PARTNERS, LP
PAA	PLAINS ALL AMERICAN PIPELINE, L.P.
ETE	ENERGY TRANSFER EQUITY, L.P.
KMR	KINDER MORGAN MANAGEMENT LLC
OKS	ONEOK PARTNERS, L.P.
NS	NUSTAR ENERGY L P
TPP	TEPPCO PARTNERS, L.P.

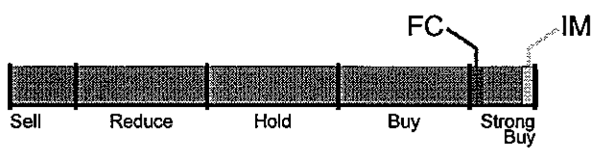
Earnings Highlights

- EPD's current quarter consensus estimate has decreased over the past 90 days from $0.53 to $0.44, a loss of -16.5%. Consensus estimates for the Pipelines Subsector have moved an average -8.0% during the same time period.
- Over the past 90 days, the consensus price target for EPD has decreased notably from $33.90 to $29.60, a loss of -12.7%.
- During the past four weeks, analysts covering EPD have made 1 upward and 1 downward EPS estimate revisions for the current quarter.

Analyst Recommendations

First Call Mean (FC): Strong Buy (14 firms)

Independent Mean (IM): Strong Buy (1 firms)

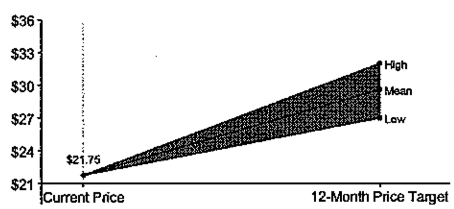


Distribution

Analysts typically rate a stock based on a five-tier scale ranging from 'Strong Buy' to 'Sell'. The chart below displays the number of analysts in each tier.

Price Target

The chart below indicates where analysts predict the stock price will be within the next 12 months, as compared to the curent price. The high, low, and mean price targets are presented.



12-Month Price Target	
Mean	$29.60
High	$32.00
Low	$27.00
Target vs. Current	36.1%
# of Analysts	11

Mean Estimate Trend

	Q 12-08	Q 03-09	Y 2008	Y 2009	Price Target
Current	$0.44	$0.46	$1.85	$2.01	$29.60
30 Days Ago	$0.44	$0.47	$1.85	$2.02	$30.20
90 Days Ago	$0.53	$0.50	$2.07	$2.20	$33.90
% Change - Last 90 Days	-16.5%	-11.5%	-10.6%	-9.7%	-12.7%

Next Expected Report Date: 01/28/09

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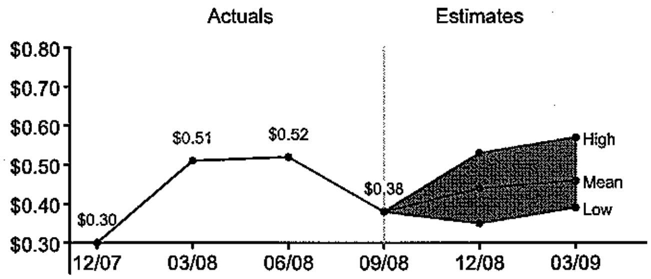
Earnings Per Share

Earnings per share (EPS) is calculated by dividing a company's earnings by the number of shares outstanding. Analysts tend to interpret a pattern of increasing earnings as a sign of strength and flat or falling earnings as a sign of weakness. The charts below provide a comparison between a company's actual and estimated EPS, including the high and low forecasts.

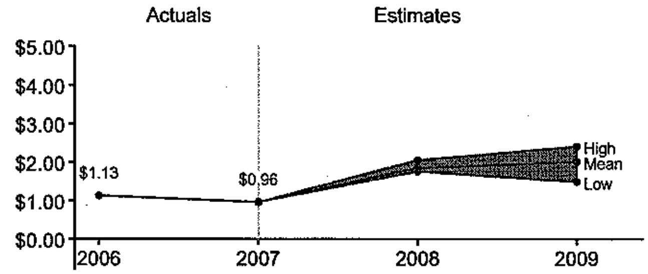
Quarterly



Estimates	12-08	03-09
FC Mean	$0.44	$0.46
High	$0.53	$0.57
Low	$0.35	$0.39
# of Analysts	14	8

NA = No Actual or Estimated EPS

Annual



Estimates	2008	2009
FC Mean	$1.85	$2.01
High	$2.05	$2.41
Low	$1.76	$1.49
# of Analysts	12	15

NA = No Actual or Estimated EPS

Earnings Surprise

Investors frequently compare a company's actual earnings to the mean expectation of professional analysts. The difference between the two is referred to as a "positive" or "negative" surprise. Academic research has shown that when a company reports a surprise, it is often followed by more of the same surprise type.

Surprise Summary - Last 3 Years

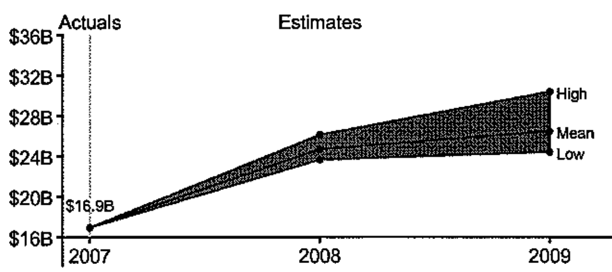
Surprise Type	#	%
Positive Quarters (> 2%)	7	58.3%
Negative Quarters (< -2%)	4	33.3%
In-Line Quarters (within 2%)	1	8.3%

Surprise Detail - Last 6 Periods

Surprise Type	Announce Date	Period End Date	Actual EPS	Mean EPS	Surprise (%)
NEGATIVE	10/23/08	09/08	$0.380	$0.491	-22.6%
POSITIVE	07/24/08	06/08	$0.520	$0.362	43.7%
POSITIVE	04/28/08	03/08	$0.510	$0.329	55.0%
NEGATIVE	01/28/08	12/07	$0.300	$0.318	-5.7%
NEGATIVE	10/25/07	09/07	$0.200	$0.271	-26.2%
IN-LINE	07/26/07	06/07	$0.260	$0.264	-1.5%

Annual Revenue

A pattern of increasing sales in conjunction with a rising EPS may influence a buy recommendation, while flat or falling sales and faltering earnings may explain a sell recommendation. A rising EPS with flat or falling sales may result from increased cost efficiency and margins, rather than market expansion. This chart shows the revenue forecast trend of all analysts and the highest and lowest projections for the current and next fiscal year.



	2008	2009
Mean	$24.7B	$26.5B
High	$26.1B	$30.4B
Low	$23.6B	$24.4B
Forecasted Growth	45.7%	56.3%
# of Analysts	7	7

NA = No Actual or Estimated Revenue

Fundamental Highlights

- ENTERPRISE PRODUCTS PARTNERS LP's gross margin (trailing 4 quarters) of 5.2% is substantially below the Pipelines Subsector average of 22.6%.
- Of the 44 firms within the Pipelines Subsector, ENTERPRISE PRODUCTS PARTNERS LP is among the 37 companies that pay a dividend. The stock's dividend yield is currently 9.6%.
- EPD's current interest funding of 3.0 is substantially above its five-year average of 2.4.

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Fundamental Metrics

Profitability	EPD	Ind Avg	Debt	EPD	Ind Avg	Dividend	EPD	Ind Avg
Revenue Growth For year over year ending 09/08	57.5%	49.5%	**Current Ratio** For year over year ending 09/08	0.9	1.0	**Div. Growth Rate** For year over year ending 09/08	6.8%	13.0%
Gross Margin For trailing 4 qtrs ending 09/08	5.2%	22.6%	**Debt-to-Capital** For trailing 4 qtrs ending 12/07	51.3%	50.6%	**Dividend Funding** For trailing 4 qtrs ending 09/08	89.8%	0.0%
Return on Equity For trailing 4 qtrs ending 09/08	12.5%	10.9%	**Interest Funding** For trailing 4 qtrs ending 09/08	39.3%	0.0	**Dividend Coverage** For trailing 4 qtrs ending 12/07	1.2	1.6
Net Margin For trailing 4 qtrs ending 09/08	2.7%	6.7%	**Interest Coverage** For trailing 4 qtrs ending 09/08	3.0	3.3	**Current Div. Yield** For trailing 4 qtrs ending 01/09	9.8%	0.0%

The time period stated applies to the company-level data only. The Sector Average is a simple average of the most recent data from companies whose businesses most closely match each other.

Risk Highlights

- On days when the market is up, EPD tends to perform in-line with the S&P 500 index. On days when the market is down, the shares generally decrease by 52% less than the S&P 500 index.
- Over the past 90 days, EPD shares have been more volatile than the overall market, as the stock's daily price fluctuations have exceeded that of 44% of S&P 500 index firms.
- In both short-term and long-term periods, EPD has shown high correlation (>=40%) with the S&P 500 index. Thus, this stock would provide only low levels of diversification to a portfolio similar to the broader market.

Risk Metrics

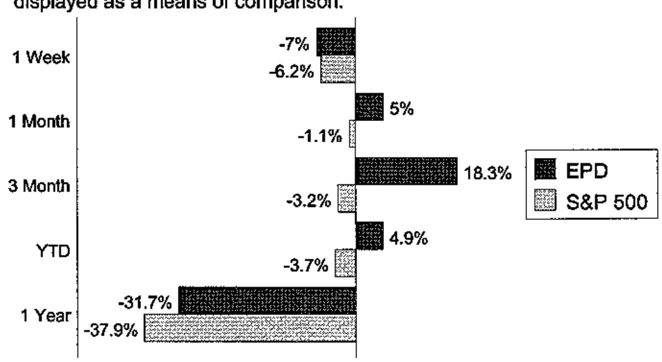
Standard Deviation		**Beta vs. S&P**	0.76	**Correlation vs. S&P**	
Last 90 Days	4.98	Positive Days Only	0.98	Last 90 Days	74%
Last 60 Months	4.62	Negative Days Only	0.88	Last 60 Months	52%
Intra-Day Swing		**Beta vs. Sector**	0.71	**Correlation vs. Sector**	
Last 90 Days Avg	6.4%	Positive Days Only	0.93	Last 90 Days	83%
Last 90 Days Largest	18.8%	Negative Days Only	0.66	Last 60 Months	49%

Price Analysis: Risk and Reward

	Last 90 Days					Last 60 Months		Last 10 Years		
Ticker	Best Daily Return	Worst Daily Return	# Days Up	# Days Down	Largest Intra-Day Swing	Best Monthly Return	Worst Monthly Return	Average January Return	Average February Return	Average March Return
EPD	24.5%	-11.6%	28	33	18.8%	8.5%	-12.5%	4.2%	-0.1%	0.1%
S&P 500	11.6%	-9.0%	30	32	10.4%	5.4%	-16.9%	-0.6%	-1.7%	0.6%

Price Performance

Daily closing pricing data is used to calculate the price performance of a stock over five periods. The performance of the S&P 500 is also displayed as a means of comparison.



	EPD	S&P 500
Close Price (01/12/09)	$21.75	870.26
52-Week High	$32.64	1440.24
52-Week Low	$16.00	741.02

- On 01/12/09, EPD closed at $21.75, 33.4% below its 52-week high and 35.9% above its 52-week low.
- EPD shares are currently trading 2.2% above their 50-day moving average of $21.28, and 17.9% below their 200-day moving average of $26.49.
- The S&P 500 is currently -39.0% below its 52-week high and 15.7% above its 52-week low.

Relative Strength Indicator (scale 1-100, 100 being best)	
Last 1 Month	52
Last 3 Months	47
Last 6 Months	47

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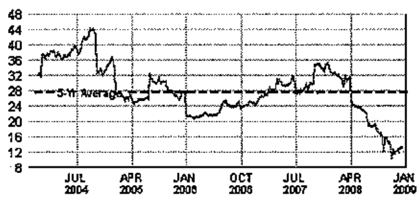
Valuation Multiples

	Trailing P/E	Forward P/E	Forward PEG
EPD	12.9	11.4	1.4
S&P 500	12.2	14.5	1.4
Company Relative to Its 5-Yr Average	54% Discount	49% Discount	47% Discount
Company Relative to S&P 500	6% Premium	21% Discount	3% Discount

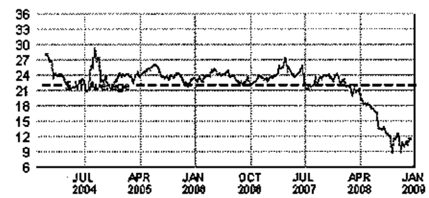
Trailing PE

Trailing P/E is calculated using the most recent closing price (updated weekly) divided by the sum of the four most recently reported quarterly earnings.



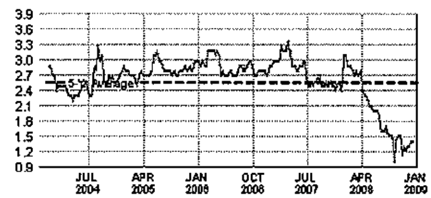
Forward PE

Forward P/E is calculated using the most recent closing price (updated weekly) divided by the sum of the four upcoming quarterly consensus estimates.



Forward PEG

Forward PEG is calculated by dividing the Forward P/E by the five-year, long term forecasted growth rate.



Insider Purchases and Sells

(Most recent transactions within the past 90 days)

Name	Role	Tran Date	Tran Type	Shares
Skoog, Christopher R	Officer	12/19/08-12/19/08	Purchase	$3,600
Teague, Angus James III	Officer	12/17/08-12/17/08	Purchase	$2,350
Lytal, James H	Officer	12/17/08-12/17/08	Purchase	$10,000
Rampacek, Charles M	Director	11/20/08-11/20/08	Purchase	$5,000

Seasonal $ Sells - Quarterly & Yearly

Time-series data for each quarter over the past three years allows you to easily analyze the longer-term trend in open-market insider selling.

	Q1	Q2	Q3	Q4	Full Year
2009	$0	--	--	--	$0
2008	$0	$0	$0	$0	$0
2007	$0	$0	$0	$0	$0
2006	$0	$0	$0	$0	$0

Seasonal $ Buys - Quarterly & Yearly

Time-series data for each quarter over the past three years allows you to easily analyze the longer-term trend in open-market insider buying.

	Q1	Q2	Q3	Q4	Full Year
2009	$0	--	--	--	$0
2008	$5.32M	$10.0M	$3.52M	$0.91M	$19.8M
2007	$7.04M	$0.03M	$14.3M	$0.10M	$21.5M
2006	$3.97M	$1.72M	$0	$1.19M	$6.89M

Institutional Holders

(Updated weekly as of 01/10/09)

The top five institutional holders are presented based on the total number of shared held.

Institution	Inst. Type	# Shares Held	Reported Date
Duncan (Dan L)	Strategic	148M	09/18/08
Shell U.s. Gas & Power, L.L.C.	Strategic	20.0M	01/22/07
Neuberger Berman, LLC	Inv Mgmt	9.87M	09/30/08
Kayne Anderson Capital Advi...	Inv Mgmt	8.88M	09/30/08
Goldman Sachs & Company, Inc.	Brokerag e	7.26M	09/30/08

Top Executive Holders

(Updated monthly as of 11/16/08)

The top five insider holders are presented based on the total number of direct holdings. Indirect holdings are excluded. *Please see last page for role code legend.

Insider Name	* Role	# Direct Shares	$ Value	Reported Date
Duncan, Dan L	CB	1.17M	$26.7M	09/19/08
Teague, Angus James III	O	0.21M	$4.92M	05/29/08
Creel, Michael A	CEO	0.16M	$3.68M	10/10/08
Bachmann, Richard H	O	0.16M	$3.56M	10/10/08
Phillips, Robert G	CEO	0.15M	$3.48M	05/30/07

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Distribution of Investment Ratings

As of 01/09/2009, Gradient Analytics covered 4584 companies, with 20.6% rated Buy, 60.2% rated Hold, and 19.2% rated Sell. Gradient Analytics does not engage in investment banking services.

Disclaimer

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Role Legend

AF	Affiliate	CT	CTO	R	Retired
B	Benef Owner	D	Director	SH	Shareholder
CB	Chairman	EVP	Exec VP	SVP	Sr VP
CEO	CEO	GC	Gen Counsel	T	Trustee
CFO	CFO	O	Officer	TR	Treasurer
CM	Committee Member	OH	Other	VC	Vice Chairman
CO	COO	P	President	VP	VP

Investment Methodology

Gradient Analytics, Inc (Gradient) is a private firm specializing in engineering stock rating systems and in providing independent specialized research to institutional clients. Gradient's exhaustive list of ratings include MSN/CNBC Money's StockScouter, and numerous institutional stock rating systems. Gradient also provides proprietary ratings of earnings quality, fundamental and valuation elements directly to institutional clients. Gradient was founded in 1996 by two former tenured professors, Dr. Carr Bettis and Dr. Donn Vickrey. Today the team consists of more than 30 financial engineers, research and business analysts and technology personnel.

The Gradient Opinion is an empirically-derived and historically backtested stock rating system with buy, sell and hold opinions. To develop a rating, the quantitative system analyzes a firm's earnings quality, balance sheet, and income statement, conducts technical and valuation analysis, and evaluates the transactions made by the company's management and directors (i.e. insiders).

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KINDER MORGAN ENERGY PARTNERS, L.P. (KMP-N)

OIL & GAS / OIL EQUIP. & SERVICES / PIPELINES

Gradient Opinion

The Gradient Opinion, provided by Gradient Analytics Inc, is an empirically-derived and historically back-tested stock rating system with buy, sell, and hold opinions. To develop a rating the quantitative system analyzes a firm's earnings quality, balance sheet, and income statement, conducts technical and valuation analysis and evaluates the transactions made by the company's management and directors (i.e. insiders).

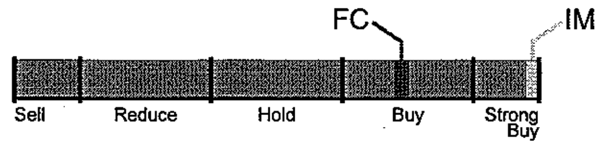
Gradient Analytics, Inc is a private independent research firm specializing in engineering institutional stock rating systems.

GRADIENT analytics

Analyst Recommendations

First Call Mean (FC): Buy (15 firms)

Independent Mean (IM): Strong Buy (1 firms)

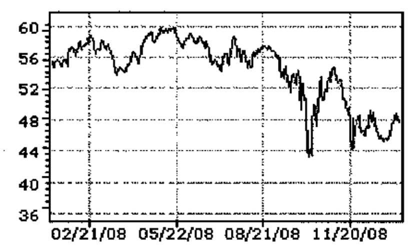


First Call Mean (FC) is the mean recommendation of all analysts covering the stock. Independent Mean (IM) is the mean recommendation of only independent analysts, which includes quantitative firms that are not included in the FC mean.

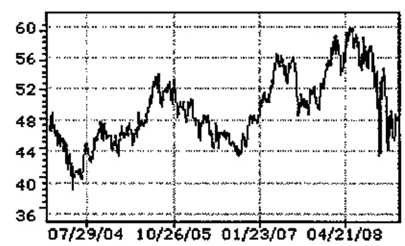
Key Information

Price (01/12/09)	$48.14
52-Week High	$60.89
52-Week Low	$35.59
Market Cap	$8.6B
Avg Daily Vol	1.1M
Exchange	NYSE
Dividend Yield	8.5%
Annual Dividend	$4.08
P/E Cur Yr (12/08)	20.2
P/E Next Yr (12/09)	20.0
Forward PEG	3.4
LTG Forecast	6.3%
Exp Report Date	01/26/09
Annual Revenue	$11.9B
ROE	12.5%
Inst. Ownership	31.8%

1-Year Price Chart



5-Year Price Chart



Business Description

Kinder Morgan Energy Partners, L.P.. The Group's principal activity is to own and manage diversified portfolio of midstream energy assets that provide fee-based services to customers. The operations are carried out through ltd partnerships. It operates in five business segments. Nat Gas Pipelines seg consist of a 15,000 miles natural gas pipelines & associated storage and supply lines. Products Pipelines seg transports refined petroleum products such as gasoline, diesel and jet fuel. Bulk Terminals seg operations involve bulk material handling services, provide terminal engineering and design services and in-plant services covering material handling, ship agency and miscellaneous marine services. CO2 Pipelines seg consist of the Kinder Organ Co2 Company L P, which produces and transports carbon dioxide for use in enhanced oil recovery operations. Trans mountain seg it transports crude oil and refined petroleum to its destinations. It operates in the United States and other countries.

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Peer Analysis

Ticker	Gradient Opinion	Price (01/09/09)	Market Cap	Dividend Yield	P/E Current Year	P/E Next Year	LTG Forecast	Annual Revenue	Net Margin	1-Mo Return	3-Mo Return	1-Yr Return
EPD	Buy	$21.75	$9.7B	9.6%	11.9	11.0	8.2%	$23.6B	2.7%	5.0%	18.3%	-31.7%
WMB	Hold	$15.08	$9.2B	2.8%	7.4	9.7	15.0%	$12.7B	11.2%	2.4%	4.7%	-57.1%
KMP	**Hold**	**$48.14**	**$8.6B**	**8.5%**	**20.2**	**20.0**	**6.3%**	**$11.9B**	**3.8%**	**-1.6%**	**10.7%**	**-13.5%**
EP	Hold	$7.86	$5.9B	2.4%	6.5	7.4	6.3%	$4.9B	16.6%	7.2%	8.9%	-56.2%
ETP	Buy	$35.53	$5.6B	9.6%	10.1	8.8	6.3%	$7.1B	7.3%	2.3%	41.0%	-31.1%
PAA	Hold	$36.75	$4.7B	--	13.2	13.0	5.8%	$31.6B	2.0%	9.4%	28.5%	-27.1%
ETE	Buy	$17.47	$4.1B	10.4%	9.9	8.1	11.3%	$8.6B	4.8%	1.3%	27.7%	-47.4%
KMR	Hold	$42.22	$3.2B	--	18.0	19.3	6.0%	--	--	2.7%	7.5%	-18.1%
OKS	Buy	$50.99	$2.8B	8.4%	8.7	10.7	5.8%	--	--	9.0%	29.4%	-19.3%
NS	Buy	$44.88	$2.5B	9.2%	11.2	11.5	6.5%	$4.3B	7.8%	6.0%	45.3%	-18.1%
TPP	Hold	$23.14	$2.5B	12.2%	12.6	12.2	7.8%	$12.6B	0.9%	16.1%	17.5%	-39.4%
Average	--	--	$5.3M	8.1%	11.8	12.0	7.8%	$11.7B	6.3%	5.5%	21.8%	-32.6%
Median	--	--	$4.7M	9.0%	11.2	11.0	6.3%	$10.3B	4.8%	5.0%	18.3%	-31.1%

Peer Group

EPD	ENTERPRISE PRODUCTS PARTNERS LP
WMB	WILLIAMS COMPANIES, INC. (THE)
EP	EL PASO CORPORATION
ETP	ENERGY TRANSFER PARTNERS, LP
PAA	PLAINS ALL AMERICAN PIPELINE, L.P.
ETE	ENERGY TRANSFER EQUITY, L.P.
KMR	KINDER MORGAN MANAGEMENT LLC
OKS	ONEOK PARTNERS, L.P.
NS	NUSTAR ENERGY L P
TPP	TEPPCO PARTNERS, L.P.

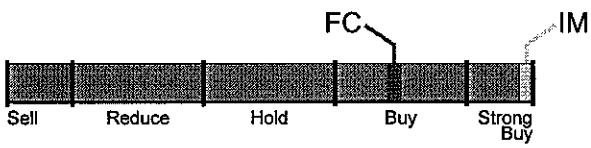
Earnings Highlights

- KMP's current quarter consensus estimate has decreased over the past 90 days from $0.59 to $0.54, a loss of -8.2%. Consensus estimates for the Pipelines Subsector have moved an average -8.0% during the same time period.
- During the past four weeks, analysts covering KMP have made 1 upward and 1 downward EPS estimate revisions for the current quarter.
- There have been 1 upward and 1 downward broker recommendation changes for KINDER MORGAN ENERGY PARTNERS L P over the past 120 days.

Analyst Recommendations

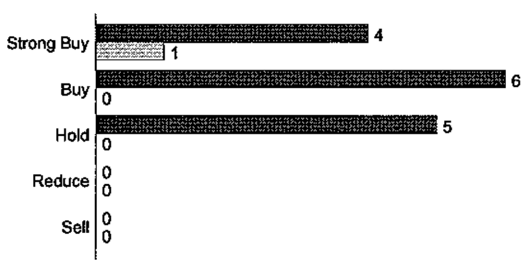
First Call Mean (FC): Buy (15 firms)

Independent Mean (IM): Strong Buy (1 firms)



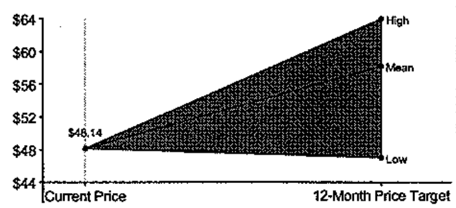
Distribution

Analysts typically rate a stock based on a five-tier scale ranging from 'Strong Buy' to 'Sell'. The chart below displays the number of analysts in each tier.



Price Target

The chart below indicates where analysts predict the stock price will be within the next 12 months, as compared to the curent price. The high, low, and mean price targets are presented.



12-Month Price Target	
Mean	$58.20
High	$64.00
Low	$47.00
Target vs. Current	20.9%
# of Analysts	11

Mean Estimate Trend

	Q 12-08	Q 03-09	Y 2008	Y 2009	Price Target
Current	$0.54	$0.53	$2.37	$2.38	$58.20
30 Days Ago	$0.55	$0.53	$2.39	$2.42	$58.30
90 Days Ago	$0.59	$0.61	$2.46	$2.65	$62.80
% Change - Last 90 Days	-8.2%	-13.4%	-3.7%	-10.0%	-7.3%

Next Expected Report Date: 01/26/09

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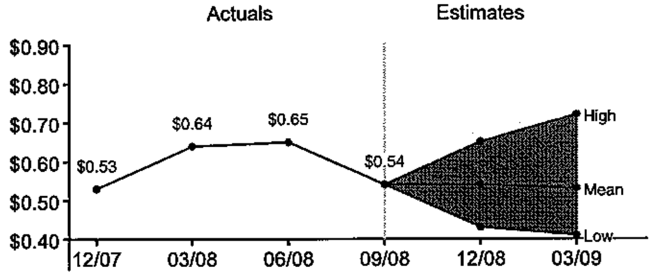
Earnings Per Share

Earnings per share (EPS) is calculated by dividing a company's earnings by the number of shares outstanding. Analysts tend to interpret a pattern of increasing earnings as a sign of strength and flat or falling earnings as a sign of weakness. The charts below provide a comparison between a company's actual and estimated EPS, including the high and low forecasts.

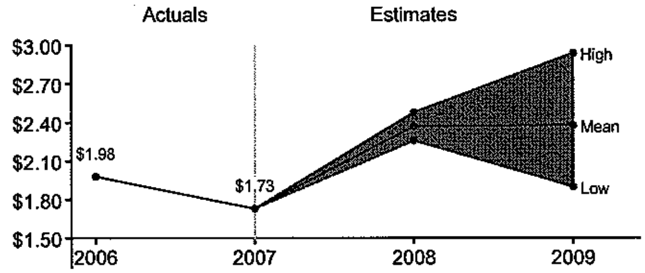
Quarterly



Estimates	12-08	03-09
FC Mean	$0.54	$0.53
High	$0.65	$0.72
Low	$0.43	$0.41
# of Analysts	13	9

NA = No Actual or Estimated EPS

Annual



Estimates	2008	2009
FC Mean	$2.37	$2.38
High	$2.48	$2.94
Low	$2.26	$1.90
# of Analysts	9	14

NA = No Actual or Estimated EPS

Earnings Surprise

Investors frequently compare a company's actual earnings to the mean expectation of professional analysts. The difference between the two is referred to as a "positive" or "negative" surprise. Academic research has shown that when a company reports a surprise, it is often followed by more of the same surprise type.

Surprise Summary - Last 3 Years

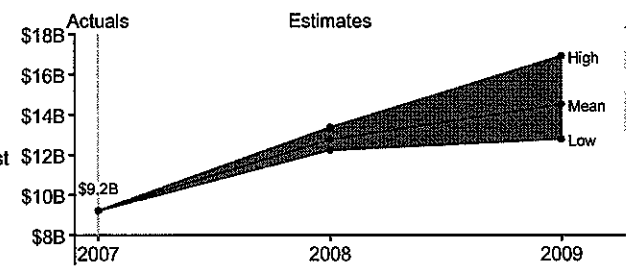
Surprise Type	#	%
Positive Quarters (> 2%)	6	50.0%
Negative Quarters (< -2%)	4	33.3%
In-Line Quarters (within 2%)	2	16.7%

Surprise Detail - Last 6 Periods

Surprise Type	Announce Date	Period End Date	Actual EPS	Mean EPS	Surprise (%)
NEGATIVE	10/15/08	09/08	$0.540	$0.592	-8.8%
POSITIVE	07/16/08	06/08	$0.650	$0.547	18.8%
POSITIVE	04/16/08	03/08	$0.640	$0.514	24.5%
POSITIVE	01/16/08	12/07	$0.530	$0.455	16.5%
IN-LINE	10/17/07	09/07	$0.430	$0.425	1.2%
POSITIVE	07/18/07	06/07	$0.430	$0.388	10.8%

Annual Revenue

A pattern of increasing sales in conjunction with a rising EPS may influence a buy recommendation, while flat or falling sales and faltering earnings may explain a sell recommendation. A rising EPS with flat or falling sales may result from increased cost efficiency and margins, rather than market expansion. This chart shows the revenue forecast trend of all analysts and the highest and lowest projections for the current and next fiscal year.



	2008	2009
Mean	$12.7B	$14.5B
High	$13.4B	$16.9B
Low	$12.2B	$12.8B
Forecasted Growth	38.2%	57.3%
# of Analysts	8	9

NA = No Actual or Estimated Revenue

Fundamental Highlights

- KINDER MORGAN ENERGY PARTNERS, L.P.'s net margin (trailing 4 quarters) of 3.8% is substantially below the Pipelines Subsector average of 6.7%.
- Of the 44 firms within the Pipelines Subsector, KINDER MORGAN ENERGY PARTNERS, L.P. is among the 37 companies that pay a dividend. The stock's dividend yield is currently 8.5%.
- KINDER MORGAN ENERGY PARTNERS, L.P.'s current ratio of 0.5 is substantially below the Pipelines Subsector average of 1.0.

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Fundamental Metrics

Profitability	KMP	Ind Avg	Debt	KMP	Ind Avg	Dividend	KMP	Ind Avg
Revenue Growth For year over year ending 09/08	34.3%	49.5%	**Current Ratio** For year over year ending 09/08	0.5	1.0	**Div. Growth Rate** For year over year ending 09/08	13.0%	13.0%
Gross Margin For trailing 4 qtrs ending 09/08	16.5%	22.6%	**Debt-to-Capital** For trailing 4 qtrs ending 12/07	59.5%	50.6%	**Dividend Funding** For trailing 4 qtrs ending 03/08	34.1%	0.0%
Return on Equity For trailing 4 qtrs ending 09/08	12.5%	10.9%	**Interest Funding** For trailing 4 qtrs ending 03/08	25.1%	0.0	**Dividend Coverage** For trailing 4 qtrs ending 12/07	2.4	1.6
Net Margin For trailing 4 qtrs ending 09/08	3.8%	6.7%	**Interest Coverage** For trailing 4 qtrs ending 09/08	4.2	3.3	**Current Div. Yield** For trailing 4 qtrs ending 01/09	8.5%	0.0%

The time period stated applies to the company-level data only. The Sector Average is a simple average of the most recent data from companies whose businesses most closely match each other.

Risk Highlights

- On days when the market is up, KMP tends to underperform the S&P 500 index by 39%. On days when the market is down, the shares generally decrease by 35% less than the S&P 500 index.
- Over the past 90 days, KMP shares have been more volatile than the overall market, as the stock's daily price fluctuations have exceeded that of -- of S&P 500 index firms.
- In the short term, KMP has shown high correlation (>=40%) with the S&P 500 index. The stock has, however, shown average correlation (>=20% and <40%) with the market in the long term.

Risk Metrics

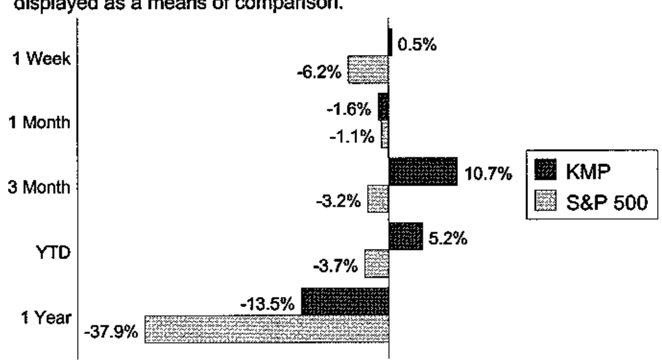
Standard Deviation		**Beta vs. S&P**	0.54	**Correlation vs. S&P**	
Last 90 Days	3.34	Positive Days Only	0.58	Last 90 Days	72%
Last 60 Months	4.37	Negative Days Only	0.66	Last 60 Months	22%
Intra-Day Swing		**Beta vs. Sector**	0.49	**Correlation vs. Sector**	
Last 90 Days Avg	4.4%	Positive Days Only	0.60	Last 90 Days	81%
Last 90 Days Largest	11.1%	Negative Days Only	0.52	Last 60 Months	28%

Price Analysis: Risk and Reward

	Last 90 Days					Last 60 Months		Last 10 Years		
Ticker	Best Daily Return	Worst Daily Return	# Days Up	# Days Down	Largest Intra-Day Swing	Best Monthly Return	Worst Monthly Return	Average January Return	Average February Return	Average March Return
KMP	14.9%	-8.2%	29	32	11.1%	11.9%	-9.4%	2.1%	-3.2%	0.8%
S&P 500	11.6%	-9.0%	30	32	10.4%	5.4%	-16.9%	-0.6%	-1.7%	0.6%

Price Performance

Daily closing pricing data is used to calculate the price performance of a stock over five periods. The performance of the S&P 500 is also displayed as a means of comparison.



	KMP	S&P 500
Close Price (01/12/09)	$48.14	870.26
52-Week High	$60.89	1440.24
52-Week Low	$35.59	741.02

- On 01/12/09, KMP closed at $48.14, 20.9% below its 52-week high and 35.3% above its 52-week low.
- KMP shares are currently trading 0.5% above their 50-day moving average of $47.91, and 10.9% below their 200-day moving average of $54.04.
- The S&P 500 is currently -39.0% below its 52-week high and 15.7% above its 52-week low.

Relative Strength Indicator (scale 1-100, 100 being best)	
Last 1 Month	50
Last 3 Months	47
Last 6 Months	47

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Thomson Reuters Company in Context Report for KMP

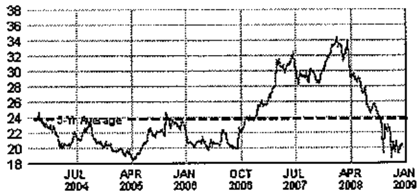
- Updated January 13, 2009

Valuation Multiples

	Trailing P/E	Forward P/E	Forward PEG
KMP	20.3	21.1	3.4
S&P 500	12.2	14.5	1.4
Company Relative to Its 5-Yr Average	16% Discount	7% Discount	14% Premium
Company Relative to S&P 500	67% Premium	46% Premium	>100% Premium

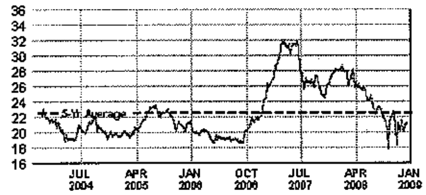
Trailing PE

Trailing P/E is calculated using the most recent closing price (updated weekly) divided by the sum of the four most recently reported quarterly earnings.



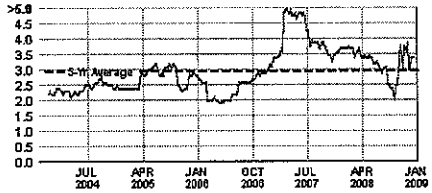
Forward PE

Forward P/E is calculated using the most recent closing price (updated weekly) divided by the sum of the four upcoming quarterly consensus estimates.



Forward PEG

Forward PEG is calculated by dividing the Forward P/E by the five-year, long term forecasted growth rate.



Insider Purchases and Sells

(Most recent transactions within the past 90 days)

Name	Role	Tran Date	Tran Type	Shares
Hultquist, Gary L	Director	10/20/08-10/20/08	Sale	$2,500

Seasonal $ Sells - Quarterly & Yearly

Time-series data for each quarter over the past three years allows you to easily analyze the longer-term trend in open-market insider selling.

	Q1	Q2	Q3	Q4	Full Year
2009	$0	--	--	--	$0
2008	$0	$0.69M	$0	$0.13M	$0.83M
2007	$0	$0	$0.55M	$0.10M	$0.65M
2006	$0	$0	$0	$0	$0

Seasonal $ Buys - Quarterly & Yearly

Time-series data for each quarter over the past three years allows you to easily analyze the longer-term trend in open-market insider buying.

	Q1	Q2	Q3	Q4	Full Year
2009	$0	--	--	--	$0
2008	$0	$0	$0	$0	$0
2007	$0	$0	$0	$0	$0
2006	$0	$0	$0	$0	$0

Institutional Holders

(Updated weekly as of 01/10/09)

The top five institutional holders are presented based on the total number of shared held.

Institution	Inst. Type	# Shares Held	Reported Date
KN Energy Inc	Strategic	14.4M	07/13/07
Pictet Asset Management Ltd.	Inv Mgmt	5.03M	09/30/08
Fayez Sarofim & Co.	Inv Mgmt	4.91M	09/30/08
Morgan Stanley Investment M...	Inv Mgmt	3.36M	09/30/08
Argyll Research, LLC	Inv Mgmt	2.03M	09/30/08

Top Executive Holders

(Updated monthly as of 11/16/08)

The top five insider holders are presented based on the total number of direct holdings. Indirect holdings are excluded. *Please see last page for role code legend.

Insider Name	* Role	# Direct Shares	$ Value	Reported Date
Waughtal, Perry M	D	46,918	$2.37M	01/16/08
Gaylord, Edward O	D	40,000	$2.02M	01/16/08
Hultquist, Gary L	D	7,500	$0.38M	10/20/08

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Distribution of Investment Ratings

As of 01/09/2009, Gradient Analytics covered 4584 companies, with 20.6% rated Buy, 60.2% rated Hold, and 19.2% rated Sell. Gradient Analytics does not engage in investment banking services.

Disclaimer

All information in this report is assumed to be accurate to the best of our ability. Past performance is not a guarantee of future results. The information contained in this report is not to be construed as advice and should not be confused as any sort of advice. Thomson Reuters, its employees, officers or affiliates, in some instances, have long or short positions or holdings in the securities or other related investments of companies mentioned herein. Investors should consider this report as only a single factor in making their investment decision.

Role Legend

AF	Affiliate	CT	CTO	R	Retired
B	Benef Owner	D	Director	SH	Shareholder
CB	Chairman	EVP	Exec VP	SVP	Sr VP
CEO	CEO	GC	Gen Counsel	T	Trustee
CFO	CFO	O	Officer	TR	Treasurer
CM	Committee Member	OH	Other	VC	Vice Chairman
CO	COO	P	President	VP	VP

Investment Methodology

Gradient Analytics, Inc (Gradient) is a private firm specializing in engineering stock rating systems and in providing independent specialized research to institutional clients. Gradient's exhaustive list of ratings include MSN/CNBC Money's StockScouter, and numerous institutional stock rating systems. Gradient also provides proprietary ratings of earnings quality, fundamental and valuation elements directly to institutional clients. Gradient was founded in 1996 by two former tenured professors, Dr. Carr Bettis and Dr. Donn Vickrey. Today the team consists of more than 30 financial engineers, research and business analysts and technology personnel.

The Gradient Opinion is an empirically-derived and historically backtested stock rating system with buy, sell and hold opinions. To develop a rating, the quantitative system analyzes a firm's earnings quality, balance sheet, and income statement, conducts technical and valuation analysis, and evaluates the transactions made by the company's management and directors (i.e. insiders).

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Thomson Reuters Company in Context Report

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ONEOK PARTNERS, L.P. (OKS-N)

OIL & GAS / OIL EQUIP. & SERVICES / PIPELINES

Gradient Opinion

The Gradient Opinion, provided by Gradient Analytics Inc, is an empirically-derived and historically back-tested stock rating system with buy, sell, and hold opinions. To develop a rating the quantitative system analyzes a firm's earnings quality, balance sheet, and income statement, conducts technical and valuation analysis and evaluates the transactions made by the company's management and directors (i.e. insiders).

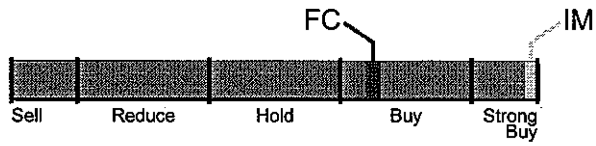
Gradient Analytics, Inc is a private independent research firm specializing in engineering institutional stock rating systems.

GRADIENT analytics

Analyst Recommendations

First Call Mean (FC): Buy (12 firms)

Independent Mean (IM): Strong Buy (1 firms)

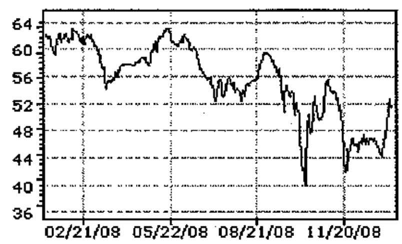


First Call Mean (FC) is the mean recommendation of all analysts covering the stock. Independent Mean (IM) is the mean recommendation of only independent analysts, which includes quantitative firms that are not included in the FC mean.

Key Information

Price (01/12/09)	$50.99
52-Week High	$64.87
52-Week Low	$35.61
Market Cap	$2.8B
Avg Daily Vol	161,200
Exchange	NYSE
Dividend Yield	8.5%
Annual Dividend	$4.32
P/E Cur Yr (12/08)	8.7
P/E Next Yr (12/09)	10.7
Forward PEG	2.0
LTG Forecast	5.8%
Exp Report Date	03/02/09
Annual Revenue	--
ROE	--
Inst. Ownership	24.1%

1-Year Price Chart



5-Year Price Chart

Business Description

Oneok Partners, L.P. Formerly known as Northern Border Partners, L.P.. The Group's principal activity is to gather, process, store and transport natural gas in the United States and owns the natural gas liquids (NGL) systems. The operations are conducted through four segments: Gathering and Processing: Gathers and processes raw natural gas. Gas Pipelines: Operates intrastate regulated interstate and intrastate natural gas transmission pipelines and natural gas storage facilities. Natural Gas Liquids: Gathers treats and fractionates raw NGLs and stores and markets purity NGL products. Gas Liquids Pipelines: Operates natural gas liquids gathering and distribution pipelines. ONEOK Inc, a diversified energy company is its general partner and owns 45.7 percent of the overall partnership interest.

Please refer to the last page for important disclaimer and certification information

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Thomson Reuters Company in Context Report for OKS

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Peer Analysis

Ticker	Gradient Opinion	Price (01/09/09)	Market Cap	Dividend Yield	P/E Current Year	P/E Next Year	LTG Forecast	Annual Revenue	Net Margin	1-Mo Return	3-Mo Return	1-Yr Return
EP	Hold	$7.86	$5.9B	2.4%	6.5	7.4	6.3%	$4.9B	16.6%	7.2%	8.9%	-56.2%
ETP	Buy	$35.53	$5.6B	9.6%	10.1	8.8	6.3%	$7.1B	7.3%	2.3%	41.0%	-31.1%
PAA	Hold	$36.75	$4.7B	--	13.2	13.0	5.8%	$31.6B	2.0%	9.4%	28.5%	-27.1%
ETE	Buy	$17.47	$4.1B	10.4%	9.9	8.1	11.3%	$8.6B	4.8%	1.3%	27.7%	-47.4%
KMR	Hold	$42.22	$3.2B	--	18.0	19.3	6.0%	--	--	2.7%	7.5%	-18.1%
OKS	**Buy**	**$50.99**	**$2.8B**	**8.4%**	**8.7**	**10.7**	**5.8%**	**--**	**--**	**9.0%**	**29.4%**	**-19.3%**
NS	Buy	$44.88	$2.5B	9.2%	11.2	11.5	6.5%	$4.3B	7.8%	6.0%	45.3%	-18.1%
TPP	Hold	$23.14	$2.5B	12.2%	12.6	12.2	7.8%	$12.6B	0.9%	16.1%	17.5%	-39.4%
EPE	Hold	$19.45	$2.4B	9.2%	12.6	12.5	7.5%	$37.9B	0.4%	3.8%	19.9%	-44.3%
OGE	Hold	$24.76	$2.3B	5.7%	9.8	9.8	6.0%	$4.3B	11.1%	0.5%	14.6%	-30.5%
MMP	Hold	$32.09	$2.2B	8.5%	10.8	10.6	6.1%	$1.3B	17.2%	4.1%	44.9%	-26.2%
Average	--	--	$3.5M	8.3%	11.2	11.3	6.9%	$11.3B	7.6%	5.7%	25.9%	-32.5%
Median	--	--	$2.8M	9.0%	10.8	10.7	6.3%	$6.0B	7.3%	4.1%	27.7%	-30.5%

Peer Group

EP	EL PASO CORPORATION
ETP	ENERGY TRANSFER PARTNERS, LP
PAA	PLAINS ALL AMERICAN PIPELINE, L.P.
ETE	ENERGY TRANSFER EQUITY, L.P.
KMR	KINDER MORGAN MANAGEMENT LLC
NS	NUSTAR ENERGY L P
TPP	TEPPCO PARTNERS, L.P.
EPE	ENTERPRISE GP HOLDINGS L.P.
OGE	OGE ENERGY CORPORATION
MMP	MAGELLAN MIDSTREAM PARTNERS, L.P.

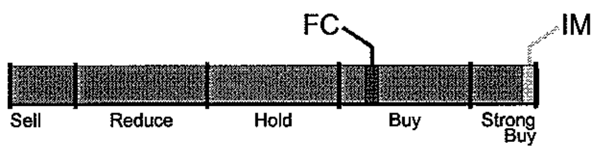
Earnings Highlights

- OKS's current quarter consensus estimate has decreased over the past 90 days from $1.18 to $1.12, a loss of -5.4%. Consensus estimates for the Pipelines Subsector have moved an average -8.0% during the same time period.
- During the past four weeks, analysts covering OKS have made 1 upward and 1 downward EPS estimate revisions for the current quarter.
- There have been 2 upward and 1 downward broker recommendation changes for ONEOK PARTNERS L P over the past 120 days.

Analyst Recommendations

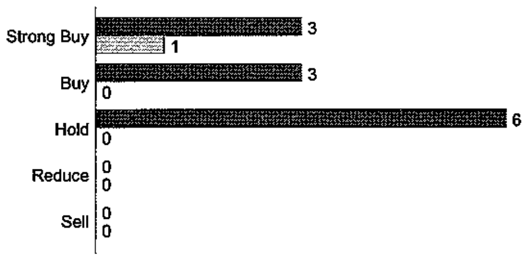
First Call Mean (FC): Buy (12 firms)

Independent Mean (IM): Strong Buy (1 firms)



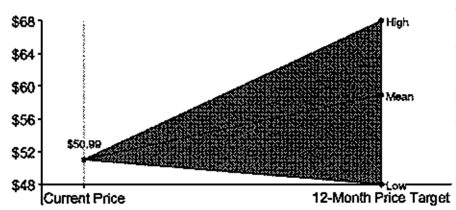
Distribution

Analysts typically rate a stock based on a five-tier scale ranging from 'Strong Buy' to 'Sell'. The chart below displays the number of analysts in each tier.



Price Target

The chart below indicates where analysts predict the stock price will be within the next 12 months, as compared to the curent price. The high, low, and mean price targets are presented.



12-Month Price Target	
Mean	$58.90
High	$68.00
Low	$48.00
Target vs. Current	15.5%
# of Analysts	9

Mean Estimate Trend

	Q 12-08	Q 03-09	Y 2008	Y 2009	Price Target
Current	$1.12	$1.08	$5.89	$4.77	$58.90
30 Days Ago	$1.14	$1.10	$5.91	$4.82	$59.10
90 Days Ago	$1.18	$1.18	$5.35	$5.05	$64.00
% Change - Last 90 Days	-5.4%	-8.7%	10.0%	-5.6%	-8.0%

Next Expected Report Date: 03/02/09

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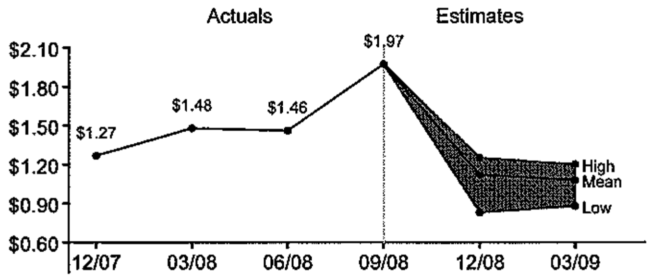
Thomson Reuters Company in Context Report for OKS

- Updated January 13, 2009

Earnings Per Share

Earnings per share (EPS) is calculated by dividing a company's earnings by the number of shares outstanding. Analysts tend to interpret a pattern of increasing earnings as a sign of strength and flat or falling earnings as a sign of weakness. The charts below provide a comparison between a company's actual and estimated EPS, including the high and low forecasts.

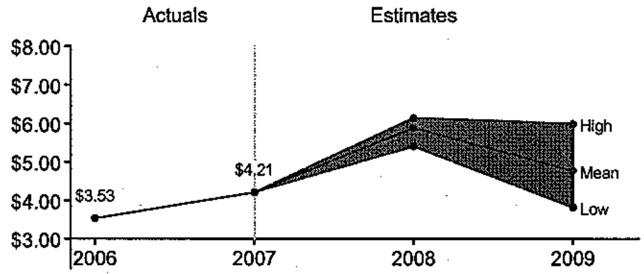
Quarterly



Estimates	12-08	03-09
FC Mean	$1.12	$1.08
High	$1.25	$1.20
Low	$0.83	$0.88
# of Analysts	11	7

NA = No Actual or Estimated EPS

Annual



Estimates	2008	2009
FC Mean	$5.89	$4.77
High	$6.15	$5.99
Low	$5.41	$3.82
# of Analysts	10	13

NA = No Actual or Estimated EPS

Earnings Surprise

Investors frequently compare a company's actual earnings to the mean expectation of professional analysts. The difference between the two is referred to as a "positive" or "negative" surprise. Academic research has shown that when a company reports a surprise, it is often followed by more of the same surprise type.

Surprise Summary - Last 3 Years

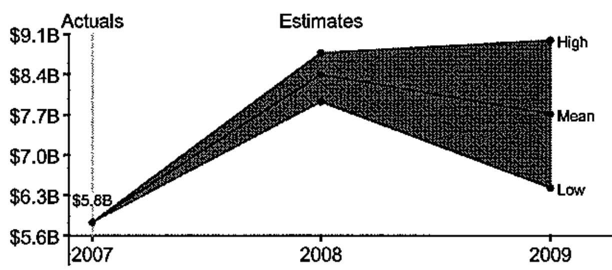
Surprise Type	#	%
Positive Quarters (> 2%)	10	83.3%
Negative Quarters (< -2%)	1	8.3%
In-Line Quarters (within 2%)	1	8.3%

Surprise Detail - Last 6 Periods

Surprise Type	Announce Date	Period End Date	Actual EPS	Mean EPS	Surprise (%)
POSITIVE	11/05/08	09/08	$1.970	$1.234	59.6%
POSITIVE	08/05/08	06/08	$1.460	$1.043	40.0%
POSITIVE	04/30/08	03/08	$1.480	$1.089	35.9%
POSITIVE	02/25/08	12/07	$1.270	$1.119	13.5%
POSITIVE	10/31/07	09/07	$0.980	$0.916	7.0%
POSITIVE	08/01/07	06/07	$0.970	$0.804	20.7%

Annual Revenue

A pattern of increasing sales in conjunction with a rising EPS may influence a buy recommendation, while flat or falling sales and faltering earnings may explain a sell recommendation. A rising EPS with flat or falling sales may result from increased cost efficiency and margins, rather than market expansion. This chart shows the revenue forecast trend of all analysts and the highest and lowest projections for the current and next fiscal year.



	2008	2009
Mean	$8.4B	$7.7B
High	$8.8B	$9.0B
Low	$7.9B	$6.4B
Forecasted Growth	44.0%	32.2%
# of Analysts	5	5

NA = No Actual or Estimated Revenue

Fundamental Highlights

- There is no Profitability information available due to the lack of current revenue growth, gross margin, net margin, and return on equity data.
- There is no Earnings Quality information available due to the lack of current days sales in inventory and days sales in receivables data.
- Of the 44 firms within the Pipelines Subsector, ONEOK PARTNERS, L.P. is among the 37 companies that pay a dividend. The stock's dividend yield is currently 8.4%.

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Thomson Reuters Company in Context Report for OKS

- Updated January 13, 2009

Fundamental Metrics

Profitability	OKS	Ind Avg	Debt	OKS	Ind Avg	Dividend	OKS	Ind Avg
Revenue Growth For year over year ending --	--	49.5%	**Current Ratio** For year over year ending --	--	1.0	**Div. Growth Rate** For year over year ending --	--	13.0%
Gross Margin For trailing 4 qtrs ending --	--	22.6%	**Debt-to-Capital** For trailing 4 qtrs ending --	--	50.6%	**Dividend Funding** For trailing 4 qtrs ending --	--	0.0%
Return on Equity For trailing 4 qtrs ending --	--	10.9%	**Interest Funding** For trailing 4 qtrs ending --	--	0.0	**Dividend Coverage** For trailing 4 qtrs ending --	--	1.6
Net Margin For trailing 4 qtrs ending --	--	6.7%	**Interest Coverage** For trailing 4 qtrs ending --	--	3.3	**Current Div. Yield** For trailing 4 qtrs ending 01/09	8.5%	0.0%

The time period stated applies to the company-level data only. The Sector Average is a simple average of the most recent data from companies whose businesses most closely match each other.

Risk Highlights

- On days when the market is up, OKS tends to underperform the S&P 500 index by 40%. On days when the market is down, the shares generally decrease by 39% less than the S&P 500 index.
- Over the past 90 days, OKS shares have been more volatile than the overall market, as the stock's daily price fluctuations have exceeded that of 17% of S&P 500 index firms.
- In the short term, OKS has shown high correlation (>=40%) with the S&P 500 index. The stock has, however, shown average correlation (>=20% and <40%) with the market in the long term.

Risk Metrics

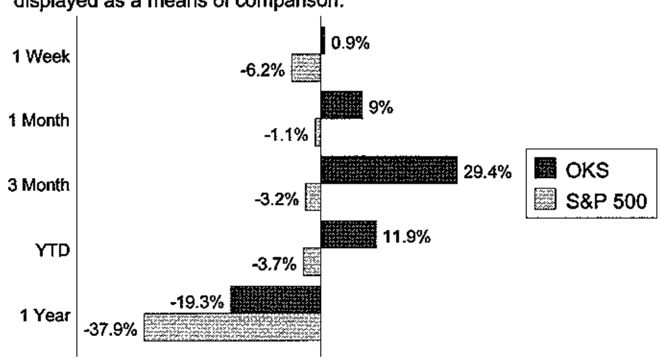
Standard Deviation		**Beta vs. S&P**	0.56	**Correlation vs. S&P**	
Last 90 Days	3.92	Positive Days Only	0.59	Last 90 Days	63%
Last 60 Months	5.06	Negative Days Only	0.71	Last 60 Months	34%
Intra-Day Swing		**Beta vs. Sector**	0.56	**Correlation vs. Sector**	
Last 90 Days Avg	5.4%	Positive Days Only	0.79	Last 90 Days	80%
Last 90 Days Largest	22.1%	Negative Days Only	0.51	Last 60 Months	29%

Price Analysis: Risk and Reward

	Last 90 Days					Last 60 Months		Last 10 Years		
Ticker	Best Daily Return	Worst Daily Return	# Days Up	# Days Down	Largest Intra-Day Swing	Best Monthly Return	Worst Monthly Return	Average January Return	Average February Return	Average March Return
OKS	18.9%	-8.0%	27	34	22.1%	12.4%	-15.5%	4.8%	0.9%	-0.6%
S&P 500	11.6%	-9.0%	30	32	10.4%	5.4%	-16.9%	-0.6%	-1.7%	0.6%

Price Performance

Daily closing pricing data is used to calculate the price performance of a stock over five periods. The performance of the S&P 500 is also displayed as a means of comparison.



	OKS	S&P 500
Close Price (01/12/09)	$50.99	870.26
52-Week High	$64.87	1440.24
52-Week Low	$35.61	741.02

- On 01/12/09, OKS closed at $50.99, 21.4% below its 52-week high and 43.2% above its 52-week low.
- OKS shares are currently trading 6.6% above their 50-day moving average of $47.82, and 5.9% below their 200-day moving average of $54.21.
- The S&P 500 is currently -39.0% below its 52-week high and 15.7% above its 52-week low.

Relative Strength Indicator (scale 1-100, 100 being best)	
Last 1 Month	58
Last 3 Months	50
Last 6 Months	48

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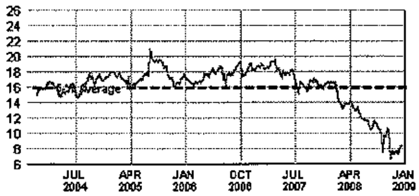
Valuation Multiples

	Trailing P/E	Forward P/E	Forward PEG
OKS	8.3	11.4	2.0
S&P 500	12.2	14.5	1.4
Company Relative to Its 5-Yr Average	49% Discount	31% Discount	39% Discount
Company Relative to S&P 500	31% Discount	21% Discount	39% Premium

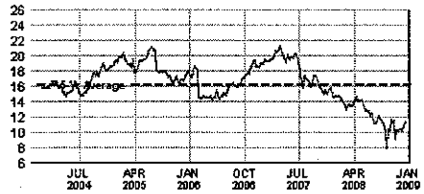
Trailing PE

Trailing P/E is calculated using the most recent closing price (updated weekly) divided by the sum of the four most recently reported quarterly earnings.



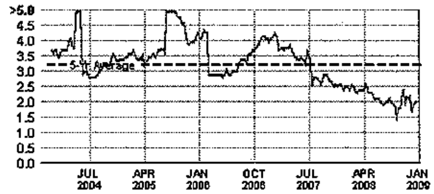
Forward PE

Forward P/E is calculated using the most recent closing price (updated weekly) divided by the sum of the four upcoming quarterly consensus estimates.



Forward PEG

Forward PEG is calculated by dividing the Forward P/E by the five-year, long term forecasted growth rate.



Insider Purchases and Sells

(Most recent transactions within the past 90 days)

Name	Role	Tran Date	Tran Type	Shares
Van, Lunsen Gil J	Affiliate	11/10/08-11/10/08	Purchase	$500

Seasonal $ Sells - Quarterly & Yearly

Time-series data for each quarter over the past three years allows you to easily analyze the longer-term trend in open-market insider selling.

	Q1	Q2	Q3	Q4	Full Year
2009	$0	--	--	--	$0
2008	$0	$0	$0	$0	$0
2007	$0	$0	$0	$0	$0
2006	$0	$0	$0	$0	$0

Seasonal $ Buys - Quarterly & Yearly

Time-series data for each quarter over the past three years allows you to easily analyze the longer-term trend in open-market insider buying.

	Q1	Q2	Q3	Q4	Full Year
2009	$0	--	--	--	$0
2008	$0.23M	$0	$0.44M	$0.03M	$0.69M
2007	$0.19M	$0.13M	$1.47M	$0	$1.79M
2006	$0	$0.24M	$2,236	$0	$0.24M

Institutional Holders

(Updated weekly as of 01/10/09)

The top five institutional holders are presented based on the total number of shared held.

Institution	Inst. Type	# Shares Held	Reported Date
Kayne Anderson Capital Advi...	Inv Mgmt	1.81M	09/30/08
Neuberger Berman, LLC	Inv Mgmt	1.32M	09/30/08
Goldman Sachs & Company, Inc.	Brokerag	0.95M	09/30/08
Tortoise Capital Advisors, LLC	Inv Mgmt	0.69M	09/30/08
Everett Harris & Co.	Inv Mgmt	0.60M	09/30/08

Top Executive Holders

(Updated monthly as of 11/16/08)

The top five insider holders are presented based on the total number of direct holdings. Indirect holdings are excluded. *Please see last page for role code legend.

Insider Name	* Role	# Direct Shares	$ Value	Reported Date
Kyle, David L	D	35,000	$1.81M	08/16/07
Gibson, John William	O	10,000	$0.52M	09/19/08
Petersen, Gary N	AF	8,392	$0.43M	08/20/08
Barker, John R	O	2,500	$0.13M	09/18/08
Dinan, Curtis L	O	2,000	$0.10M	09/22/08

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Distribution of Investment Ratings

As of 01/09/2009, Gradient Analytics covered 4584 companies, with 20.6% rated Buy, 60.2% rated Hold, and 19.2% rated Sell. Gradient Analytics does not engage in investment banking services.

Disclaimer

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Role Legend

AF	Affiliate	CT	CTO	R	Retired
B	Benef Owner	D	Director	SH	Shareholder
CB	Chairman	EVP	Exec VP	SVP	Sr VP
CEO	CEO	GC	Gen Counsel	T	Trustee
CFO	CFO	O	Officer	TR	Treasurer
CM	Committee Member	OH	Other	VC	Vice Chairman
CO	COO	P	President	VP	VP

Investment Methodology

Gradient Analytics, Inc (Gradient) is a private firm specializing in engineering stock rating systems and in providing independent specialized research to institutional clients. Gradient's exhaustive list of ratings include MSN/CNBC Money's StockScouter, and numerous institutional stock rating systems. Gradient also provides proprietary ratings of earnings quality, fundamental and valuation elements directly to institutional clients. Gradient was founded in 1996 by two former tenured professors, Dr. Carr Bettis and Dr. Donn Vickrey. Today the team consists of more than 30 financial engineers, research and business analysts and technology personnel.

The Gradient Opinion is an empirically-derived and historically backtested stock rating system with buy, sell and hold opinions. To develop a rating, the quantitative system analyzes a firm's earnings quality, balance sheet, and income statement, conducts technical and valuation analysis, and evaluates the transactions made by the company's management and directors (i.e. insiders).

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SOUTHERN UNION COMPANY (SUG-N)

UTILITIES / GAS, WATER & MUL UTIL / GAS DISTRIBUTION

Gradient Opinion

Buy
▶ **Hold**
Sell

The Gradient Opinion, provided by Gradient Analytics Inc, is an empirically-derived and historically back-tested stock rating system with buy, sell, and hold opinions. To develop a rating the quantitative system analyzes a firm's earnings quality, balance sheet, and income statement, conducts technical and valuation analysis and evaluates the transactions made by the company's management and directors (i.e. insiders).

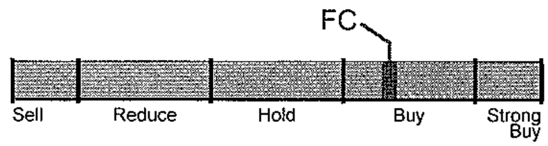
Gradient Analytics, Inc is a private independent research firm specializing in engineering institutional stock rating systems.

GRADIENT analytics

Analyst Recommendations

First Call Mean (FC): Buy (9 firms)

Independent Mean (IM): NA (0 firms)

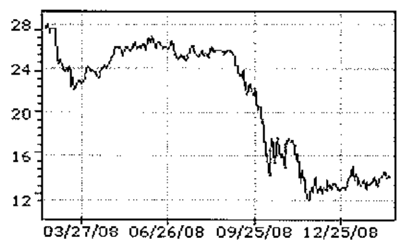


First Call Mean (FC) is the mean recommendation of all analysts covering the stock. Independent Mean (IM) is the mean recommendation of only independent analysts, which includes quantitative firms that are not included in the FC mean.

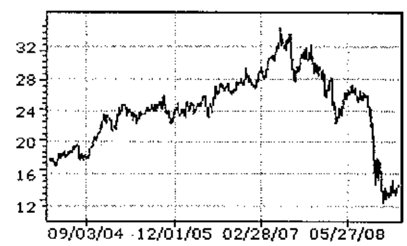
Key Information

Price (02/17/09)	$12.87
52-Week High	$28.62
52-Week Low	$10.60
Market Cap	$1.7B
Avg Daily Vol	1.5M
Exchange	NYSE
Dividend Yield	4.7%
Annual Dividend	$0.60
P/E Cur Yr (12/08)	7.7
P/E Next Yr (12/09)	8.1
Forward PEG	0.8
LTG Forecast	9.3%
Exp Report Date	03/16/09
Annual Revenue	$2.9B
ROE	10.2%
Inst. Ownership	86.7%

1-Year Price Chart



5-Year Price Chart



Business Description

Southern Union Company. The Group's principal activities are the transportation, storage and distribution of natural gas. The natural gas transmission units include Panhandle Eastern Pipe Line Company, Trunkline Gas Company, Sea Robin Pipeline Company, Trunkline LNG Company and Southwest Gas Storage. Through CCE Holdings, LLC, a joint venture with GE Commercial Finance Energy Financial Services, it owns interests in and operates the CrossCountry Energy pipelines. The Group's pipeline interests operate nearly 18,000 miles of interstate pipelines that transport natural gas from the San Juan and Permian Basins, the Rockies, the Gulf of Mexico, Mobile Bay, South Texas and the Panhandle regions of Texas and Oklahoma to markets in the Southeast, West, Midwest and Great Lakes region. The local distribution companies, Missouri Gas Energy, PG Energy and New England Gas Company serves nearly one million natural gas end-user customers in Missouri, Pennsylvania, Rhode Island and Massachusetts.

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Peer Analysis

Ticker	Gradient Opinion	Price (01/13/09)	Market Cap	Dividend Yield	P/E Current Year	P/E Next Year	LTG Forecast	Annual Revenue	Net Margin	1-Mo Return	3-Mo Return	1-Yr Return
ATO	Hold	$24.35	$2.4B	5.2%	12.1	11.7	5.0%	$7.3B	4.4%	-0.3%	2.2%	-9.9%
EGN	Sell	$28.89	$2.3B	1.6%	8.8	7.0	3.5%	$1.6B	17.4%	2.6%	-0.3%	-53.0%
PNY	Hold	$25.68	$2.0B	4.0%	16.1	15.1	7.1%	$1.9B	7.7%	-5.8%	-20.7%	2.3%
APU	Buy	$29.80	$1.8B	8.2%	10.8	11.2	8.3%	$2.8B	16.8%	-0.9%	4.7%	-8.2%
WGL	Hold	$32.64	$1.8B	4.2%	14.4	14.1	4.0%	$2.7B	6.6%	0.7%	-0.5%	0.6%
SUG	**Hold**	**$12.87**	**$1.7B**	**4.4%**	**7.7**	**8.1**	**9.3%**	**$2.9B**	**4.6%**	**-4.2%**	**-3.7%**	**-53.5%**
NJR	Buy	$37.96	$1.7B	3.2%	16.6	15.4	7.0%	$3.8B	9.5%	-0.8%	3.6%	16.4%
GAS	Hold	$31.76	$1.6B	5.4%	15.1	13.6	2.9%	$3.7B	0.3%	-5.5%	-21.0%	-16.4%
SPH	Hold	$37.58	$1.3B	8.3%	10.0	10.2	4.0%	$1.5B	22.2%	-0.4%	16.5%	-7.2%
NRGY	Hold	$24.11	$1.2B	10.4%	19.1	18.3	3.0%	$1.9B	2.7%	18.1%	37.4%	-17.4%
NWN	Hold	$42.74	$1.2B	3.6%	16.1	--	4.8%	$1.0B	1.7%	-1.2%	-11.2%	-7.0%
Average	--	--	$1.7M	5.2%	13.3	12.5	5.4%	$2.8B	8.5%	0.2%	0.6%	-13.9%
Median	--	--	$1.7M	4.0%	14.4	12.7	4.8%	$2.7B	6.6%	-0.8%	-0.3%	-8.2%

Peer Group

ATO	ATMOS ENERGY CORPORATION
EGN	ENERGEN CORPORATION
PNY	PIEDMONT NATURAL GAS COMPANY, INC.
APU	AMERIGAS PARTNERS, L.P.
WGL	WGL HOLDINGS INCORPORATED
NJR	NEW JERSEY RESOURCES CORPORATION
GAS	NICOR INC.
SPH	SUBURBAN PROPANE PARTNERS LP
NRGY	INERGY, L.P.
NWN	NORTHWEST NATURAL GAS COMPANY

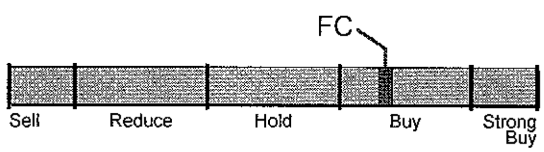
Earnings Highlights

- SUG's current quarter consensus estimate has decreased over the past 90 days from $0.46 to $0.44, a loss of -3.3%. Consensus estimates for the Gas Distribution Subsector have moved an average -1.0% during the same time period.
- Over the past 90 days, the consensus price target for SUG has decreased notably from $25.60 to $20.40, a loss of -20.3%.

Analyst Recommendations

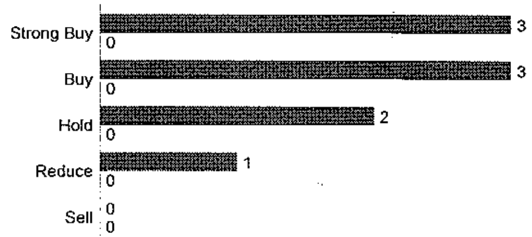
First Call Mean (FC): Buy (9 firms)

Independent Mean (IM): NA (0 firms)



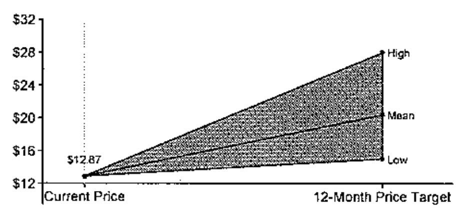
Distribution

Analysts typically rate a stock based on a five-tier scale ranging from 'Strong Buy' to 'Sell'. The chart below displays the number of analysts in each tier.



Price Target

The chart below indicates where analysts predict the stock price will be within the next 12 months, as compared to the curent price. The high, low, and mean price targets are presented.



12-Month Price Target	
Mean	$20.40
High	$28.00
Low	$15.00
Target vs. Current	58.5%
# of Analysts	7

Mean Estimate Trend

	Q 12-08	Q 03-09	Y 2008	Y 2009	Price Target
Current	$0.44	$0.59	$1.79	$1.70	$20.40
30 Days Ago	$0.45	$0.63	$1.80	$1.80	$21.40
90 Days Ago	$0.46	$0.63	$1.80	$1.92	$25.60
% Change - Last 90 Days	-3.3%	-6.4%	-0.4%	-11.2%	-20.3%

Next Expected Report Date: 03/16/09

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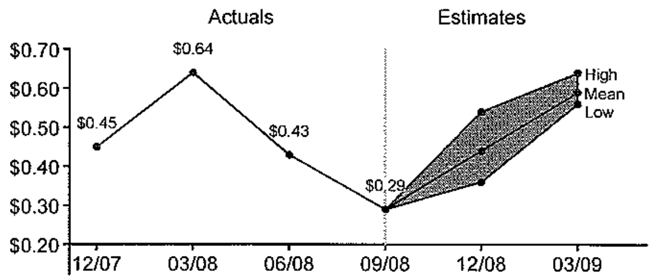
Earnings Per Share

Earnings per share (EPS) is calculated by dividing a company's earnings by the number of shares outstanding. Analysts tend to interpret a pattern of increasing earnings as a sign of strength and flat or falling earnings as a sign of weakness. The charts below provide a comparison between a company's actual and estimated EPS, including the high and low forecasts.

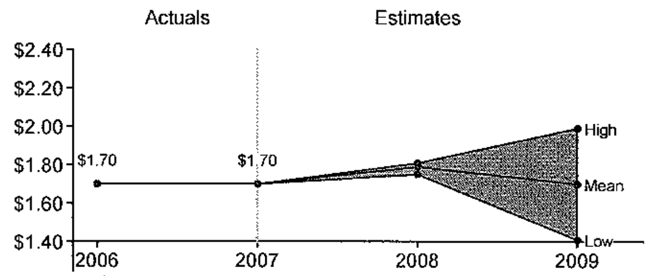
Quarterly



Estimates	12-08	03-09
FC Mean	$0.44	$0.59
High	$0.54	$0.64
Low	$0.36	$0.56
# of Analysts	9	3

NA = No Actual or Estimated EPS

Annual



Estimates	2008	2009
FC Mean	$1.79	$1.70
High	$1.81	$1.99
Low	$1.75	$1.41
# of Analysts	8	9

NA = No Actual or Estimated EPS

Earnings Surprise

Investors frequently compare a company's actual earnings to the mean expectation of professional analysts. The difference between the two is referred to as a "positive" or "negative" surprise. Academic research has shown that when a company reports a surprise, it is often followed by more of the same surprise type.

Surprise Summary - Last 3 Years

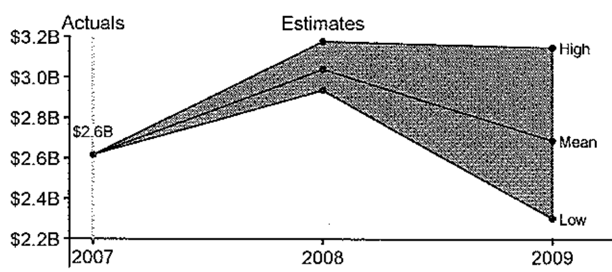
Surprise Type	#	%
Positive Quarters (> 2%)	6	50.0%
Negative Quarters (< -2%)	6	50.0%
In-Line Quarters (within 2%)	0	--

Surprise Detail - Last 6 Periods

Surprise Type	Announce Date	Period End Date	Actual EPS	Mean EPS	Surprise (%)
NEGATIVE	11/10/08	09/08	$0.290	$0.334	-13.2%
POSITIVE	08/07/08	06/08	$0.430	$0.396	8.6%
POSITIVE	05/08/08	03/08	$0.640	$0.605	5.8%
NEGATIVE	02/29/08	12/07	$0.450	$0.497	-9.5%
POSITIVE	11/09/07	09/07	$0.340	$0.320	6.3%
POSITIVE	08/09/07	06/07	$0.390	$0.305	27.9%

Annual Revenue

A pattern of increasing sales in conjunction with a rising EPS may influence a buy recommendation, while flat or falling sales and faltering earnings may explain a sell recommendation. A rising EPS with flat or falling sales may result from increased cost efficiency and margins, rather than market expansion. This chart shows the revenue forecast trend of all analysts and the highest and lowest projections for the current and next fiscal year.



	2008	2009
Mean	$3.0B	$2.7B
High	$3.2B	$3.1B
Low	$2.9B	$2.3B
Forecasted Growth	16.2%	2.7%
# of Analysts	5	5

NA = No Actual or Estimated Revenue

Fundamental Highlights

- SUG's current return on equity of 10.2% is substantially above its five-year average of 5.2%.
- Of the 30 firms within the Gas Distribution Subsector, SOUTHERN UNION COMPANY is among the 28 companies that pay a dividend. The stock's dividend yield is currently 4.4%.
- SOUTHERN UNION COMPANY's interest funding of 0.6% is substantially above the Gas Distribution Subsector average of 0.4%.

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Fundamental Metrics

Profitability	SUG	Ind Avg	Debt	SUG	Ind Avg	Dividend	SUG	Ind Avg
Revenue Growth For year over year ending 06/08	14.0%	15.3%	**Current Ratio** For year over year ending 06/08	0.8	1.0	**Div. Growth Rate** For year over year ending 06/08	37.5%	4.3%
Gross Margin For trailing 4 qtrs ending 06/08	30.7%	25.8%	**Debt-to-Capital** For trailing 4 qtrs ending 12/07	57.3%	48.4%	**Dividend Funding** For trailing 4 qtrs ending 06/08	19.3%	0.0%
Return on Equity For trailing 4 qtrs ending 06/08	10.2%	12.0%	**Interest Funding** For trailing 4 qtrs ending 06/08	57.9%	0.0	**Dividend Coverage** For trailing 4 qtrs ending 12/07	10.8	3.5
Net Margin For trailing 4 qtrs ending 06/08	4.6%	4.4%	**Interest Coverage** For trailing 4 qtrs ending 06/08	2.0	3.4	**Current Div. Yield** For trailing 4 qtrs ending 02/09	4.7%	0.0%

The time period stated applies to the company-level data only. The Sector Average is a simple average of the most recent data from companies whose businesses most closely match each other.

Risk Highlights

- On days when the market is up, SUG tends to outperform the S&P 500 index by 82%. However, on days when the market is down, the shares generally decrease by 77% more than the S&P 500 index.
- Over the past 90 days, SUG shares have been more volatile than the overall market, as the stock's daily price fluctuations have exceeded that of 46% of S&P 500 index firms.
- In both short-term and long-term periods, SUG has shown high correlation (>=40%) with the S&P 500 index. Thus, this stock would provide only low levels of diversification to a portfolio similar to the broader market.

Risk Metrics

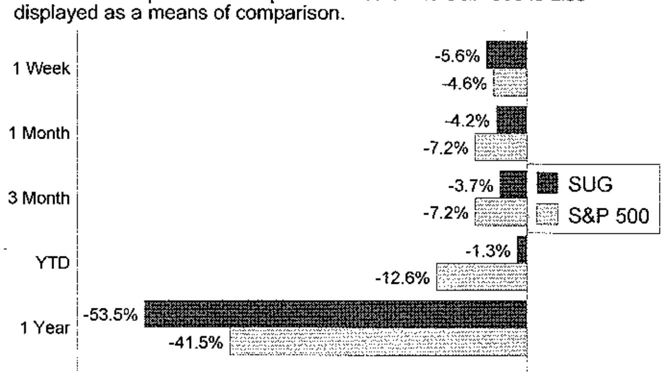
Standard Deviation		**Beta vs. S&P**	1.10	**Correlation vs. S&P**	
Last 90 Days	3.93	Positive Days Only	1.20	Last 90 Days	76%
Last 60 Months	6.70	Negative Days Only	1.25	Last 60 Months	75%
Intra-Day Swing		**Beta vs. Sector**	1.47	**Correlation vs. Sector**	
Last 90 Days Avg	5.9%	Positive Days Only	1.53	Last 90 Days	74%
Last 90 Days Largest	12.0%	Negative Days Only	1.45	Last 60 Months	65%

Price Analysis: Risk and Reward

	Last 90 Days					Last 60 Months		Last 10 Years		
Ticker	Best Daily Return	Worst Daily Return	# Days Up	# Days Down	Largest Intra-Day Swing	Best Monthly Return	Worst Monthly Return	Average February Return	Average March Return	Average April Return
SUG	10.5%	-10.8%	34	25	12.0%	14.3%	-20.8%	-2.5%	-0.3%	4.2%
S&P 500	6.5%	-8.9%	34	26	9.7%	5.4%	-16.9%	-1.7%	0.6%	1.8%

Price Performance

Daily closing pricing data is used to calculate the price performance of a stock over five periods. The performance of the S&P 500 is also displayed as a means of comparison.



	SUG	S&P 500
Close Price (02/17/09)	$12.87	789.17
52-Week High	$28.62	1440.24
52-Week Low	$10.60	741.02

- On 02/17/09, SUG closed at $12.87, 55.0% below its 52-week high and 21.4% above its 52-week low.
- SUG shares are currently trading 2.9% below their 50-day moving average of $13.26, and 35.0% below their 200-day moving average of $19.80.
- The S&P 500 is currently -44.7% below its 52-week high and 4.9% above its 52-week low.

Relative Strength Indicator (scale 1-100, 100 being best)	
Last 1 Month	51
Last 3 Months	45
Last 6 Months	45

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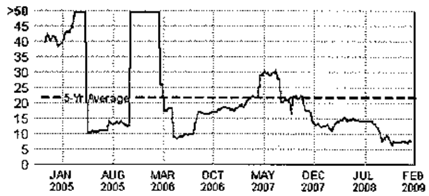
Valuation Multiples

	Trailing P/E	Forward P/E	Forward PEG
SUG	7.6	7.8	.8
S&P 500	11.9	15.1	1.5
Company Relative to Its 5-Yr Average	66% Discount	49% Discount	64% Discount
Company Relative to S&P 500	36% Discount	49% Discount	45% Discount

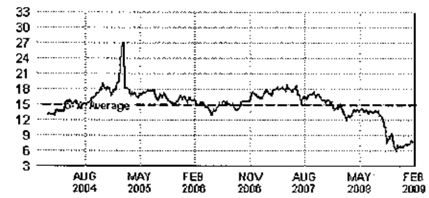
Trailing PE

Trailing P/E is calculated using the most recent closing price (updated weekly) divided by the sum of the four most recently reported quarterly earnings.



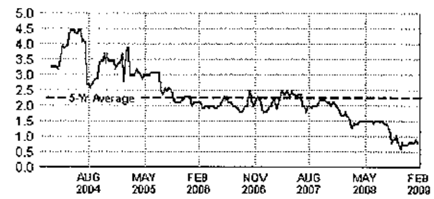
Forward PE

Forward P/E is calculated using the most recent closing price (updated weekly) divided by the sum of the four upcoming quarterly consensus estimates.



Forward PEG

Forward PEG is calculated by dividing the Forward P/E by the five-year, long term forecasted growth rate.



Insider Purchases and Sells

(Most recent transactions within the past 90 days)

Name	Role	Tran Date	Tran Type	Shares
Lindemann, George L	CEO	01/12/09-01/12/09	Purchase	$862
Rountree, George H III	Director	11/21/08-11/21/08	Purchase	$5,000

Seasonal $ Sells - Quarterly & Yearly

Time-series data for each quarter over the past three years allows you to easily analyze the longer-term trend in open-market insider selling.

	Q1	Q2	Q3	Q4	Full Year
2009	$0	--	--	--	$0
2008	$0	$0	$0	$0	$0
2007	$0	$0.20M	$0	$0	$0.20M
2006	$0.87M	$0.61M	$0.42M	$1.26M	$3.16M

Seasonal $ Buys - Quarterly & Yearly

Time-series data for each quarter over the past three years allows you to easily analyze the longer-term trend in open-market insider buying.

	Q1	Q2	Q3	Q4	Full Year
2009	$0.01M	--	--	--	$11,939
2008	$0	$3,846	$0.02M	$0.20M	$0.22M
2007	$0	$0	$0	$0	$0
2006	$0.21M	$0	$0	$0.61M	$0.82M

Institutional Holders

(Updated weekly as of 02/14/09)

The top five institutional holders are presented based on the total number of shared held.

Institution	Inst. Type	# Shares Held	Reported Date
Sandell Asset Management	Inv Mgmt	12.3M	12/05/08
Lindemann (George L)	Strategic	7.47M	12/12/08
Baron Capital Management, Inc.	Inv Mgmt	6.93M	12/31/08
Barclays Global Investors, ...	Inv Mgmt	5.93M	12/31/08
Blue Harbour Group, L.P.	Inv Mgmt	4.66M	09/30/08

Top Executive Holders

(Updated monthly as of 01/18/09)

The top five insider holders are presented based on the total number of direct holdings. Indirect holdings are excluded. *Please see last page for role code legend.

Insider Name	* Role	# Direct Shares	$ Value	Reported Date
Lindemann, George L	CEO	4.37M	$58.7M	01/14/09
Lindemann, Adam M	D	3.23M	$43.4M	05/13/08
Herschmann, Eric D	P	0.43M	$5.77M	12/17/08
Gitter, Kurt A	D	0.27M	$3.61M	12/09/08
Rountree, George H III	D	0.11M	$1.46M	11/25/08

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Thomson Reuters Company in Context Report for SUG

Distribution of Investment Ratings

As of 02/13/2009, Gradient Analytics covered 4591 companies, with 19.8% rated Buy, 61.1% rated Hold, and 19.1% rated Sell. Gradient Analytics does not engage in investment banking services.

Disclaimer

All information in this report is assumed to be accurate to the best of our ability. Past performance is not a guarantee of future results. The information contained in this report is not to be construed as advice and should not be confused as any sort of advice. Thomson Reuters, its employees, officers or affiliates, in some instances, have long or short positions or holdings in the securities or other related investments of companies mentioned herein. Investors should consider this report as only a single factor in making their investment decision.

Role Legend

AF	Affiliate	CT	CTO	R	Retired
B	Benef Owner	D	Director	SH	Shareholder
CB	Chairman	EVP	Exec VP	SVP	Sr VP
CEO	CEO	GC	Gen Counsel	T	Trustee
CFO	CFO	O	Officer	TR	Treasurer
CM	Committee Member	OH	Other	VC	Vice Chairman
CO	COO	P	President	VP	VP

Investment Methodology

Gradient Analytics, Inc (Gradient) is a private firm specializing in engineering stock rating systems and in providing independent specialized research to institutional clients. Gradient's exhaustive list of ratings include MSN/CNBC Money's StockScouter, and numerous institutional stock rating systems. Gradient also provides proprietary ratings of earnings quality, fundamental and valuation elements directly to institutional clients. Gradient was founded in 1996 by two former tenured professors, Dr. Carr Bettis and Dr. Donn Vickrey. Today the team consists of more than 30 financial engineers, research and business analysts and technology personnel.

The Gradient Opinion is an empirically-derived and historically backtested stock rating system with buy, sell and hold opinions. To develop a rating, the quantitative system analyzes a firm's earnings quality, balance sheet, and income statement, conducts technical and valuation analysis, and evaluates the transactions made by the company's management and directors (i.e. insiders).

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SPECTRA ENERGY CORP (SE-N)

UTILITIES / GAS, WATER & MUL UTIL / GAS DISTRIBUTION

Gradient Opinion

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Gradient Analytics, Inc is a private independent research firm specializing in engineering institutional stock rating systems.

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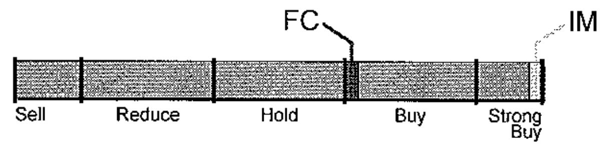
Analyst Recommendations

First Call Mean (FC): Buy (14 firms)

Independent Mean (IM): Strong Buy (1 firms)

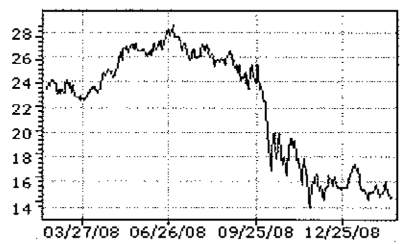


First Call Mean (FC) is the mean recommendation of all analysts covering the stock. Independent Mean (IM) is the mean recommendation of only independent analysts, which includes quantitative firms that are not included in the FC mean.

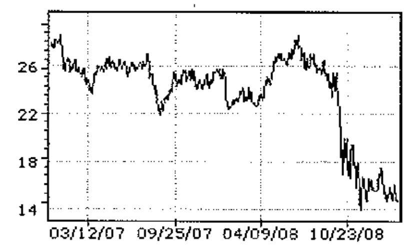
Key Information

Price (02/17/09)	$13.53
52-Week High	$29.18
52-Week Low	$13.36
Market Cap	$9.7B
Avg Daily Vol	5.2M
Exchange	NYSE
Dividend Yield	7.4%
Annual Dividend	$1.00
P/E Cur Yr (12/09)	12.8
P/E Next Yr (12/10)	10.0
Forward PEG	2.0
LTG Forecast	6.5%
Exp Report Date	05/11/09
Annual Revenue	$5.1B
ROE	18.2%
Inst. Ownership	62.4%

1-Year Price Chart



5-Year Price Chart



Business Description

Spectra Energy Corp. The Group's principal activity is to own and operate a large and diversified portfolio of complementary natural gas-related assets. It operates in three key areas of the natural gas industry: gathering and processing, transmission and storage and distribution. The Group provides transportation and storage of natural gas to customers in various regions of the Eastern and Southeastern United States, the Maritime Provinces and the Pacific Northwest in the United States and Canada, and in the province of Ontario, Canada. The natural gas related-assets include more than 18,000 miles of transmission pipeline and approximately 272 billion cubic feet of storage capacity. In addition, it also owns a 50% interest in DCP Midstream, LLC, a natural gas liquids producer and marketer.

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Peer Analysis

Ticker	Gradient Opinion	Price (01/13/09)	Market Cap	Dividend Yield	P/E Current Year	P/E Next Year	LTG Forecast	Annual Revenue	Net Margin	1-Mo Return	3-Mo Return	1-Yr Return
SE	**Hold**	**$13.53**	**$9.7B**	**7.0%**	**12.8**	**10.0**	**6.5%**	**$5.1B**	**13.6%**	**-8.5%**	**-15.7%**	**-41.5%**
STR	Hold	$32.11	$6.3B	1.4%	9.3	11.2	9.0%	$3.2B	20.1%	-4.9%	12.9%	-40.7%
EQT	Sell	$34.00	$5.1B	--	19.0	14.5	11.7%	--	--	3.0%	13.9%	-42.0%
NI	Hold	$9.49	$3.0B	9.1%	9.3	8.8	1.6%	$8.7B	1.4%	-11.4%	-19.2%	-47.5%
OKE	Hold	$26.37	$2.9B	5.7%	9.4	10.4	9.1%	$17.3B	1.4%	-7.7%	-1.6%	-43.9%
UGI	Buy	$25.25	$2.9B	3.0%	11.8	11.5	6.0%	$6.7B	6.5%	2.0%	8.6%	-4.2%
NFG	Sell	$32.08	$2.6B	3.9%	13.5	12.8	5.0%	$2.4B	-7.0%	10.2%	0.6%	-30.3%
ATG	Buy	$30.49	$2.6B	5.5%	11.5	10.8	4.3%	$2.8B	9.2%	-2.7%	5.0%	-16.2%
ATO	Hold	$24.35	$2.4B	5.2%	12.1	11.7	5.0%	$7.3B	4.4%	-0.3%	2.2%	-9.9%
EGN	Sell	$28.89	$2.3B	1.6%	8.8	7.0	3.5%	$1.6B	17.4%	2.6%	-0.3%	-53.0%
PNY	Hold	$25.68	$2.0B	4.0%	16.1	15.1	7.1%	$1.9B	7.7%	-5.8%	-20.7%	2.3%
Average	--	--	$3.8M	4.6%	12.1	11.3	6.3%	$5.7B	7.5%	-2.1%	-1.3%	-29.7%
Median	--	--	$2.9M	4.5%	11.8	11.2	6.0%	$4.1B	7.1%	-2.7%	0.6%	-40.7%

Peer Group

STR	QUESTAR CORPORATION
EQT	EQUITABLE RESOURCES, INC.
NI	NISOURCE INC.
OKE	ONEOK INC
UGI	UGI CORPORATION
NFG	NATIONAL FUEL GAS COMPANY
ATG	AGL RESOURCES INC.
ATO	ATMOS ENERGY CORPORATION
EGN	ENERGEN CORPORATION
PNY	PIEDMONT NATURAL GAS COMPANY, INC.

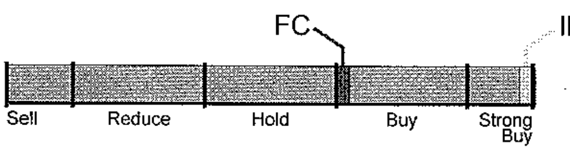
Earnings Highlights

- On 02/05/09, the company announced quarterly earnings of $0.32 per share, a positive surprise of 6.0% above the consensus $0.30. Over the past 4 quarters, the company has reported 4 positive (>2%), 0 negative(<-2%), and 0 in-line (within 2%) surprises. The average surprise for this time period has been 10.4%.
- SE's current quarter consensus estimate has decreased notably over the past 90 days from $0.46 to $0.35, a loss of -23.4%. This trails the average Gas Distribution Subsector move of -1.0% during the same time period.
- Over the past 90 days, the consensus price target for SE has decreased notably from $24.10 to $19.20, a loss of -20.3%.

Analyst Recommendations

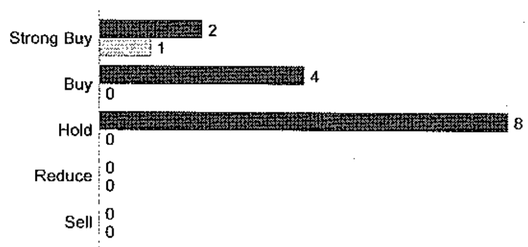
First Call Mean (FC): Buy (14 firms)

Independent Mean (IM): Strong Buy (1 firms)



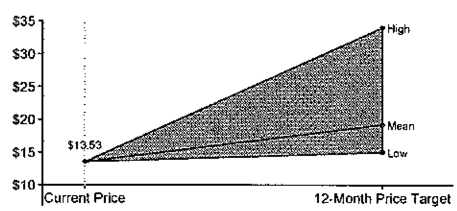
Distribution

Analysts typically rate a stock based on a five-tier scale ranging from 'Strong Buy' to 'Sell'. The chart below displays the number of analysts in each tier.



Price Target

The chart below indicates where analysts predict the stock price will be within the next 12 months, as compared to the curent price. The high, low, and mean price targets are presented.



12-Month Price Target	
Mean	$19.20
High	$34.00
Low	$15.00
Target vs. Current	41.9%
# of Analysts	12

Mean Estimate Trend

	Q 03-09	Q 06-09	Y 2009	Y 2010	Price Target
Current	$0.35	$0.17	$1.11	$1.42	$19.20
30 Days Ago	$0.40	$0.23	$1.34	$1.55	$20.70
90 Days Ago	$0.46	$0.24	$1.64	$1.67	$24.10
% Change - Last 90 Days	-23.4%	-28.4%	-32.1%	-15.1%	-20.3%

Next Expected Report Date: 05/11/09

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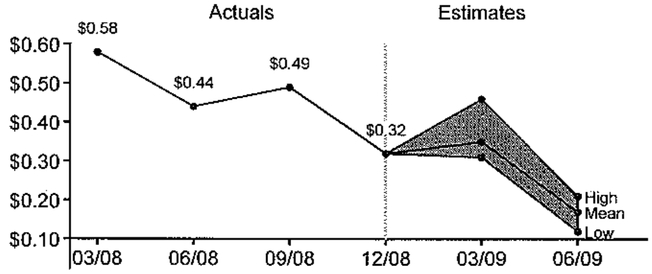
Earnings Per Share

Earnings per share (EPS) is calculated by dividing a company's earnings by the number of shares outstanding. Analysts tend to interpret a pattern of increasing earnings as a sign of strength and flat or falling earnings as a sign of weakness. The charts below provide a comparison between a company's actual and estimated EPS, including the high and low forecasts.

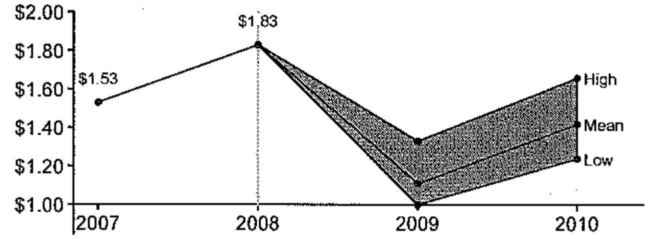
Quarterly



Estimates	03-09	06-09
FC Mean	$0.35	$0.17
High	$0.46	$0.21
Low	$0.31	$0.12
# of Analysts	9	8

NA = No Actual or Estimated EPS

Annual



Estimates	2009	2010
FC Mean	$1.11	$1.42
High	$1.33	$1.66
Low	$1.00	$1.24
# of Analysts	14	14

NA = No Actual or Estimated EPS

Earnings Surprise

Investors frequently compare a company's actual earnings to the mean expectation of professional analysts. The difference between the two is referred to as a "positive" or "negative" surprise. Academic research has shown that when a company reports a surprise, it is often followed by more of the same surprise type.

Surprise Summary - Last 3 Years

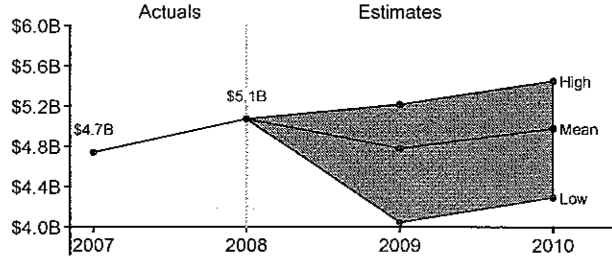
Surprise Type	#	%
Positive Quarters (> 2%)	6	75.0%
Negative Quarters (< -2%)	2	25.0%
In-Line Quarters (within 2%)	0	--

Surprise Detail - Last 6 Periods

Surprise Type	Announce Date	Period End Date	Actual EPS	Mean EPS	Surprise (%)
POSITIVE	02/05/09	12/08	$0.320	$0.302	6.0%
POSITIVE	11/06/08	09/08	$0.490	$0.458	7.0%
POSITIVE	08/06/08	06/08	$0.440	$0.420	4.8%
POSITIVE	05/06/08	03/08	$0.580	$0.468	23.9%
POSITIVE	02/06/08	12/07	$0.470	$0.383	22.7%
POSITIVE	11/06/07	09/07	$0.380	$0.287	32.4%

Annual Revenue

A pattern of increasing sales in conjunction with a rising EPS may influence a buy recommendation, while flat or falling sales and faltering earnings may explain a sell recommendation. A rising EPS with flat or falling sales may result from increased cost efficiency and margins, rather than market expansion. This chart shows the revenue forecast trend of all analysts and the highest and lowest projections for the current and next fiscal year.



	2009	2010
Mean	$4.8B	$5.0B
High	$5.2B	$5.5B
Low	$4.0B	$4.3B
Forecasted Growth	-5.7%	-1.8%
# of Analysts	7	6

NA = No Actual or Estimated Revenue

Fundamental Highlights

- The company's return on equity is at its five-year low.
- Of the 30 firms within the Gas Distribution Subsector, SPECTRA ENERGY CORP is among the 28 companies that pay a dividend. The stock's dividend yield is currently 7.0%.
- SPECTRA ENERGY CORP's current ratio of 0.5 is the lowest within its Gas Distribution Subsector.

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Fundamental Metrics

Profitability	SE	Ind Avg	Debt	SE	Ind Avg	Dividend	SE	Ind Avg
Revenue Growth For year over year ending 12/08	7.0%	15.3%	**Current Ratio** For year over year ending 12/08	0.5	1.0	**Div. Growth Rate** For year over year ending 12/08	9.1%	4.3%
Gross Margin For trailing 4 qtrs ending 12/08	13.2%	25.8%	**Debt-to-Capital** For trailing 4 qtrs ending 12/07	52.1%	48.4%	**Dividend Funding** For trailing 4 qtrs ending 12/08	33.1%	0.0%
Return on Equity For trailing 4 qtrs ending 12/08	18.2%	12.0%	**Interest Funding** For trailing 4 qtrs ending 12/08	35.2%	0.0	**Dividend Coverage** For trailing 4 qtrs ending 12/07	2.9	3.5
Net Margin For trailing 4 qtrs ending 12/08	13.6%	4.4%	**Interest Coverage** For trailing 4 qtrs ending 12/08	2.4	3.4	**Current Div. Yield** For trailing 4 qtrs ending 02/09	7.4%	0.0%

The time period stated applies to the company-level data only. The Sector Average is a simple average of the most recent data from companies whose businesses most closely match each other.

Risk Highlights

- On days when the market is up, SE tends to outperform the S&P 500 index by 81%. However, on days when the market is down, the shares generally decrease by 71% more than the S&P 500 index.
- Over the past 90 days, SE shares have been more volatile than the overall market, as the stock's daily price fluctuations have exceeded that of 37% of S&P 500 index firms.
- In both short-term and long-term periods, SE has shown high correlation (>=40%) with the S&P 500 index. Thus, this stock would provide only low levels of diversification to a portfolio similar to the broader market.

Risk Metrics

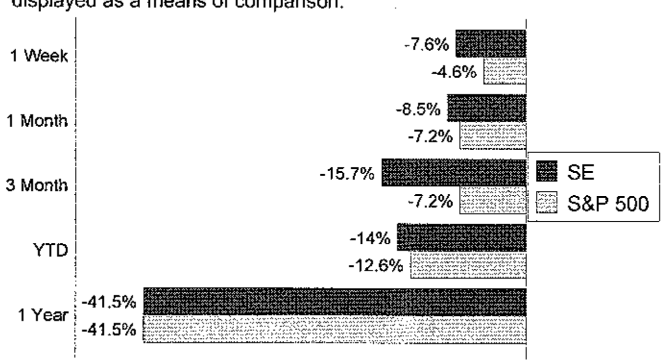
Standard Deviation		**Beta vs. S&P**	1.06	**Correlation vs. S&P**	
Last 90 Days	3.59	Positive Days Only	1.19	Last 90 Days	84%
Last 60 Months	7.38	Negative Days Only	1.14	Last 60 Months	71%
Intra-Day Swing		**Beta vs. Sector**	1.39	**Correlation vs. Sector**	
Last 90 Days Avg	5.5%	Positive Days Only	1.48	Last 90 Days	85%
Last 90 Days Largest	11.7%	Negative Days Only	1.34	Last 60 Months	71%

Price Analysis: Risk and Reward

	Last 90 Days					Last 60 Months		Last 10 Years		
Ticker	Best Daily Return	Worst Daily Return	# Days Up	# Days Down	Largest Intra-Day Swing	Best Monthly Return	Worst Monthly Return	Average February Return	Average March Return	Average April Return
SE	10.6%	-9.8%	29	30	11.7%	9.7%	-18.8%	-0.2%	0.3%	4.0%
S&P 500	6.5%	-8.9%	34	26	9.7%	5.4%	-16.9%	-1.7%	0.6%	1.8%

Price Performance

Daily closing pricing data is used to calculate the price performance of a stock over five periods. The performance of the S&P 500 is also displayed as a means of comparison.



	SE	S&P 500
Close Price (02/17/09)	$13.53	789.17
52-Week High	$29.18	1440.24
52-Week Low	$13.36	741.02

- On 02/17/09, SE closed at $13.53, 53.6% below its 52-week high and 1.3% above its 52-week low.
- SE shares are currently trading 11.2% below their 50-day moving average of $15.24, and 36.8% below their 200-day moving average of $21.42.
- The S&P 500 is currently -44.7% below its 52-week high and 4.9% above its 52-week low.

Relative Strength Indicator (scale 1-100, 100 being best)	
Last 1 Month	44
Last 3 Months	44
Last 6 Months	45

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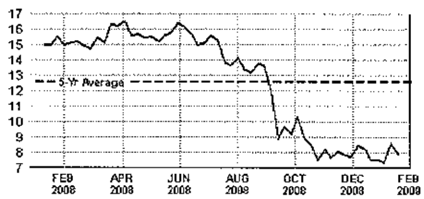
Valuation Multiples

	Trailing P/E	Forward P/E	Forward PEG
SE	7.9	13.0	2.0
S&P 500	11.9	15.1	1.5
Company Relative to Its 5-Yr Average	38% Discount	18% Discount	21% Discount
Company Relative to S&P 500	34% Discount	14% Discount	33% Premium

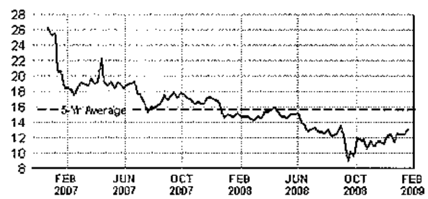
Trailing PE

Trailing P/E is calculated using the most recent closing price (updated weekly) divided by the sum of the four most recently reported quarterly earnings.



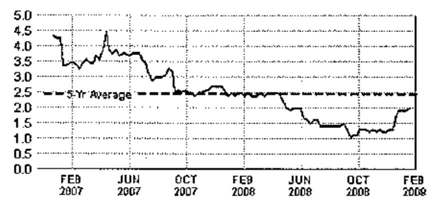
Forward PE

Forward P/E is calculated using the most recent closing price (updated weekly) divided by the sum of the four upcoming quarterly consensus estimates.



Forward PEG

Forward PEG is calculated by dividing the Forward P/E by the five-year, long term forecasted growth rate.



Insider Purchases and Sells

(Most recent transactions within the past 90 days)

No transactions for SE in the past 90 days.

Seasonal $ Sells - Quarterly & Yearly

Time-series data for each quarter over the past three years allows you to easily analyze the longer-term trend in open-market insider selling.

	Q1	Q2	Q3	Q4	Full Year
2009	$0	--	--	--	$0
2008	$0	$0	$0.80M	$0	$0.80M
2007	$0	$0	$0	$0	$0
2006	--	--	--	--	--

Seasonal $ Buys - Quarterly & Yearly

Time-series data for each quarter over the past three years allows you to easily analyze the longer-term trend in open-market insider buying.

	Q1	Q2	Q3	Q4	Full Year
2009	$0	--	--	--	$0
2008	$0.02M	$0	$0	$0	$24,139
2007	$2,825	$1.93M	$1.38M	$1.24M	$4.56M
2006	--	--	--	--	--

Institutional Holders

(Updated weekly as of 02/14/09)

The top five institutional holders are presented based on the total number of shared held.

Institution	Inst. Type	# Shares Held	Reported Date
Barrow, Hanley, Mewhinney &...	Inv Mgmt	51.8M	12/31/08
Barclays Global Investors,...	Inv Mgmt	22.4M	12/31/08
State Street Global Advisor...	Inv Mgmt	21.1M	09/30/08
T. Rowe Price Associates, Inc.	Inv Mgmt	19.9M	12/31/08
Vanguard Group, Inc.	Inv Mgmt	19.2M	12/31/08

Top Executive Holders

(Updated monthly as of 01/18/09)

The top five insider holders are presented based on the total number of direct holdings. Indirect holdings are excluded. *Please see last page for role code legend.

Insider Name	* Role	# Direct Shares	$ Value	Reported Date
Anderson, Paul M	D	0.19M	$2.88M	08/29/08
Hendrix, Dennis R	D	0.16M	$2.33M	05/13/08
Fowler, Fred J	CEO	0.13M	$1.86M	04/08/08
Wyrsch, Martha B	O	62,255	$0.92M	04/08/08
Phelps, Michael E J	D	39,854	$0.59M	05/13/08

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Distribution of Investment Ratings

As of 02/13/2009, Gradient Analytics covered 4591 companies, with 19.8% rated Buy, 61.1% rated Hold, and 19.1% rated Sell. Gradient Analytics does not engage in investment banking services.

Disclaimer

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Role Legend

AF	Affiliate	CT	CTO	R	Retired
B	Benef Owner	D	Director	SH	Shareholder
CB	Chairman	EVP	Exec VP	SVP	Sr VP
CEO	CEO	GC	Gen Counsel	T	Trustee
CFO	CFO	O	Officer	TR	Treasurer
CM	Committee Member	OH	Other	VC	Vice Chairman
CO	COO	P	President	VP	VP

Investment Methodology

Gradient Analytics, Inc (Gradient) is a private firm specializing in engineering stock rating systems and in providing independent specialized research to institutional clients. Gradient's exhaustive list of ratings include MSN/CNBC Money's StockScouter, and numerous institutional stock rating systems. Gradient also provides proprietary ratings of earnings quality, fundamental and valuation elements directly to institutional clients. Gradient was founded in 1996 by two former tenured professors, Dr. Carr Bettis and Dr. Donn Vickrey. Today the team consists of more than 30 financial engineers, research and business analysts and technology personnel.

The Gradient Opinion is an empirically-derived and historically backtested stock rating system with buy, sell and hold opinions. To develop a rating, the quantitative system analyzes a firm's earnings quality, balance sheet, and income statement, conducts technical and valuation analysis, and evaluates the transactions made by the company's management and directors (i.e. insiders).

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TC PIPELINES, LP (TCLP-O)

OIL & GAS / OIL EQUIP. & SERVICES / PIPELINES

Gradient Opinion

The Gradient Opinion, provided by Gradient Analytics Inc, is an empirically-derived and historically back-tested stock rating system with buy, sell, and hold opinions. To develop a rating the quantitative system analyzes a firm's earnings quality, balance sheet, and income statement, conducts technical and valuation analysis and evaluates the transactions made by the company's management and directors (i.e. insiders).

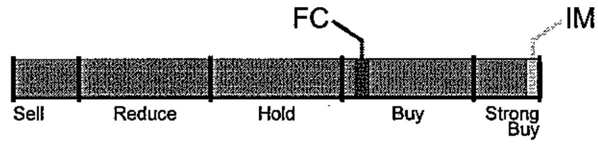
Gradient Analytics, Inc is a private independent research firm specializing in engineering institutional stock rating systems.

GRADIENT analytics

Analyst Recommendations

First Call Mean (FC): Buy (6 firms)

Independent Mean (IM): Strong Buy (1 firms)

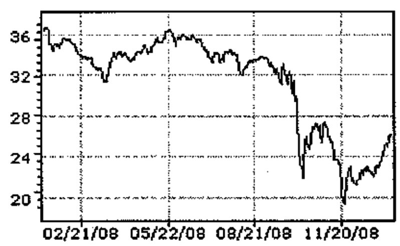


First Call Mean (FC) is the mean recommendation of all analysts covering the stock. Independent Mean (IM) is the mean recommendation of only independent analysts, which includes quantitative firms that are not included in the FC mean.

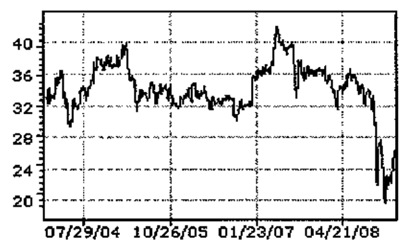
Key Information

Price (01/12/09)	$25.38
52-Week High	$37.65
52-Week Low	$18.11
Market Cap	$906M
Avg Daily Vol	82,867
Exchange	NASDAQ
Dividend Yield	11.1%
Annual Dividend	$2.82
P/E Cur Yr (12/08)	9.7
P/E Next Yr (12/09)	10.1
Forward PEG	2.1
LTG Forecast	5.0%
Exp Report Date	02/23/09
Annual Revenue	$30M
ROE	10.9%
Inst. Ownership	66.4%

1-Year Price Chart



5-Year Price Chart



Business Description

TC Pipelines, LP. The Group's principal activity is to transport natural gas. The Group has a 50% general partner interest in Northern Border Pipeline Company and a 99% general partner interest in Tuscarora Gas Transmission Company. Northern Border Pipeline Company owns a 1,249 mile interstate pipeline system that transports natural gas from the Montana-Saskatchewan border to markets in the midwestern United States. Tuscarora Gas Transmission Company owns a 240-mile, 20-inch diameter, interstate pipeline system that originates at an interconnection point with facilities of Gas Transmission Northwest Corporation near Oregon and runs southeast through northern California and northwestern Nevada. On 22-Feb-2007, the partnership acquired a 46.45 per cent interest in Great Lakes from El Paso Corporation.

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Thomson Reuters Company in Context Report for TCLP

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Peer Analysis

Ticker	Gradient Opinion	Price (01/09/09)	Market Cap	Dividend Yield	P/E Current Year	P/E Next Year	LTG Forecast	Annual Revenue	Net Margin	1-Mo Return	3-Mo Return	1-Yr Return
EEP	Hold	$28.56	$1.7B	13.6%	9.3	10.5	3.5%	$10.3B	3.7%	2.5%	5.5%	-44.1%
SXL	Hold	$48.67	$1.4B	7.8%	10.7	10.8	3.7%	$9.9B	1.0%	11.1%	67.2%	-0.7%
EPB	--	$16.15	$1.4B	7.3%	13.8	12.0	10.1%	$132M	58.8%	9.9%	25.4%	-33.1%
MGG	Hold	$16.16	$1.0B	8.6%	12.7	12.3	10.0%	$1.3B	6.2%	9.5%	15.4%	-36.9%
SEP	Buy	$19.61	$967M	7.1%	14.8	13.6	7.7%	$118M	82.4%	4.8%	33.0%	-21.1%
TCLP	**Hold**	**$25.38**	**$906M**	**10.9%**	**9.7**	**10.1**	**5.0%**	**$30M**	**306.1%**	**12.9%**	**18.3%**	**-31.3%**
NSH	Buy	$19.32	$839M	8.7%	12.7	12.0	9.7%	--	--	1.7%	36.1%	-29.1%
CPNO	Sell	$13.41	$691M	15.9%	12.2	10.7	8.5%	$1.7B	1.9%	23.1%	-21.3%	-62.2%
MWE	--	$8.98	$557M	26.0%	14.5	10.6	8.5%	$773M	6.7%	-16.7%	-41.3%	-75.1%
GEL	--	$11.44	$454M	11.5%	16.0	9.9	8.5%	$2.2B	1.6%	29.7%	27.5%	-50.1%
BGH	Hold	$14.99	$414M	8.3%	14.9	11.6	9.7%	$1.5B	1.5%	15.6%	38.3%	-47.5%
Average	--	--	$0.9M	11.5%	12.8	11.3	7.7%	$2.5B	47.0%	9.5%	18.5%	-39.2%
Median	--	--	$0.9M	9.0%	12.7	10.8	8.5%	$1.3B	5.0%	9.9%	25.4%	-36.9%

Peer Group

EEP	ENBRIDGE ENERGY PARTNERS LP
SXL	SUNOCO LOGISTICS PARTNERS LP
EPB	EL PASO PIPELINE PARTNERS, L.P.
MGG	MAGELLAN MIDSTREAM HOLDINGS, L.P.
SEP	SPECTRA ENERGY PARTNERS, LP
NSH	NUSTAR GP HOLDINGS, LLC
CPNO	COPANO ENERGY, L.L.C.
MWE	MARKWEST ENERGY PARTNERS, L.P.
GEL	GENESIS ENERGY, L.P.
BGH	BUCKEYE GP HOLDINGS L.P.

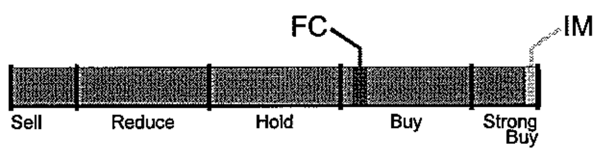
Earnings Highlights

- TCLP's current quarter consensus estimate has remained relatively unchanged over the past 90 days at $0.65. Estimates within its Subsector have moved an average of -8.0% during the same time period.
- Over the past 90 days, the consensus price target for TCLP has decreased notably from $36.90 to $30.50, a loss of -17.3%.

Analyst Recommendations

First Call Mean (FC): Buy (6 firms)

Independent Mean (IM): Strong Buy (1 firms)

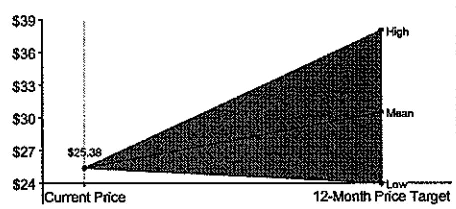


Distribution

Analysts typically rate a stock based on a five-tier scale ranging from 'Strong Buy' to 'Sell'. The chart below displays the number of analysts in each tier.

Price Target

The chart below indicates where analysts predict the stock price will be within the next 12 months, as compared to the curent price. The high, low, and mean price targets are presented.



12-Month Price Target	
Mean	$30.50
High	$38.00
Low	$24.00
Target vs. Current	20.2%
# of Analysts	5

Mean Estimate Trend

	Q 12-08	Q 03-09	Y 2008	Y 2009	Price Target
Current	$0.65	$0.84	$2.67	$2.57	$30.50
30 Days Ago	$0.65	$0.84	$2.67	$2.57	$31.80
90 Days Ago	$0.64	$0.86	$2.61	$2.61	$36.90
% Change - Last 90 Days	0.8%	-2.3%	2.1%	-1.4%	-17.3%

Next Expected Report Date: 02/23/09

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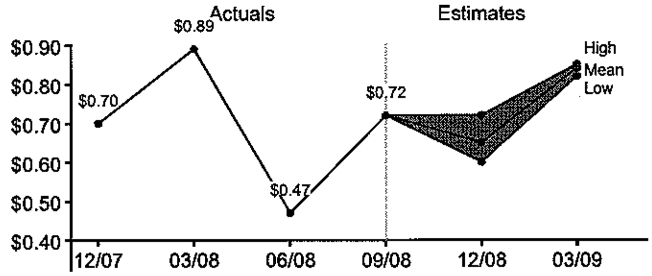
Earnings Per Share

Earnings per share (EPS) is calculated by dividing a company's earnings by the number of shares outstanding. Analysts tend to interpret a pattern of increasing earnings as a sign of strength and flat or falling earnings as a sign of weakness. The charts below provide a comparison between a company's actual and estimated EPS, including the high and low forecasts.

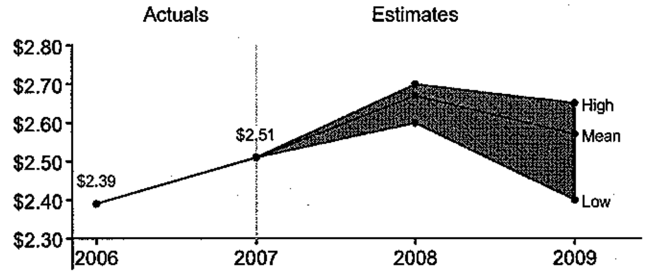
Quarterly



Estimates	12-08	03-09
FC Mean	$0.65	$0.84
High	$0.72	$0.85
Low	$0.60	$0.82
# of Analysts	4	2

NA = No Actual or Estimated EPS

Annual



Estimates	2008	2009
FC Mean	$2.67	$2.57
High	$2.70	$2.65
Low	$2.60	$2.40
# of Analysts	3	6

NA = No Actual or Estimated EPS

Earnings Surprise

Investors frequently compare a company's actual earnings to the mean expectation of professional analysts. The difference between the two is referred to as a "positive" or "negative" surprise. Academic research has shown that when a company reports a surprise, it is often followed by more of the same surprise type.

Surprise Summary - Last 3 Years

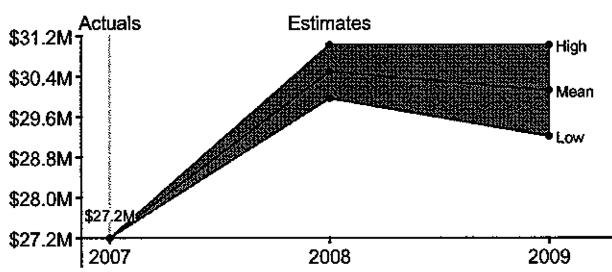
Surprise Type	#	%
Positive Quarters (> 2%)	5	41.7%
Negative Quarters (< -2%)	6	50.0%
In-Line Quarters (within 2%)	1	8.3%

Surprise Detail - Last 6 Periods

Surprise Type	Announce Date	Period End Date	Actual EPS	Mean EPS	Surprise (%)
POSITIVE	10/31/08	09/08	$0.720	$0.578	24.6%
NEGATIVE	07/31/08	06/08	$0.470	$0.530	-11.3%
POSITIVE	04/24/08	03/08	$0.890	$0.692	28.6%
POSITIVE	02/22/08	12/07	$0.700	$0.623	12.4%
POSITIVE	11/01/07	09/07	$0.640	$0.548	16.8%
NEGATIVE	08/02/07	06/07	$0.450	$0.482	-6.6%

Annual Revenue

A pattern of increasing sales in conjunction with a rising EPS may influence a buy recommendation, while flat or falling sales and faltering earnings may explain a sell recommendation. A rising EPS with flat or falling sales may result from increased cost efficiency and margins, rather than market expansion. This chart shows the revenue forecast trend of all analysts and the highest and lowest projections for the current and next fiscal year.



	2008	2009
Mean	$31M	$30M
High	$31M	$31M
Low	$30M	$29M
Forecasted Growth	12.1%	10.8%
# of Analysts	2	2

NA = No Actual or Estimated Revenue

Fundamental Highlights

- TCLP's net margin (trailing 4 quarters) of 306.1% is the highest within its Pipelines Subsector.
- Of the 44 firms within the Pipelines Subsector, TC PIPELINES, LP is among the 37 companies that pay a dividend. The stock's dividend yield is currently 10.9%.
- TC PIPELINES, LP's interest coverage (number of times interest payments are covered by EBIT) of 0.5 is substantially below the Pipelines Subsector average of 3.3.

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Fundamental Metrics

Profitability	TCLP	Ind Avg	Debt	TCLP	Ind Avg	Dividend	TCLP	Ind Avg
Revenue Growth For year over year ending 09/08	42.5%	49.5%	**Current Ratio** For year over year ending 09/08	1.4	1.0	**Div. Growth Rate** For year over year ending 09/08	9.0%	13.0%
Gross Margin For trailing 4 qtrs ending 06/08	78.0%	22.6%	**Debt-to-Capital** For trailing 4 qtrs ending 12/07	38.7%	50.6%	**Dividend Funding** For trailing 4 qtrs ending 09/08	110.3%	0.0%
Return on Equity For trailing 4 qtrs ending 09/08	10.9%	10.9%	**Interest Funding** For trailing 4 qtrs ending 09/08	36.0%	0.0	**Dividend Coverage** For trailing 4 qtrs ending 12/07	1.1	1.6
Net Margin For trailing 4 qtrs ending 09/08	306.1%	6.7%	**Interest Coverage** For trailing 4 qtrs ending 09/08	0.5	3.3	**Current Div. Yield** For trailing 4 qtrs ending 01/09	11.1%	0.0%

The time period stated applies to the company-level data only. The Sector Average is a simple average of the most recent data from companies whose businesses most closely match each other.

Risk Highlights

- On days when the market is up, TCLP tends to underperform the S&P 500 index by 34%. On days when the market is down, the shares generally decrease by 36% less than the S&P 500 index.
- Over the past 90 days, TCLP shares have been more volatile than the overall market, as the stock's daily price fluctuations have exceeded that of 12% of S&P 500 index firms.
- In both short-term and long-term periods, TCLP has shown high correlation (>=40%) with the S&P 500 index. Thus, this stock would provide only low levels of diversification to a portfolio similar to the broader market.

Risk Metrics

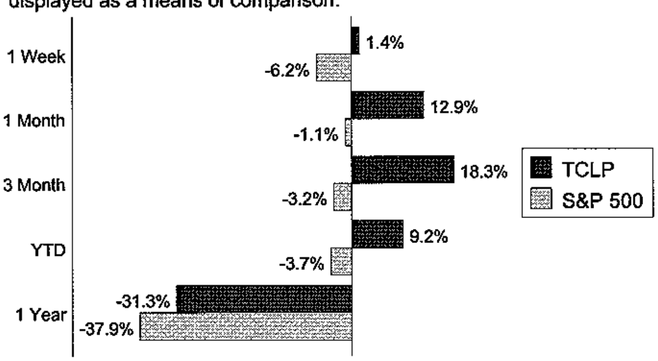
Standard Deviation		**Beta vs. S&P**	0.51	**Correlation vs. S&P**	
Last 90 Days	3.62	Positive Days Only	0.51	Last 90 Days	64%
Last 60 Months	5.30	Negative Days Only	0.68	Last 60 Months	53%
Intra-Day Swing		**Beta vs. Sector**	0.50	**Correlation vs. Sector**	
Last 90 Days Avg	6.2%	Positive Days Only	0.56	Last 90 Days	75%
Last 90 Days Largest	16.0%	Negative Days Only	0.62	Last 60 Months	52%

Price Analysis: Risk and Reward

	Last 90 Days					Last 60 Months		Last 10 Years		
Ticker	Best Daily Return	Worst Daily Return	# Days Up	# Days Down	Largest Intra-Day Swing	Best Monthly Return	Worst Monthly Return	Average January Return	Average February Return	Average March Return
TCLP	15.0%	-10.9%	32	29	16.0%	13.8%	-16.4%	2.7%	0.4%	-1.2%
S&P 500	11.6%	-9.0%	30	32	10.4%	5.4%	-16.9%	-0.6%	-1.7%	0.6%

Price Performance

Daily closing pricing data is used to calculate the price performance of a stock over five periods. The performance of the S&P 500 is also displayed as a means of comparison.



	TCLP	S&P 500
Close Price (01/12/09)	$25.38	870.26
52-Week High	$37.65	1440.24
52-Week Low	$18.11	741.02

- On 01/12/09, TCLP closed at $25.38, 32.6% below its 52-week high and 40.1% above its 52-week low.
- TCLP shares are currently trading 11.3% above their 50-day moving average of $22.80, and 16.9% below their 200-day moving average of $30.55.
- The S&P 500 is currently -39.0% below its 52-week high and 15.7% above its 52-week low.

Relative Strength Indicator (scale 1-100, 100 being best)	
Last 1 Month	61
Last 3 Months	49
Last 6 Months	46

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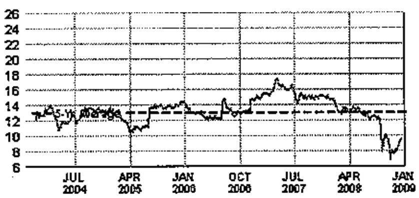
Valuation Multiples

	Trailing P/E	Forward P/E	Forward PEG
TCLP	9.4	10.5	2.1
S&P 500	12.2	14.5	1.4
Company Relative to Its 5-Yr Average	29% Discount	23% Discount	32% Discount
Company Relative to S&P 500	23% Discount	28% Discount	47% Premium

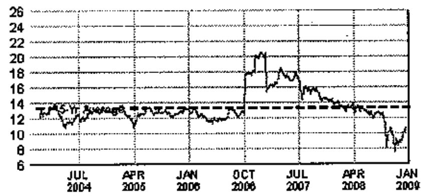
Trailing PE

Trailing P/E is calculated using the most recent closing price (updated weekly) divided by the sum of the four most recently reported quarterly earnings.



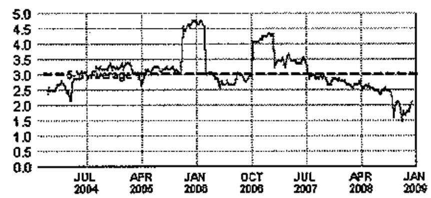
Forward PE

Forward P/E is calculated using the most recent closing price (updated weekly) divided by the sum of the four upcoming quarterly consensus estimates.



Forward PEG

Forward PEG is calculated by dividing the Forward P/E by the five-year, long term forecasted growth rate.



Insider Purchases and Sells

(Most recent transactions within the past 90 days)

No transactions for TCLP in the past 90 days.

Seasonal $ Sells - Quarterly & Yearly

Time-series data for each quarter over the past three years allows you to easily analyze the longer-term trend in open-market insider selling.

	Q1	Q2	Q3	Q4	Full Year
2009	$0	--	--	--	$0
2008	$0	$0	$0.01M	$0	$14,945
2007	$0	$0	$0	$0.02M	$23,317
2006	$0.04M	$0	$0	$0	$40,800

Seasonal $ Buys - Quarterly & Yearly

Time-series data for each quarter over the past three years allows you to easily analyze the longer-term trend in open-market insider buying.

	Q1	Q2	Q3	Q4	Full Year
2009	$0	--	--	--	$0
2008	$0	$0	$0	$0	$0
2007	$0	$0	$0.26M	$0	$0.26M
2006	$0	$0	$0	$0	$0

Institutional Holders

(Updated weekly as of 01/10/09)

The top five institutional holders are presented based on the total number of shared held.

Institution	Inst. Type	# Shares Held	Reported Date
Transcanada Pipelines Ltd	Strategic	10.7M	02/25/08
Tortoise Capital Advisors, LLC	Inv Mgmt	2.40M	09/30/08
Kayne Anderson Capital Advi...	Inv Mgmt	2.39M	09/30/08
Goldman Sachs & Company, Inc.	Brokerag	1.27M	09/30/08
Argyll Research, LLC	Inv Mgmt	0.92M	09/30/08

Top Executive Holders

(Updated monthly as of 11/16/08)

The top five insider holders are presented based on the total number of direct holdings. Indirect holdings are excluded. *Please see last page for role code legend.

Insider Name	* Role	# Direct Shares	$ Value	Reported Date
Girling, Russell K	CEO	6,000	$0.14M	08/14/07
Jenkins, Stark John F	D	4,933	$0.12M	08/16/07
Marshall, David L	D	450	$10,575	11/05/07

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Distribution of Investment Ratings

As of 01/09/2009, Gradient Analytics covered 4584 companies, with 20.6% rated Buy, 60.2% rated Hold, and 19.2% rated Sell. Gradient Analytics does not engage in investment banking services.

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Role Legend

AF	Affiliate	CT	CTO	R	Retired
B	Benef Owner	D	Director	SH	Shareholder
CB	Chairman	EVP	Exec VP	SVP	Sr VP
CEO	CEO	GC	Gen Counsel	T	Trustee
CFO	CFO	O	Officer	TR	Treasurer
CM	Committee Member	OH	Other	VC	Vice Chairman
CO	COO	P	President	VP	VP

Investment Methodology

Gradient Analytics, Inc (Gradient) is a private firm specializing in engineering stock rating systems and in providing independent specialized research to institutional clients. Gradient's exhaustive list of ratings include MSN/CNBC Money's StockScouter, and numerous institutional stock rating systems. Gradient also provides proprietary ratings of earnings quality, fundamental and valuation elements directly to institutional clients. Gradient was founded in 1996 by two former tenured professors, Dr. Carr Bettis and Dr. Donn Vickrey. Today the team consists of more than 30 financial engineers, research and business analysts and technology personnel.

The Gradient Opinion is an empirically-derived and historically backtested stock rating system with buy, sell and hold opinions. To develop a rating, the quantitative system analyzes a firm's earnings quality, balance sheet, and income statement, conducts technical and valuation analysis, and evaluates the transactions made by the company's management and directors (i.e. insiders).

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WILLIAMS COMPANIES, INC. (THE) (WMB-N)

OIL & GAS / OIL EQUIP. & SERVICES / PIPELINES

Gradient Opinion

Buy
▶ Hold
Sell

The Gradient Opinion, provided by Gradient Analytics Inc, is an empirically-derived and historically back-tested stock rating system with buy, sell, and hold opinions. To develop a rating the quantitative system analyzes a firm's earnings quality, balance sheet, and income statement, conducts technical and valuation analysis and evaluates the transactions made by the company's management and directors (i.e. insiders).

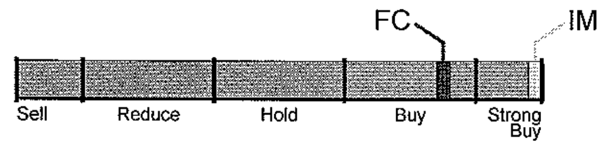
Gradient Analytics, Inc is a private independent research firm specializing in engineering institutional stock rating systems.

GRADIENT analytics

Analyst Recommendations

First Call Mean (FC): Buy (11 firms)

Independent Mean (IM): Strong Buy (1 firms)

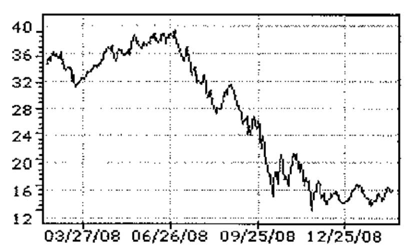


First Call Mean (FC) is the mean recommendation of all analysts covering the stock. Independent Mean (IM) is the mean recommendation of only independent analysts, which includes quantitative firms that are not included in the FC mean.

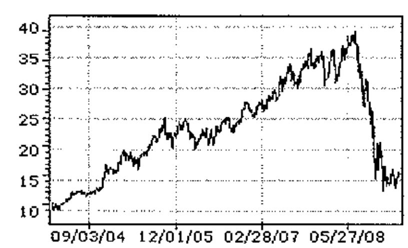
Key Information

Price (02/17/09)	$14.16
52-Week High	$40.75
52-Week Low	$11.69
Market Cap	$9.1B
Avg Daily Vol	10.1M
Exchange	NYSE
Dividend Yield	3.1%
Annual Dividend	$0.44
P/E Cur Yr (12/08)	7.2
P/E Next Yr (12/09)	12.0
Forward PEG	0.9
LTG Forecast	15.0%
Exp Report Date	02/25/09
Annual Revenue	$12.7B
ROE	20.3%
Inst. Ownership	80.3%

1-Year Price Chart



5-Year Price Chart



Business Description

Williams Companies, Inc. (The). The Group's principal activities are to find, produce, gather, process and transport natural gas. The Group operates in four segments: Gas Pipelines, Exploration and Production, Midstream gas and Liquids and Power. Gas pipeline segment consists of two interstate natural gas pipeline systems as well as investments in natural gas pipeline-related companies. Exploration and Production segment includes natural gas exploration, production gas management activities in Rocky Mountain and Mid Continent regions of the United States and Argentina. Midstream Gas and Liquids segment owns and operates gas gathering and processing facilities in the United States. Power segment is an energy services provider that buys, sells, stores, and transports a full suite of energy-related commodities, including power, natural gas, crude oil, refined products and emission credits, primarily on a wholesale level.

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Thomson Reuters Company in Context Report for WMB

- Updated February 18, 2009

Peer Analysis

Ticker	Gradient Opinion	Price (01/13/09)	Market Cap	Dividend Yield	P/E Current Year	P/E Next Year	LTG Forecast	Annual Revenue	Net Margin	1-Mo Return	3-Mo Return	1-Yr Return
EPD	--	$22.55	$10.0B	9.1%	13.3	12.6	7.5%	$21.9B	5.3%	2.5%	3.5%	-27.8%
WMB	**Hold**	**$14.16**	**$9.1B**	**2.9%**	**7.2**	**12.0**	**15.0%**	**$12.7B**	**11.2%**	**1.1%**	**-15.2%**	**-58.5%**
KMP	Hold	$48.88	$8.9B	8.3%	27.8	22.1	6.0%	$11.9B	3.8%	1.4%	-0.7%	-15.7%
EP	Hold	$8.39	$6.3B	2.2%	7.1	7.9	6.3%	$4.9B	16.6%	3.7%	18.2%	-49.3%
ETP	Buy	$35.30	$5.4B	10.0%	9.8	8.7	6.6%	$7.1B	7.3%	-1.8%	7.1%	-28.4%
PAA	Hold	$39.69	$4.7B	--	13.4	13.5	5.8%	$31.6B	2.0%	5.1%	19.6%	-17.0%
ETE	Buy	$18.75	$4.1B	10.4%	10.6	8.8	11.3%	$8.6B	4.8%	9.9%	11.7%	-41.4%
KMR	Hold	$42.95	$3.4B	--	20.7	25.9	5.5%	--	--	2.6%	-0.9%	-17.2%
EPE	Hold	$21.78	$2.8B	8.3%	14.6	16.2	7.5%	$37.9B	0.4%	11.0%	13.6%	-31.1%
NS	Hold	$47.21	$2.6B	8.7%	12.3	11.7	6.4%	$4.3B	7.8%	4.3%	13.4%	-12.7%
TPP	Hold	$23.01	$2.5B	12.1%	13.8	13.0	8.1%	$12.6B	0.9%	-4.0%	-5.7%	-39.5%
Average	--	--	$5.4M	7.9%	13.7	13.9	7.8%	$14.0B	6.0%	3.3%	5.9%	-30.8%
Median	--	--	$4.7M	9.0%	13.3	12.6	6.6%	$11.9B	5.1%	2.6%	7.1%	-28.4%

Peer Group

EPD	ENTERPRISE PRODUCTS PARTNERS LP
KMP	KINDER MORGAN ENERGY PARTNERS, L.P.
EP	EL PASO CORPORATION
ETP	ENERGY TRANSFER PARTNERS, LP
PAA	PLAINS ALL AMERICAN PIPELINE, L.P.
ETE	ENERGY TRANSFER EQUITY, L.P.
KMR	KINDER MORGAN MANAGEMENT LLC
EPE	ENTERPRISE GP HOLDINGS L.P.
NS	NUSTAR ENERGY L P
TPP	TEPPCO PARTNERS, L.P.

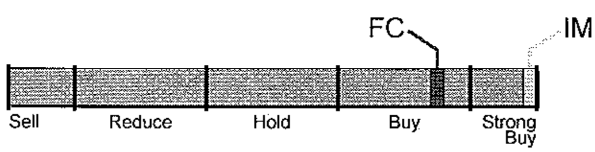
Earnings Highlights

- WMB's current quarter consensus estimate has decreased notably over the past 90 days from $0.39 to $0.30, a loss of -23.9%. This trails the average Pipelines Subsector move of -8.0% during the same time period.
- Over the past 90 days, the consensus price target for WMB has decreased notably from $34.90 to $23.40, a loss of -33.0%.
- During the past four weeks, analysts covering WMB have made 1 upward and 4 downward EPS estimate revisions for the current quarter.

Analyst Recommendations

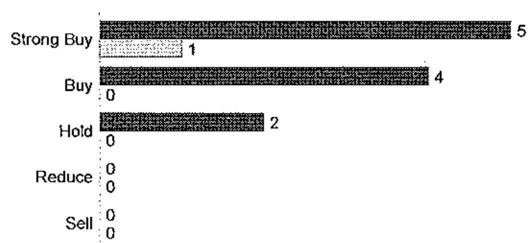
First Call Mean (FC): Buy (11 firms)

Independent Mean (IM): Strong Buy (1 firms)



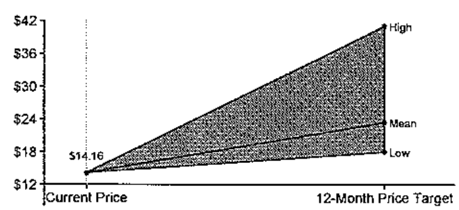
Distribution

Analysts typically rate a stock based on a five-tier scale ranging from 'Strong Buy' to 'Sell'. The chart below displays the number of analysts in each tier.



Price Target

The chart below indicates where analysts predict the stock price will be within the next 12 months, as compared to the curent price. The high, low, and mean price targets are presented.



12-Month Price Target	
Mean	$23.40
High	$41.00
Low	$18.00
Target vs. Current	65.3%
# of Analysts	8

Mean Estimate Trend

	Q 12-08	Q 03-09	Y 2008	Y 2009	Price Target
Current	$0.30	$0.29	$2.14	$1.28	$23.40
30 Days Ago	$0.33	$0.44	$2.15	$1.58	$25.80
90 Days Ago	$0.39	$0.47	$2.27	$1.95	$34.90
% Change - Last 90 Days	-23.9%	-38.7%	-5.7%	-34.3%	-33.0%

Next Expected Report Date: 02/25/09

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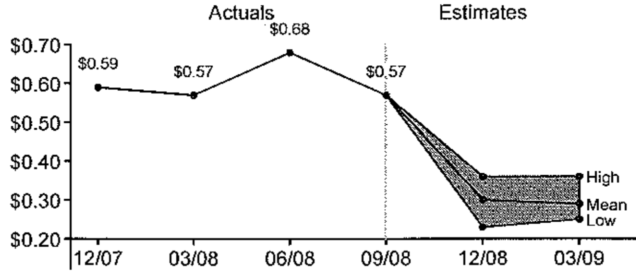
Thomson Reuters Company in Context Report for WMB

- Updated February 18, 2009

Earnings Per Share

Earnings per share (EPS) is calculated by dividing a company's earnings by the number of shares outstanding. Analysts tend to interpret a pattern of increasing earnings as a sign of strength and flat or falling earnings as a sign of weakness. The charts below provide a comparison between a company's actual and estimated EPS, including the high and low forecasts.

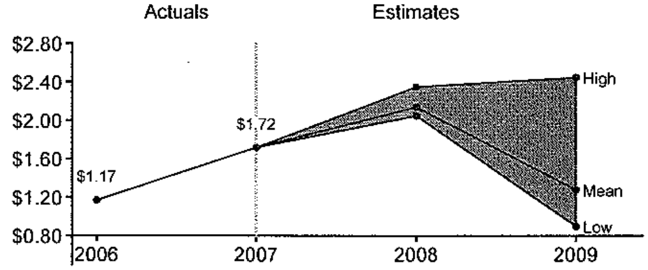
Quarterly



Estimates	12-08	03-09
FC Mean	$0.30	$0.29
High	$0.36	$0.36
Low	$0.23	$0.25
# of Analysts	10	4

NA = No Actual or Estimated EPS

Annual



Estimates	2008	2009
FC Mean	$2.14	$1.28
High	$2.35	$2.45
Low	$2.05	$0.90
# of Analysts	8	12

NA = No Actual or Estimated EPS

Earnings Surprise

Investors frequently compare a company's actual earnings to the mean expectation of professional analysts. The difference between the two is referred to as a "positive" or "negative" surprise. Academic research has shown that when a company reports a surprise, it is often followed by more of the same surprise type.

Surprise Summary - Last 3 Years

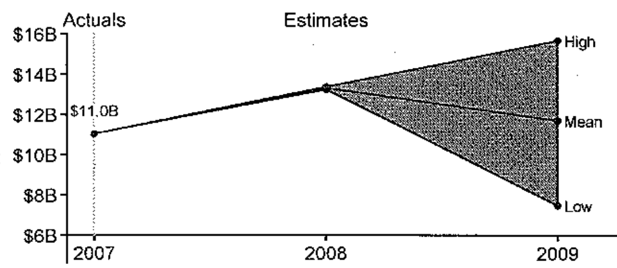
Surprise Type	#	%
Positive Quarters (> 2%)	7	58.3%
Negative Quarters (< -2%)	3	25.0%
In-Line Quarters (within 2%)	2	16.7%

Surprise Detail - Last 6 Periods

Surprise Type	Announce Date	Period End Date	Actual EPS	Mean EPS	Surprise (%)
NEGATIVE	11/06/08	09/08	$0.570	$0.649	-12.2%
IN-LINE	08/07/08	06/08	$0.680	$0.691	-1.6%
POSITIVE	05/01/08	03/08	$0.570	$0.524	8.8%
POSITIVE	02/21/08	12/07	$0.590	$0.477	23.7%
POSITIVE	11/01/07	09/07	$0.390	$0.375	4.0%
POSITIVE	08/02/07	06/07	$0.430	$0.357	20.5%

Annual Revenue

A pattern of increasing sales in conjunction with a rising EPS may influence a buy recommendation, while flat or falling sales and faltering earnings may explain a sell recommendation. A rising EPS with flat or falling sales may result from increased cost efficiency and margins, rather than market expansion. This chart shows the revenue forecast trend of all analysts and the highest and lowest projections for the current and next fiscal year.



	2008	2009
Mean	$13.3B	$11.7B
High	$13.4B	$15.7B
Low	$13.2B	$7.5B
Forecasted Growth	20.6%	6.0%
# of Analysts	2	5

NA = No Actual or Estimated Revenue

Fundamental Highlights

- WILLIAMS COMPANIES, INC. (THE)'s net margin (trailing 4 quarters) of 11.2% is substantially above the Pipelines Subsector average of 6.7%.
- Of the 43 firms within the Pipelines Subsector, WILLIAMS COMPANIES, INC. (THE) is among the 37 companies that pay a dividend. The stock's dividend yield is currently 2.9%.
- WILLIAMS COMPANIES, INC. (THE)'s interest coverage (number of times interest payments are covered by EBIT) of 4.8 is substantially above the Pipelines Subsector average of 3.4.

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Fundamental Metrics

Profitability	WMB	Ind Avg	Debt	WMB	Ind Avg	Dividend	WMB	Ind Avg
Revenue Growth For year over year ending 09/08	17.6%	43.5%	**Current Ratio** For year over year ending 09/08	1.3	1.0	**Div. Growth Rate** For year over year ending 09/08	10.5%	12.2%
Gross Margin For trailing 4 qtrs ending 09/08	27.0%	22.6%	**Debt-to-Capital** For trailing 4 qtrs ending 12/07	49.8%	50.6%	**Dividend Funding** For trailing 4 qtrs ending 09/08	9.4%	0.0%
Return on Equity For trailing 4 qtrs ending 09/08	20.3%	10.9%	**Interest Funding** For trailing 4 qtrs ending 09/08	25.6%	0.0	**Dividend Coverage** For trailing 4 qtrs ending 12/07	10.2	1.6
Net Margin For trailing 4 qtrs ending 09/08	11.2%	6.7%	**Interest Coverage** For trailing 4 qtrs ending 09/08	4.8	3.4	**Current Div. Yield** For trailing 4 qtrs ending 02/09	3.1%	0.0%

The time period stated applies to the company-level data only. The Sector Average is a simple average of the most recent data from companies whose businesses most closely match each other.

Risk Highlights

- On days when the market is up, WMB tends to outperform the S&P 500 index by 88%. However, on days when the market is down, the shares generally decrease by 90% more than the S&P 500 index.
- Over the past 90 days, the daily price fluctuations of WMB have been in-line with the S&P 500 index firms.
- In both short-term and long-term periods, WMB has shown high correlation (>=40%) with the S&P 500 index. Thus, this stock would provide only low levels of diversification to a portfolio similar to the broader market.

Risk Metrics

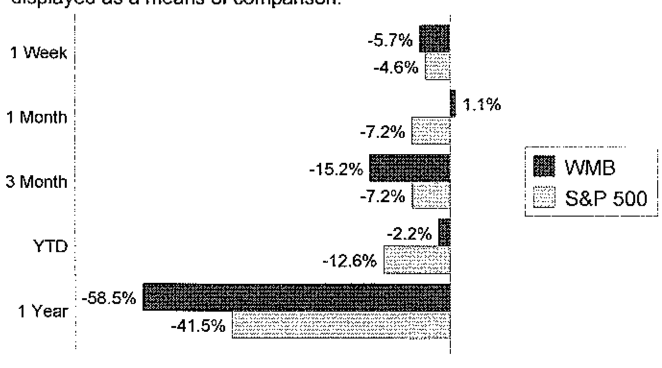
Standard Deviation		**Beta vs. S&P**	1.40	**Correlation vs. S&P**	
Last 90 Days	5.32	Positive Days Only	1.37	Last 90 Days	84%
Last 60 Months	8.78	Negative Days Only	1.63	Last 60 Months	55%
Intra-Day Swing		**Beta vs. Sector**	1.17	**Correlation vs. Sector**	
Last 90 Days Avg	7.4%	Positive Days Only	1.15	Last 90 Days	89%
Last 90 Days Largest	18.5%	Negative Days Only	1.21	Last 60 Months	69%

Price Analysis: Risk and Reward

	Last 90 Days					Last 60 Months		Last 10 Years		
Ticker	Best Daily Return	Worst Daily Return	# Days Up	# Days Down	Largest Intra-Day Swing	Best Monthly Return	Worst Monthly Return	Average February Return	Average March Return	Average April Return
WMB	16.1%	-16.5%	33	26	18.5%	33.2%	-23.4%	2.8%	7.8%	3.9%
S&P 500	6.5%	-8.9%	34	26	9.7%	5.4%	-16.9%	-1.7%	0.6%	1.8%

Price Performance

Daily closing pricing data is used to calculate the price performance of a stock over five periods. The performance of the S&P 500 is also displayed as a means of comparison.



	WMB	S&P 500
Close Price (02/17/09)	$14.16	789.17
52-Week High	$40.75	1440.24
52-Week Low	$11.69	741.02

- On 02/17/09, WMB closed at $14.16, 65.3% below its 52-week high and 21.1% above its 52-week low.
- WMB shares are currently trading 2.3% below their 50-day moving average of $14.50, and 42.2% below their 200-day moving average of $24.48.
- The S&P 500 is currently -44.7% below its 52-week high and 4.9% above its 52-week low.

Relative Strength Indicator (scale 1-100, 100 being best)	
Last 1 Month	52
Last 3 Months	46
Last 6 Months	45

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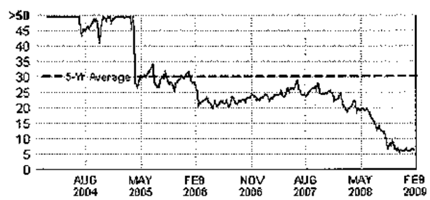
Valuation Multiples

	Trailing P/E	Forward P/E	Forward PEG
WMB	6.4	12.8	.9
S&P 500	11.9	15.1	1.5
Company Relative to Its 5-Yr Average	80% Discount	36% Discount	43% Discount
Company Relative to S&P 500	47% Discount	15% Discount	43% Discount

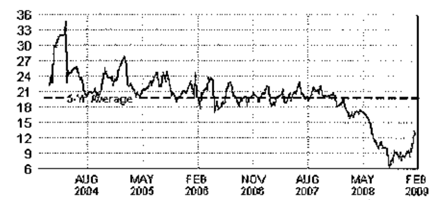
Trailing PE

Trailing P/E is calculated using the most recent closing price (updated weekly) divided by the sum of the four most recently reported quarterly earnings.



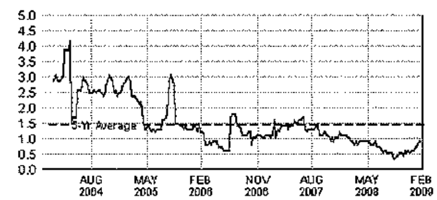
Forward PE

Forward P/E is calculated using the most recent closing price (updated weekly) divided by the sum of the four upcoming quarterly consensus estimates.



Forward PEG

Forward PEG is calculated by dividing the Forward P/E by the five-year, long term forecasted growth rate.



Insider Purchases and Sells

(Most recent transactions within the past 90 days)

Name	Role	Tran Date	Tran Type	Shares
Green, William E	Director	12/16/08-12/16/08	Sale	$4,000
Bender, James J	Gen Counsel	12/12/08-12/15/08	Sale	$12,111

Seasonal $ Sells - Quarterly & Yearly

Time-series data for each quarter over the past three years allows you to easily analyze the longer-term trend in open-market insider selling.

	Q1	Q2	Q3	Q4	Full Year
2009	$0	--	--	--	$0
2008	$1.72M	$6.49M	$0	$0.24M	$8.44M
2007	$2.12M	$2.91M	$6.37M	$7.13M	$18.5M
2006	$0.23M	$0.82M	$1.18M	$0.63M	$2.86M

Seasonal $ Buys - Quarterly & Yearly

Time-series data for each quarter over the past three years allows you to easily analyze the longer-term trend in open-market insider buying.

	Q1	Q2	Q3	Q4	Full Year
2009	$0	--	--	--	$0
2008	$0	$0	$0.53M	$0	$0.53M
2007	$0	$0	$0	$0	$0
2006	$7,746	$0	$0.15M	$0.01M	$0.17M

Institutional Holders

(Updated weekly as of 02/14/09)

The top five institutional holders are presented based on the total number of shared held.

Institution	Inst. Type	# Shares Held	Reported Date
Barclays Global Investors, ...	Inv Mgmt	32.7M	12/31/08
Fidelity Management & Research	Inv Mgmt	31.5M	09/30/08
State Street Global Advisor...	Inv Mgmt	23.4M	09/30/08
Vanguard Group, Inc.	Inv Mgmt	18.7M	12/31/08
Icahn Associates Corporation	Inv Mgmt	17.5M	12/31/08

Top Executive Holders

(Updated monthly as of 01/18/09)

The top five insider holders are presented based on the total number of direct holdings. Indirect holdings are excluded. *Please see last page for role code legend.

Insider Name	* Role	# Direct Shares	$ Value	Reported Date
Malcolm, Steven J	CEO	0.53M	$7.44M	03/28/08
Wright, Phillip D	O	0.14M	$1.91M	07/02/08
Chappel, Donald R	CFO	0.10M	$1.43M	03/17/08
Macinnis, Frank T	D	52,761	$0.74M	07/02/08
Howell, William R III	D	50,520	$0.71M	06/16/08

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Distribution of Investment Ratings

As of 02/13/2009, Gradient Analytics covered 4591 companies, with 19.8% rated Buy, 61.1% rated Hold, and 19.1% rated Sell. Gradient Analytics does not engage in investment banking services.

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Role Legend

AF	Affiliate	CT	CTO	R	Retired
B	Benef Owner	D	Director	SH	Shareholder
CB	Chairman	EVP	Exec VP	SVP	Sr VP
CEO	CEO	GC	Gen Counsel	T	Trustee
CFO	CFO	O	Officer	TR	Treasurer
CM	Committee Member	OH	Other	VC	Vice Chairman
CO	COO	P	President	VP	VP

Investment Methodology

Gradient Analytics, Inc (Gradient) is a private firm specializing in engineering stock rating systems and in providing independent specialized research to institutional clients. Gradient's exhaustive list of ratings include MSN/CNBC Money's StockScouter, and numerous institutional stock rating systems. Gradient also provides proprietary ratings of earnings quality, fundamental and valuation elements directly to institutional clients. Gradient was founded in 1996 by two former tenured professors, Dr. Carr Bettis and Dr. Donn Vickrey. Today the team consists of more than 30 financial engineers, research and business analysts and technology personnel.

The Gradient Opinion is an empirically-derived and historically backtested stock rating system with buy, sell and hold opinions. To develop a rating, the quantitative system analyzes a firm's earnings quality, balance sheet, and income statement, conducts technical and valuation analysis, and evaluates the transactions made by the company's management and directors (i.e. insiders).

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BWP 10-Q 9/30/2008

Section 1: 10-Q (FORM 10-Q SEPTEMBER 30, 2008)

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

(Mark One)
☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the quarterly period ended September 30, 2008

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from _______________ to _______________

Commission file number: 01-32665

BOARDWALK PIPELINE PARTNERS, LP
(Exact name of registrant as specified in its charter)

DELAWARE
(State or other jurisdiction of incorporation or organization)

20-3265614
(I.R.S. Employer Identification No.)

9 Greenway Plaza, Suite 2800
Houston, Texas 77046
(866) 913-2122

(Address and Telephone Number of Registrant's Principal Executive Office)
Securities registered pursuant to Section 12(b) of the Act:

Title of each class	*Name of each exchange on which registered*
Common Units Representing Limited Partner Interests	**New York Stock Exchange**

Securities registered pursuant to Section 12(g) of the Act: **NONE**

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one)
Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☒

As of October 17, 2008, the registrant had 100,656,122 common units, 22,866,667 class B units and 33,093,878 subordinated units outstanding.

TABLE OF CONTENTS

FORM 10-Q

September 30, 2008

BOARDWALK PIPELINE PARTNERS, LP

PART I - FINANCIAL INFORMATION

PART I I - OTHER INFORMATION

PART I – FINANCIAL INFORMATION

Item 1. Financial Statements

BOARDWALK PIPELINE PARTNERS, LP

CONDENSED CONSOLIDATED BALANCE SHEETS
(Millions)
(Unaudited)

ASSETS	September 30, 2008	December 31, 2007
Current Assets:		
Cash and cash equivalents	$ 22.1	$ 317.3
Receivables:		
Trade, net	56.9	60.7
Other	9.4	12.7
Gas Receivables:		
Transportation and exchange	25.6	12.5
Storage	-	1.3
Inventories	17.9	16.6
Costs recoverable from customers	5.8	6.3
Gas stored underground	3.6	16.3
Prepaid expenses and other current assets	22.3	11.9
Total current assets	163.6	455.6
Property, Plant and Equipment:		
Natural gas transmission plant	3,484.6	2,392.5
Other natural gas plant	221.2	224.0
	3,705.8	2,616.5
Less—accumulated depreciation and amortization	349.8	262.5
	3,356.0	2,354.0
Construction work in progress	1,941.0	951.4
Property, plant and equipment, net	5,297.0	3,305.4
Other Assets:		
Goodwill	163.5	163.5
Gas stored underground	174.6	172.4
Costs recoverable from customers	15.6	15.9
Other	57.3	44.5
Total other assets	411.0	396.3
Total Assets	$ 5,871.6	$ 4,157.3

The accompanying notes are an integral part of these condensed consolidated financial statements.

BOARDWALK PIPELINE PARTNERS, LP

CONDENSED CONSOLIDATED BALANCE SHEETS
(Millions)
(Unaudited)

LIABILITIES AND PARTNERS' CAPITAL	**September 30, 2008**	**December 31, 2007**
Current Liabilities:		
Payables:		
Trade	$ 306.8	$ 190.6
Affiliates	2.0	1.3
Other	7.0	5.1
Gas Payables:		
Transportation and exchange	13.0	17.8
Storage	54.7	35.3
Accrued taxes, other	69.8	20.2
Accrued interest	30.5	30.8
Accrued payroll and employee benefits	18.9	22.3
Construction retainage	55.7	32.2
Deferred income	2.2	7.2
Other current liabilities	34.0	26.5
Total current liabilities	594.6	389.3
Long –Term Debt	2,352.8	1,847.9
Other Liabilities and Deferred Credits:		
Pension and postretirement benefits	15.3	17.2
Asset retirement obligation	16.7	16.1
Provision for other asset retirement	44.2	42.4
Other	63.5	41.4
Total other liabilities and deferred credits	139.7	117.1
Commitments and Contingencies		
Partners' Capital:		
Common units – 100.7 million units and 90.7 million units issued and outstanding as of September 30, 2008 and December 31, 2007	1,741.6	1,473.9
Class B units – 22.9 million units issued and outstanding as of September 30, 2008	692.9	-
Subordinated units – 33.1 million units issued and outstanding as of September 30, 2008 and December 31, 2007	300.1	291.7
General partner	53.1	33.2
Accumulated other comprehensive (loss) income	(3.2)	4.2
Total partners' capital	2,784.5	1,803.0
Total Liabilities and Partners' Capital	$ 5,871.6	$ 4,157.3

The accompanying notes are an integral part of these condensed consolidated financial statements.

BOARDWALK PIPELINE PARTNERS, LP

CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Millions, except per unit amounts)
(Unaudited)

	For the Three Months Ended September 30, 2008	For the Three Months Ended September 30, 2007	For the Nine Months Ended September 30, 2008	For the Nine Months Ended September 30, 2007
Operating Revenues:				
Gas transportation	$ 172.8	$ 111.6	$ 509.5	$ 379.5
Parking and lending	3.0	6.8	12.7	38.0
Gas storage	13.7	10.3	38.0	28.5
Other	2.1	6.1	19.0	27.4
Total operating revenues	191.6	134.8	579.2	473.4
Operating Costs and Expenses:				
Operation and maintenance	68.4	45.9	164.1	128.4
Administrative and general	25.8	22.1	78.3	70.0
Depreciation and amortization	33.6	20.5	91.4	60.6
Contract settlement gain	-	-	(11.2)	-
Asset impairment	-	-	1.4	14.7
Net gain on disposal of operating assets and related contracts	(36.1)	(8.8)	(50.1)	(7.2)
Taxes other than income taxes	11.1	6.5	34.0	21.7
Total operating costs and expenses	102.8	86.2	307.9	288.2
Operating income	88.8	48.6	271.3	185.2
Other Deductions (Income):				
Interest expense	9.3	14.8	46.0	46.1
Interest income	(0.7)	(5.8)	(2.1)	(16.3)
Miscellaneous other deductions (income), net	6.3	(0.5)	0.2	(0.7)
Total other deductions	14.9	8.5	44.1	29.1
Income before income taxes	73.9	40.1	227.2	156.1
Income taxes	0.3	0.1	0.8	0.5
Net income	$ 73.6	$ 40.0	$ 226.4	$ 155.6
Net income	$ 73.6	$ 40.0	$ 226.4	$ 155.6
Less general partner's interest in Net income	3.5	1.5	9.7	4.5
Limited partners' interest in Net income	$ 70.1	$ 38.5	$ 216.7	$ 151.1
Basic and diluted net income per limited partner unit:				
Common units	$ 0.47	$ 0.35	$ 1.58	$ 1.32
Class B units	$ 0.30	$ -	$ 0.30	$ -
Subordinated units	$ 0.47	$ 0.30	$ 1.58	$ 1.32
Cash distribution per unit to common and subordinated units (a)	$ 0.47	$ 0.44	$ 1.395	$ 1.285
Weighted-average number of limited partner units outstanding:				
Common units	100.7	83.2	94.6	80.8
Class B units (a)	22.9	-	22.9	-
Subordinated units	33.1	33.1	33.1	33.1

(a) Number of Class B units shown is weighted from July 1, 2008, which is the date they became eligible to participate in earnings.

The accompanying notes are an integral part of these condensed consolidated financial statements.

BOARDWALK PIPELINE PARTNERS, LP

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Millions)
(Unaudited)

	For the Nine Months Ended September 30, 2008	For the Nine Months Ended September 30, 2007
OPERATING ACTIVITIES:		
Net income	$ 226.4	$ 155.6
Adjustments to reconcile to cash provided by operations:		
Depreciation and amortization	91.4	60.6
Amortization of deferred costs	6.9	1.2
Amortization of acquired executory contracts	(0.2)	(0.9)
Asset impairment	1.4	14.7
Gain on disposal of operating assets and related contracts	(50.1)	(7.2)
Changes in operating assets and liabilities:		
Trade and other receivables	2.4	16.4
Gas receivables and storage assets	(4.2)	(2.2)
Costs recoverable from customers	0.6	4.4
Other assets	(40.7)	(14.1)
Trade and other payables	6.7	(15.3)
Other payables, affiliates	0.7	-
Gas payables	22.9	(11.1)
Accrued liabilities	14.9	11.3
Other liabilities	(3.0)	15.3
Net cash provided by operating activities	276.1	228.7
INVESTING ACTIVITIES:		
Capital expenditures	(1,905.6)	(688.2)
Proceeds from sale of operating assets, net	63.0	5.0
Proceeds from insurance reimbursements and other recoveries	4.7	1.7
Advances to affiliates, net	0.9	0.2
Purchase of short-term investments	-	(540.0)
Net cash used in investing activities	(1,837.0)	(1,221.3)
FINANCING ACTIVITIES:		
Proceeds from long-term debt, net of issuance costs	247.2	495.3
Proceeds from borrowings on revolving credit agreement	778.0	-
Repayment of borrowings on revolving credit agreement	(522.0)	-
Distributions	(186.3)	(150.5)
Proceeds from sale of common units, net of related transaction costs	243.6	287.9
Proceeds from sale of class B units	686.0	-
Capital contribution from general partner	19.2	6.0
Net cash provided by financing activities	1,265.7	638.7
Decrease in cash and cash equivalents	(295.2)	(353.9)
Cash and cash equivalents at beginning of period	317.3	399.1
Cash and cash equivalents at end of period	$ 22.1	$ 45.2

The accompanying notes are an integral part of these condensed consolidated financial statements.

BOARDWALK PIPELINE PARTNERS, LP

CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN PARTNERS' CAPITAL
(Millions)
(Unaudited)

	Common Units	Class B Units	Subordinated Units	General Partner	Accumulated Other Comp Income (Loss)	Total Partners' Capital
Balance January 1, 2007	$ 941.8	-	$ 285.5	$ 22.1	$ 23.1	$ 1,272.5
Add (deduct):						
Net income	106.6	-	44.5	4.5	-	155.6
Distributions paid	(103.6)	-	(42.5)	(4.4)	-	(150.5)
Sale of common units, net of related transaction costs (8.0 million common units)	287.9	-	-	-	-	287.9
Capital contribution from general partner	-	-	-	6.0	-	6.0
Other comprehensive loss	-	-	-	-	(12.4)	(12.4)
Balance September 30, 2007	$ 1,232.7	-	$ 287.5	$ 28.2	$ 10.7	$ 1,559.1
Balance January 1, 2008	$ 1,473.9	-	$ 291.7	$ 33.2	$ 4.2	$ 1,803.0
Add (deduct):						
Net income	155.2	$ 6.9	54.6	9.7	-	226.4
Distributions paid	(131.1)	-	(46.2)	(9.0)	-	(186.3)
Sale of common units, net of related transaction costs (10.0 million common units)	243.6	-	-	-	-	243.6
Sale of class B units (22.9 million class B units)	-	686.0	-	-	-	686.0
Capital contribution from general partner	-	-	-	19.2	-	19.2
Other comprehensive loss	-	-	-	-	(7.4)	(7.4)
Balance September 30, 2008	$ 1,741.6	$ 692.9	$ 300.1	$ 53.1	$ (3.2)	$ 2,784.5

The accompanying notes are an integral part of these condensed consolidated financial statements.

BOARDWALK PIPELINE PARTNERS, LP

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Millions)
(Unaudited)

	For the Three Months Ended September 30, 2008	For the Three Months Ended September 30, 2007	For the Nine Months Ended September 30, 2008	For the Nine Months Ended September 30, 2007
Net income	$ 73.6	$ 40.0	$ 226.4	$ 155.6
Other comprehensive (loss) income:				
Gain (loss) on cash flow hedges	21.5	(5.8)	(25.9)	(4.9)
Reclassification adjustment transferred to Net income from cash flow hedges	7.4	(1.1)	25.1	(5.5)
Pension and other postretirement benefits costs	(2.2)	(1.8)	(6.6)	(2.0)
Total comprehensive income	$ 100.3	$ 31.3	$ 219.0	$ 143.2

The accompanying notes are an integral part of these condensed consolidated financial statements.

BOARDWALK PIPELINE PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

Note 1: Basis of Presentation

Boardwalk Pipeline Partners, LP (the Partnership) is a Delaware limited partnership formed in 2005. Its business is conducted by Boardwalk Pipelines, LP (Boardwalk Pipelines) and its subsidiaries Gulf South Pipeline Company, LP (Gulf South), Texas Gas Transmission, LLC (Texas Gas) (together, the operating subsidiaries), and Gulf Crossing Pipeline Company, LLC (Gulf Crossing), which will operate a new interstate pipeline expected to be placed in service in 2009. Boardwalk Pipelines Holding Corp. (BPHC), a wholly-owned subsidiary of Loews Corporation (Loews), owns 53.3 million common units, 22.9 million class B units and 33.1 million subordinated units. Boardwalk GP, LP (Boardwalk GP), an indirect wholly-owned subsidiary of BPHC, is the Partnership's general partner and holds a 2% general partner interest in and all of the incentive distribution rights of the Partnership, further described in Note 8. The Partnership's common units are traded under the symbol "BWP" on the New York Stock Exchange.

The accompanying unaudited condensed consolidated financial statements of the Partnership were prepared pursuant to the rules and regulations of the Securities and Exchange Commission. Certain information and footnote disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States of America have been condensed or omitted pursuant to such rules and regulations. In the opinion of management, the accompanying condensed consolidated financial statements reflect all adjustments (consisting of only normal recurring accruals) necessary to present fairly the financial position as of September 30, 2008 and December 31, 2007, and the results of operations and comprehensive income for the three and nine months ended September 30, 2008 and 2007, and changes in cash flow and changes in partners' capital for the nine months ended September 30, 2008 and 2007. Reference is made to the Notes to Consolidated Financial Statements in the 2007 Annual Report on Form 10-K, which should be read in conjunction with these unaudited condensed consolidated financial statements. The accounting policies described in Note 2 to the Consolidated Financial Statements included in such Annual Report on Form 10-K are the same used in preparing the accompanying unaudited condensed consolidated financial statements.

Net income for interim periods may not necessarily be indicative of results for the full year. All intercompany items have been eliminated in consolidation.

Note 2: Gas in Storage and Gas Receivables/Payables

Gulf South and Texas Gas store gas on behalf of others. Due to the method of storage accounting elected by Gulf South, the Partnership does not reflect volumes held by Gulf South on behalf of others on its Condensed Consolidated Balance Sheets. As of September 30, 2008 and December 31, 2007, Gulf South held 37.1 trillion British thermal units (TBtu) and 52.0 TBtu of gas owned by shippers. Gulf South loaned 2.8 and 0.2 TBtu of gas to shippers as of September 30, 2008 and December 31, 2007. Consistent with the method of storage accounting elected by Texas Gas and the risk-of-loss provisions included in its tariff, Texas Gas reflects gas held on behalf of others in Gas stored underground and records an equal offsetting payable. The amount reflected in Gas Payables on the Condensed Consolidated Balance Sheets is valued at a historical cost of gas of $54.7 million and $35.3 million at September 30, 2008 and December 31, 2007.

Note 3: Derivative Financial Instruments

Subsidiaries of the Partnership use futures, swaps, and option contracts (collectively, derivatives) to hedge exposure to various risks, including natural gas commodity price risk and interest rate risk. These derivatives are reported at fair value in accordance with Statement of Financial Accounting Standards (SFAS) No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended.

Certain volumes of gas stored underground are available for sale and subject to commodity price risk. At September 30, 2008 and December 31, 2007, approximately $3.6 million and $16.3 million of gas stored underground, which the Partnership owns and carries as current Gas stored underground, was exposed to commodity price risk. The Partnership utilizes derivatives to hedge certain exposures to market price fluctuations on the anticipated operational sales of gas.

As a result of the approval by the Federal Energy Regulatory Commission (FERC) of Phase III of the Western Kentucky Storage Expansion project in the first quarter 2008, approximately 5.1 billion cubic feet (Bcf) of gas stored underground with a book value of $11.8 million became available for sale. The Partnership entered into derivatives, which were designated as cash flow hedges, to hedge the price exposure related to the expected sale of this gas. All of the gas was sold in the second and third quarters of 2008, and the related derivatives were settled, resulting in gains of $19.7 million and $34.4 million for the three and nine months ended September 30, 2008, which were reported in Net gain on disposal of operating assets and related contracts on the Condensed Consolidated Statements of Income. In the third quarter 2007, approximately 0.9 Bcf of gas related to Phase II of the Western Kentucky Storage Expansion project was sold and the related derivatives were settled, resulting in a gain of $4.4 million.

In the second quarter 2007, the Partnership entered into natural gas price swaps to hedge exposure to prices associated with the purchase of 2.1 Bcf of natural gas to be used for line pack for pipeline expansion projects. The derivatives were not designated as hedges and were marked to fair value through earnings resulting in a loss of $6.3 million and a gain of $0.9 million in Miscellaneous other income, net on the Condensed Consolidated Statements of Income for the three and nine months ended September 30, 2008, and resulting in a loss of $0.4 million and $1.1 million for the corresponding periods in 2007. All of the line pack derivatives were settled as of September 30, 2008.

In August 2007, the Partnership entered into a Treasury rate lock for a notional amount of $150.0 million of principal to hedge the risk attributable to changes in the risk-free component of forward 10-year interest rates through February 1, 2008. The Treasury rate lock was designated as a cash flow hedge in accordance with SFAS No. 133. As of December 31, 2007, the Partnership recorded a payable of $8.4 million and a corresponding amount in Accumulated other comprehensive loss for the fair value of the rate lock. On February 1, 2008, the Partnership settled the rate lock and paid the counterparty approximately $15.0 million which was deferred as a component of Accumulated other comprehensive loss. The loss will be amortized to interest expense over 10 years.

The derivatives related to the sale of natural gas and cash for fuel reimbursement generally qualify for cash flow hedge accounting under SFAS No. 133 and are designated as such. The effective component of related gains and losses resulting from changes in fair values of the derivatives contracts designated as cash flow hedges are deferred as a component of Accumulated other comprehensive loss. The deferred gains and losses are recognized in the Condensed Consolidated Statements of Income when the anticipated transactions affect earnings. In situations where continued reporting of a loss in Accumulated other comprehensive loss would result in recognition of a future loss on the combination of the derivative and the hedged transaction, SFAS No. 133 requires that the loss be immediately recognized in earnings for the amount that is not expected to be recovered. The Partnership had no losses for the three months ended September 30, 2008, and reclassified losses of $1.7 million for the nine months ended September 30, 2008, from Accumulated other comprehensive loss to earnings related to amounts that are not expected to be recovered in future periods from the combination of sales of gas stored underground and the deferred losses associated with related derivatives.

Generally, for gas sales and cash for fuel reimbursement, any gains and losses on the related derivatives would be recognized in Operating Revenues. For the sale of gas related to the Western Kentucky Storage Expansion projects, any gains and losses on the related derivatives were recognized in Net (gain) loss on disposal of operating assets and related contracts. Any gains and losses on the derivatives related to the line pack gas purchases were recognized in Miscellaneous other income, net.

The changes in fair values of the derivatives designated as cash flow hedges are expected to, and do, have a high correlation to changes in value of the anticipated transactions. Each reporting period the Partnership measures the effectiveness of the cash flow hedge contracts. To the extent the changes in the fair values of the hedge contracts do not effectively offset the changes in the estimated cash flows of the anticipated transactions, the ineffective portion of the hedge contracts is currently recognized in earnings. If the anticipated transactions are no longer deemed probable to occur, hedge accounting would be terminated and changes in the fair values of the associated derivative financial instruments would be recognized currently in earnings. Less than $0.1 million of ineffectiveness was recorded for the three and nine months ended September 30, 2008. Ineffectiveness increased Net income by $0.5 million and $0.9 million for the three and nine months ended September 30, 2007. The Partnership did not discontinue any cash flow hedges during the three and nine month periods ended September 30, 2008 and 2007.

Note 4: Fair Value

SFAS No. 157, Fair Value Measurements

In 2008, the Partnership implemented the provisions of SFAS No. 157, except for the provisions related to non-financial assets and liabilities measured at fair value on a non-recurring basis, which provisions will be applied beginning in 2009. Fair value refers to the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction in the principal market in which the reporting entity transacts based on the assumptions market participants would use when pricing the asset or liability. SFAS No. 157 establishes a fair value hierarchy that prioritizes the information used to develop those assumptions giving priority, from highest to lowest, to quoted prices in active markets for identical assets and liabilities (Level 1); observable inputs not included in Level 1, for example, quoted prices for similar assets and liabilities (Level 2); and unobservable data (Level 3), for example, a reporting entity's own internal data based on the best information available in the circumstances.

The Partnership identified its derivatives as items governed by the provisions of SFAS No. 157. The derivatives for the nine months ending September 30, 2008, were natural gas price swaps and options, which were recorded at fair value based on New York Mercantile Exchange (NYMEX) quotes for natural gas futures and options. The NYMEX quotes were deemed to be observable inputs for similar assets and liabilities and rendered Level 2 inputs for purposes of disclosure. The application of SFAS No. 157 had no effect on the Partnership's financial statements.

The fair values of derivatives existing as of September 30, 2008, were included in the following captions in the Condensed Consolidated Balance Sheets (in millions):

	Total at September 30, 2008	Quoted Prices in Active Markets for Identical Assets Level 1	Significant Other Observable Inputs Level 2	Significant Unobservable Inputs Level 3
Assets:				
Prepaid expenses and other current assets	$ 4.2	-	$ 4.2	-
Other assets	1.7	-	1.7	-
Total assets	$ 5.9	-	$ 5.9	-
Liabilities:				
Other current liabilities	$ 0.2	-	$ 0.2	-
Other non-current liabilities	0.1	-	0.1	-
Total liabilities	$ 0.3	-	$ 0.3	-

SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities

Beginning in 2008, the Partnership has the option to apply the provisions of SFAS No. 159, which allows companies to elect to measure and record certain financial assets and liabilities at fair value that would not otherwise be recorded at fair value, such as long-term debt or notes receivable. Unrealized gains and losses on items for which the fair value option was chosen would be reported in earnings. The Partnership reviewed its financial assets and liabilities in existence at January 1, 2008, as well as any financial assets and liabilities entered into during the nine month period ended September 30, 2008, and did not elect the fair value option for any applicable items. Consequently, the application of SFAS No. 159 had no effect on the Partnership's financial statements.

Note 5: Income Taxes

The Partnership is not a taxable entity for federal income tax purposes. As such, it does not directly pay federal income tax. The Partnership's taxable income or loss, which may vary substantially from the net income or loss reported in the Condensed Consolidated Statements of Income, is includable in the federal income tax returns of each partner. The aggregate difference in the basis of the Partnership's net assets for financial reporting and income tax purposes cannot be readily determined as the Partnership does not have access to the information about each partner's tax attributes. The subsidiaries of the Partnership directly incur some income-based state taxes which are presented in Income taxes on the Condensed Consolidated Statements of Income.

Note 6: Commitments and Contingencies

A. Calpine Energy Services (Calpine) Settlement

In December 2007, Gulf South and Calpine filed a stipulation and agreement in Calpine's Chapter 11 Bankruptcy proceedings to settle, for approximately $16.5 million, Gulf South's claim against Calpine related to Calpine's non-payment under a transportation agreement. The claim, which was approved in January 2008, was to be paid in the form of Calpine stock, along with other general creditors having claims in the Bankruptcy proceeding. In the fourth quarter 2007, the Partnership recognized $4.1 million of revenues related to previously reserved amounts invoiced to Calpine for transportation services previously rendered. In January 2008, the Partnership sold the entire claim to a third party and received a cash payment of approximately $15.3 million. The transfer of the claim was deemed a sale and any recourse related to the sale expired in January 2008. As a result, in the first quarter 2008, the Partnership recorded a net gain of $11.2 million related to the realization of the unrecognized portion of the claim which was reported as Contract settlement gain on the Condensed Consolidated Statements of Income. The matter is considered settled and the Partnership does not expect to receive additional amounts related to the claim.

B. Hurricane Rita Settlement

In September 2005, Hurricane Rita caused physical damage to a portion of the Partnership's assets. The related remediation work was completed in 2007. In the second quarter 2008, the Partnership received insurance proceeds of $4.7 million which were applied against a receivable for probable recoveries that was established in the third quarter 2007. The Partnership received an additional $1.0 million in the third quarter 2008 as final settlement.

C. Legal Proceedings

Napoleonville Salt Dome Matter

In December 2003, natural gas leaks were observed near two natural gas storage caverns that were leased and operated by Gulf South for natural gas storage in Napoleonville, Louisiana. Gulf South commenced remediation efforts immediately and ceased using those storage caverns. Two class action lawsuits were filed relating to this incident and were converted to individual actions. Several additional individual actions have been filed against Gulf South and other defendants by local residents and businesses. In addition, the lessor of the property has filed a claim against Gulf South in an action filed against the lessor by one of Gulf South's insurers. Most of the claims have been settled and Gulf South continues to vigorously defend each of the remaining actions, however it is not possible to predict the outcome of this litigation as the cases remain in discovery. Litigation is subject to many uncertainties, and it is possible these actions could be decided unfavorably. Gulf South has settled many of the cases filed against it and may enter into discussions in an attempt to settle the remaining cases if Gulf South believes it is appropriate to do so. For the nine-month period ended September 30, 2008, the Partnership received $4.1 million in insurance proceeds related to previously incurred litigation and remediation costs, which were recorded as a reduction to Operation and maintenance expense.

Other Legal Matters

The Partnership's subsidiaries are parties to various other legal actions arising in the normal course of business. Management believes the disposition of all known outstanding legal actions will not have a material adverse impact on the Partnership's financial condition, results of operations or cash flows.

D. Regulatory and Rate Matters

Expansion Capital Projects

The Partnership has been engaged in several pipeline expansion projects as described below:

Southeast Expansion. The pipeline and two compressor stations related to this project were placed in service during 2008. This project consists of approximately 111 miles of 42-inch pipeline originating near Harrisville, Mississippi and extending to an interconnect with Transcontinental Pipe Line Company (Transco) in Choctaw County, Alabama (Transco 85), having 1.2 Bcf of peak-day transmission capacity. The Partnership will expand the project through the addition of compression facilities to meet commitments of 1.8 Bcf of peak-day transmission capacity. The Partnership expects this additional capacity to be in service during the first quarter 2009 to coincide with the commencement of service on its Gulf Crossing project. Customers have contracted at fixed rates for all of the operational capacity (with a weighted-average term of 9.2 years, including a capacity lease agreement with Gulf Crossing discussed below). Through September 30, 2008, the Partnership spent $635.5 million related to this project.

Gulf Crossing Project. The Partnership is constructing a new interstate pipeline that begins near Sherman, Texas and will proceed to the Perryville, Louisiana area and will consist of approximately 357 miles of 42-inch pipeline having approximately 1.7 Bcf of peak-day transmission capacity with the addition of incremental compression facilities. Additionally, Gulf Crossing has entered into: (i) a capacity lease agreement for 1.1 Bcf per day of capacity on the Partnership’s Gulf South pipeline system (including capacity on the Southeast Expansion and capacity on a portion of the Partnership’s recently completed East Texas to Mississippi Expansion) to make deliveries to an interconnect with Transco 85; and (ii) a capacity lease agreement with Enogex, a third-party intrastate pipeline, which will bring gas supplies to the Partnership’s system, both of which have been approved by the FERC. Customers have contracted at fixed rates for all of the operational capacity, with a weighted average term of approximately 9.5 years. The Partnership expects the pipeline to be in service during the first quarter 2009 and the compression to be fully in service in 2010. Through September 30, 2008, the Partnership spent $1.0 billion related to this project.

Fayetteville and Greenville Laterals. The Partnership is constructing two laterals on its Texas Gas pipeline system to transport gas from the Fayetteville Shale area in Arkansas to markets directly and indirectly served by the Partnership’s existing interstate pipelines. The Fayetteville Lateral will originate in Conway County, Arkansas and proceed southeast through the Bald Knob, Arkansas area to an interconnect with the Texas Gas mainline in Coahoma County, Mississippi and consist of approximately 165 miles of 36-inch pipeline. The Greenville Lateral will originate at the Texas Gas mainline near Greenville, Mississippi and proceed east to the Kosciusko, Mississippi area and consist of approximately 95 miles of 36-inch pipeline. The Greenville Lateral will allow customers to access additional markets, primarily in the Midwest, Northeast and Southeast. The Partnership recently executed contracts for additional capacity that will require it to add compression to increase the peak-day transmission capacity to approximately 1.3 Bcf for the Fayetteville Lateral and to approximately 1.0 Bcf for the Greenville Lateral. The contracts associated with this project are at fixed rates with a weighted average term of 9.9 years. The Partnership expects the first 66 miles of the Fayetteville Lateral to be in service during the fourth quarter 2008 and the remainder of the pipeline related to the Fayetteville and Greenville Laterals to be in service during the first quarter 2009. In September 2008, the Partnership made additional filings with FERC regarding the new compression required to increase the peak-day transmission capacity, which is expected to be in service during 2010. Through September 30, 2008, the Partnership spent $449.6 million related to the Fayetteville and Greenville Laterals.

The Partnership is also engaged in the following storage expansion project:

Western Kentucky Storage Expansion Phase III. The Partnership is developing up to 8.3 Bcf of new working gas capacity at its Midland storage facility and FERC has granted the Partnership market-based rate authority for this new capacity. This expansion is supported by 10-year precedent agreements for 5.1 Bcf of storage capacity. The cost of this project will be dependent on the ultimate size of the expansion. The Partnership expects 5.4 Bcf of storage capacity to be in service during the fourth quarter 2008. Through September 30, 2008, the Partnership spent $41.0 million related to this project.

E. Environmental and Safety Matters

The operating subsidiaries are subject to federal, state, and local environmental laws and regulations in connection with the operation and remediation of various operating sites. The Partnership accrues for environmental expenses resulting from existing conditions that relate to past operations when the remediation efforts are probable and the costs can be reasonably estimated. In addition to federal and state mandated remediation requirements, the Partnership often enters into voluntary remediation programs with the agencies. The Partnership believes its accruals for environmental liabilities are adequate to accomplish remediation related to federal and state regulations. Depending on the results of on-going assessments and federal and state agency review of the data, revisions to the Partnership's estimates may be necessary based on actual costs or new circumstances.

As of September 30, 2008 and December 31, 2007, the Partnership had accrued approximately $15.4 million and $17.0 million related to assessment and/or remediation costs associated with the historical use of polychlorinated biphenyls, petroleum hydrocarbons and mercury, enhancement of groundwater protection measures and other costs. The expenditures are expected to occur over approximately the next ten years. The accrual represents management's estimate of the undiscounted future obligations based on evaluations and discussions with counsel and operating personnel and the current facts and circumstances related to these matters. As of September 30, 2008 and December 31, 2007, approximately $2.7 million was recorded in Other current liabilities and approximately $12.7 million and $14.3 million were recorded in Other Liabilities and Deferred Credits.

In March 2008, the Environmental Protection Agency (EPA) adopted regulations lowering the 8-hour ozone standard relevant to non-attainment areas. Under the regulation new non-attainment areas will be identified which may require additional emission controls for compliance at as many as 14 facilities operated by the Partnership. Compliance for this standard is anticipated to occur between 2013 and 2016. The Partnership is currently evaluating its affected facilities to determine the cost necessary to become compliant with this standard.

The Partnership considers environmental assessment, remediation costs and costs associated with compliance with environmental standards to be recoverable through base rates, as they are prudent costs incurred in the ordinary course of business and, therefore, no regulatory asset has been recorded to defer these costs. The actual costs incurred will depend on the actual amount and extent of contamination discovered, the final cleanup standards mandated by the EPA or other governmental authorities and other factors.

F. Commitments

The Partnership's future capital commitments as of September 30, 2008, for contracts already authorized are expected to approximate the following amounts (in millions):

Less than 1 year	$ 271.9
1-3 years	22.6
4-5 years	-
More than 5 years	-
Total	$ 294.5

There were no substantial changes to the Partnership's operating lease commitments as disclosed in Note 3 to the Partnership's Annual Report on Form 10-K.

Note 7: Financing

Senior Unsecured Debt

For the nine months ended September 30, 2008 and 2007, the Partnership entered into the following debt issuances (in millions, except interest rate percentage):

Date of Issuance	Issuing Subsidiary	Amount of Issuance	Purchaser Discounts and Expenses	Net Proceeds	Interest Rate	Maturity Date	Interest Payable
March 2008	Texas Gas	$ 250.0	$ 2.8	$ 247.2	5.50%	April 1, 2013	April 1 and October 1
August 2007	Gulf South	225.0	2.0	223.0	5.75%	August 15, 2012	February 15 and August 15
August 2007	Gulf South	275.0	2.7	272.3	6.30%	August 15, 2017	February 15 and August 15

The notes are redeemable, in whole or in part, at the Partnership's option at any time, at a redemption price equal to the greater of 100% of the principal amount of the notes to be redeemed or a "make whole" redemption price based on the remaining scheduled payments of principal and interest discounted to the date of redemption at a Treasury rate plus 50 basis points in the case of the Texas Gas notes, 20 basis points in the case of the Gulf South 2012 notes, or 25 basis points in the case of the Gulf South 2017 notes, plus accrued and unpaid interest, if any. Other customary covenants apply, including those concerning events of default.

As of September 30, 2008 and December 31, 2007, the weighted-average interest rate of the Partnership's long-term debt was 5.89% and 5.82%.

Revolving Credit Facility

The Partnership maintains a revolving credit facility which has aggregate lending commitments of $1.0 billion. A financial institution which has a $50.0 million commitment under the revolving credit facility filed for bankruptcy protection in the third quarter 2008 and has not funded its portion of the Partnership's borrowing requests since that time. Borrowings outstanding under the credit facility as of September 30, 2008, were $256.0 million with a weighted-average borrowing rate of 3.00%. As of September 30, 2008, the Partnership and its subsidiaries were in compliance with all covenant requirements under the credit agreement. No funds were drawn under the Partnership's revolving credit facility at December 31, 2007. Subsequent to September 30, 2008, the Partnership borrowed all of the remaining unfunded commitments under the credit facility (excluding the unfunded commitment of the bankrupt lender noted above), which increased borrowings to $958.0 million.

Capitalized Interest and Allowance for Funds Used During Construction

During the three and nine months ended September 30, 2008, the Partnership capitalized interest of $21.9 million and $45.3 million. During the three and nine months ended September 30, 2007, the Partnership capitalized interest of $8.2 million and $14.5 million. In accordance with SFAS No. 71, *Accounting for the Effect of Certain Types of Regulation*, the Partnership's Texas Gas subsidiary capitalizes allowance for funds used during construction (AFUDC), comprised of debt and equity components for certain of its operations. The Partnership capitalized AFUDC of $0.1 million and $0.2 million for the three and nine months ended September 30, 2008, and $1.3 million and $2.4 million for the three and nine months ended September 30, 2007.

Offering of Common Units

For the nine months ended September 30, 2008 and 2007, the Partnership completed the following equity offerings which funds were used to finance a portion of the Partnership's expansion projects or to repay amounts borrowed under the revolving credit facility (in millions, except the offering price):

Month of Offering	Number of Common Units	Offering Price	Underwriting Discounts and Expenses	Net Proceeds (including General Partner Contribution)	Common Units Outstanding After Offering	Common Units Held by the Public After Offering
June 2008	10.0	$ 25.30	$ 9.4	$ 248.8	100.7	47.4
March 2007	8.0	36.50	4.2	293.9	83.2	29.9

Class B Units

In June 2008, the Partnership issued and sold, pursuant to the Class B Unit Purchase Agreement (the Purchase Agreement), approximately 22.9 million of class B units representing limited partner interests (class B units) to BPHC for $30.00 per class B unit, or an aggregate purchase price of $686.0 million. The Partnership's general partner also contributed $14.0 million to the Partnership to maintain its 2% interest. The Partnership used the proceeds of $700.0 million to repay amounts borrowed under the revolving credit facility and to fund a portion of the costs of its ongoing expansion projects. The Class B units are convertible into common units by the holder on a one-for-one basis at any time after June 30, 2013.

The class B units share in quarterly distributions of available cash from operating surplus on a pari passu basis with the Partnership's common units, until each common unit and class B unit has received a quarterly distribution of $0.30. The class B units do not participate in quarterly distributions above $0.30 per unit.

The class B units began sharing in income allocations beginning on July 1, 2008, and will begin participating in distributions that will be made beginning with the fourth quarter 2008. Income of $6.9 million was allocated to the class B capital account for the three and nine months ended September 30, 2008.

The class B units have the same voting rights as if they were outstanding common units and are entitled to vote as a separate class on any matters that materially adversely affect the rights or preferences of the class B units in relation to other classes of partnership interests or as required by law. Pursuant to the Purchase Agreement, the Partnership entered into a Registration Rights Agreement with BPHC covering the common units into which the class B units will be convertible. The class B units will be convertible into common units by the holder on a one-for-one basis at any time after June 30, 2013.

Note 8: Net Income per Limited Partner Unit and Cash Distributions

The Partnership calculates net income per limited partner unit in accordance with Emerging Issues Task Force (EITF) Issue No. 03-6, *Participating Securities and the Two-Class Method under FASB Statement No. 128*. In Issue 3 of EITF No. 03-6, the EITF reached a consensus that undistributed earnings for a period should be allocated to a participating security based on the contractual participation rights of the security to share in those earnings as if all of the earnings for the period had been distributed. The Partnership's general partner holds contractual participation rights which are incentive distribution rights (IDRs) in accordance with the partnership agreement as follows:

	Total Quarterly Distribution	Marginal Percentage Interest in Distributions	
	Target Amount	Limited Partner Unitholders (1),(2)	General Partner Unitholders
Minimum Quarterly Distribution	$0.3500	98%	2%
First Target Distribution	up to $0.4025	98%	2%
Second Target Distribution	above $0.4025 up to $0.4375	85%	15%
Third Target Distribution	above $0.4375 up to $0.5250	75%	25%
Thereafter	above $0.5250	50%	50%

(1) The class B unitholders participate in distributions on a pari passu basis with the Partnership’s common units up to $0.30 per quarter, beginning with the distribution that will be made in the fourth quarter 2008. The class B units do not participate in quarterly distributions above $0.30 per unit.

(2) The partnership agreement provides that during the subordination period, the subordinated units will not receive distributions until the general partner, common and class B unitholders have received their respective minimum quarterly distribution plus any arrearages. The subordinated units are not entitled to arrearages.

The amounts reported for net income per limited partner unit on the Condensed Consolidated Statements of Income for the three and nine month periods ended September 30, 2008 and 2007, were adjusted to take into account an assumed allocation to the general partner's IDRs. Payments made on account of the IDRs are determined in relation to actual declared distributions. A reconciliation of the limited partners' interest in net income and net income available to limited partners used in computing net income per limited partner unit follows (in millions, except per unit data):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2008	2007	2008	2007
Limited partners' interest in net income	$ 70.1	$ 38.5	$ 216.7	$ 151.1
Less assumed allocation to IDRs	0.1	(0.7)	7.9	0.7
Net income available to limited partners	70.0	39.2	208.8	150.4
Less assumed allocation to class B units	6.9	-	6.9	-
Less assumed allocation to subordinated units	15.6	10.1	52.3	43.7
Net income available to common units	$ 47.5	$ 29.1	$ 149.6	$ 106.7
Weighted-average common units	100.7	83.2	94.6	80.8
Weighted-average class B units (a)	22.9	-	22.9	-
Weighted-average subordinated units	33.1	33.1	33.1	33.1
Net income per limited partner unit – common units	$ 0.47	$ 0.35	$ 1.58	$ 1.32
Net income per limited partner unit – class B units	$ 0.30	$ -	$ 0.30	$ -
Net income per limited partner unit – subordinated units	$ 0.47	$ 0.30	$ 1.58	$ 1.32

(a) Number of class B units shown is weighted from July 1, 2008.

As discussed in Note 7, the class B units were not eligible to participate in income allocations until the third quarter 2008. As a result, no income allocations were made to the class B unit equity accounts and no assumed allocations to the class B units were made pursuant to EITF No. 03-6 for purpose of computing earnings per unit prior to July 1, 2008.

In the nine month periods ended September 30, 2008 and 2007, the Partnership declared quarterly distributions per unit to eligible unitholders of record, including common and subordinated units and the 2% general partner interest and IDRs held by its general partner as follows (in millions, except distribution per unit):

Payable Date	Distribution per Unit	Amount Paid to Limited Partner Unitholders	Amount Paid to General Partner Unitholders (Including IDRs)
August 11, 2008	$ 0.470	$ 62.8	$ 3.4
May 12, 2008	0.465	57.6	2.9
February 25, 2008	0.460	56.9	2.7
August 13, 2007	0.440	51.1	1.7
May 14, 2007	0.430	50.0	1.5
February 27, 2007	0.415	45.0	1.2

In October 2008, the Partnership declared a quarterly cash distribution to unitholders of record of $0.475 per unit. The subordinated units are convertible to common units on a one-to-one basis when certain distribution requirements, as defined in the partnership agreement, have been met. These requirements will have been met coincident with payment of the quarterly distribution declared in October 2008, to be paid in the fourth quarter 2008. The subordinated units will convert following this quarterly distribution to unitholders.

Note 9: Disposition of Coal Reserves

In August 2008, the Partnership completed the sale of its investment in land and coal reserves along the Ohio River in northern Kentucky and southern Indiana for $16.5 million. These assets had no book value at the time of the sale. As a result, the Partnership recorded a gain of $16.5 million related to the sale which was reported in Net gain on disposal of operating assets and related contracts in the Condensed Consolidated Statements of Income.

Note 10: Property, Plant and Equipment

In 2008, the Partnership placed in service the remaining pipeline assets and related compression associated with the East Texas to Mississippi Expansion project from Delhi, Louisiana to Harrisville, Mississippi. Additionally, the Partnership placed in service the pipeline assets and two compressor stations related to the Southeast Expansion project. As a result, approximately $1.1 billion was transferred from Construction work in progress to Property, plant and equipment during 2008. The assets will generally be depreciated over a term of 35 years.

In the first quarter 2008, the Partnership completed a review of the non-contiguous offshore assets of its Gulf South subsidiary and provided notice to the other interest holders of its intent to discontinue any use of its portion of the available capacity of these assets. As a result, the Partnership reviewed the assets for recoverability in accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, and recorded an impairment charge of approximately $1.4 million representing the net book value of the assets.

The Partnership was developing a salt dome storage cavern near Napoleonville, Louisiana. Operational tests, which were completed in July 2007, indicated that due to geological and other anomalies that could not be corrected, the Partnership would be unable to place the cavern in service as expected. As a result, the Partnership elected to abandon that cavern and is exploring the possibility of securing a new site on which a new cavern could be developed. In accordance with the requirements of SFAS No. 144, the carrying value of the cavern and related facilities was tested for recoverability. In the second quarter 2007, the Partnership recognized an impairment charge to earnings of approximately $14.7 million, representing the carrying value of the cavern, the fair value of which was determined to be zero based on discounted expected future cash flows. The charge was presented as Asset impairment on the Condensed Consolidated Statements of Income.

Note 11: Credit Concentration

Natural gas price volatility has increased dramatically in recent years, which has materially increased credit risk related to gas loaned to customers. Gas loaned to customers refers to receivables for services provided, as well as volumes owed by customers for imbalances or gas lent by the Partnership to them, generally under parking and lending and no-notice services. As of September 30, 2008, the amount of gas loaned out by the Partnership's subsidiaries was approximately 7.6 TBtu and the amount considered an imbalance was approximately 4.2 TBtu. Assuming an average market price during September 2008 of $7.54 per million British thermal units, the market value of gas loaned out and considered an imbalance at September 30, 2008, would have been approximately $88.6 million. If any significant customer should have credit or financial problems resulting in a delay or failure to repay the gas they owe the Partnership, it could have a material adverse effect on the Partnership's financial condition, results of operations and cash flows.

Note 12: Employee Benefits

Defined Benefit Plans

Texas Gas employees hired prior to November 1, 2006, are covered under a non-contributory, defined benefit pension plan. The Texas Gas Supplemental Retirement Plan provides pension benefits for the portion of an eligible employee's pension benefit that becomes subject to compensation limitations under the Internal Revenue Code. Texas Gas provides postretirement medical benefits and life insurance to retired employees who were employed full time, hired prior to January 1, 1996, and have met certain other requirements. The Partnership uses a measurement date of December 31 for its benefits plans.

Components of net periodic benefit cost for both the retirement plans and postretirement benefits other than pensions (PBOP) for the three and nine months ended September 30, 2008 and 2007, were the following (in millions):

	Retirement Plans For the Three Months Ended September 30,		PBOP For the Three Months Ended September 30,	
	2008	2007	2008	2007
Service cost	$ 0.9	$ 0.9	$ 0.1	$ 0.1
Interest cost	1.6	1.5	0.8	0.8
Expected return on plan assets	(1.7)	(1.7)	(1.3)	(1.2)
Amortization of prior service credit	-	-	(1.9)	(1.9)
Amortization of unrecognized net loss	-	0.1	-	0.2
Settlement charge	0.1	0.4	-	-
Regulatory asset (increase) decrease	-	(0.4)	1.4	1.4
Net periodic expense	$ 0.9	$ 0.8	$ (0.9)	$ (0.6)

	Retirement Plans For the Nine Months Ended September 30,		PBOP For the Nine Months Ended September 30,	
	2008	2007	2008	2007
Service cost	$ 2.7	$ 2.8	$ 0.4	$ 0.4
Interest cost	4.8	4.8	2.4	2.5
Expected return on plan assets	(5.0)	(5.3)	(3.7)	(3.6)
Amortization of prior service credit	-	-	(5.8)	(5.8)
Amortization of unrecognized net loss	-	0.2	-	0.5
Settlement charge	0.1	4.2	-	-
Regulatory asset (increase) decrease	-	(0.4)	4.1	4.1
Net periodic expense	$ 2.6	$ 6.3	$ (2.6)	$ (1.9)

Defined Contribution Plans

Gulf South employees and Texas Gas employees hired on or after November 1, 2006, are provided retirement benefits under a defined contribution money purchase plan. The operating subsidiaries also provide 401(k) plan benefits to their employees. Costs related to the Partnership's defined contribution plans were $1.6 million and $4.7 million for the three and nine months ended September 30, 2008, and $1.2 million and $3.9 million for the three and nine months ended September 30, 2007.

Note 13: Related Parties

Loews provides a variety of corporate services to the Partnership and its subsidiaries under service agreements. Services provided by Loews include, among others, information technology, tax, risk management, internal audit and corporate development services. Loews charged $3.1 million and $10.6 million for the three and nine months ended September 30, 2008, and $2.7 million and $9.3 million for the three and nine months ended September 30, 2007, to the Partnership based on the actual time spent by Loews personnel performing these services, plus related expenses.

Distributions paid related to common and subordinated units held by BPHC and the 2% general partner interest and IDRs held by Boardwalk GP were $129.5 million and $115.4 million during the nine months ended September 30, 2008 and 2007.

Note 14: Accumulated Other Comprehensive (Loss) Income

The following table shows the components of Accumulated other comprehensive (loss) income, net of tax which is included in Partners' Capital on the Condensed Consolidated Balance Sheets (in millions):

	As of September 30, 2008	As of December 31, 2007
Loss on cash flow hedges	$ (9.8)	$ (8.9)
Deferred components of net periodic benefit cost	6.6	13.1
Total Accumulated other comprehensive (loss) income	$ (3.2)	$ 4.2

Note 15: Guarantee of Securities of Subsidiaries

The Partnership has no independent assets or operations other than its investment in its subsidiaries. The Partnership's operating subsidiaries have issued securities which have all been fully and unconditionally guaranteed by the Partnership. The Partnership does have separate partners' capital including publicly traded limited partner common units.

The Partnership's subsidiaries have no significant restrictions on their ability to pay distributions or make loans to the Partnership and had no restricted assets at September 30, 2008.

Note 16: Recently Issued Accounting Pronouncements

In March 2008, the Financial Accounting Standards Board (FASB) issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities*, which requires entities to provide enhanced disclosures about (a) how and why the entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under SFAS No. 133 and its related interpretations, and (c) how derivative instruments and related hedged items affect the entity's financial position, financial performance, and cash flows. SFAS No. 161 is effective for fiscal years and interim periods beginning after November 15, 2008. The Partnership is evaluating the effect that SFAS No. 161 will have on its financial statements.

In March 2008, the FASB approved Emerging Issues Task Force (EITF) Issue No. 07-4, *Application of the Two-Class Method under FASB Statement No. 128, Earnings per Share, to Master Limited Partnerships*, which requires that master limited partnerships use the two-class method of allocating earnings to calculate earnings per unit. EITF Issue No. 07-4 is effective for fiscal years and interim periods beginning after December 15, 2008. The Partnership is evaluating the effect that EITF Issue No. 07-4 will have on its earnings per unit and financial statements.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis of financial condition and results of operations should be read in conjunction with our accompanying interim condensed consolidated financial statements and related notes, included elsewhere in this report and prepared in accordance with accounting principles generally accepted in the United States of America and our consolidated financial statements, related notes, Management's Discussion and Analysis of Financial Condition and Results of Operations and Risk Factors included in our Annual Report on Form 10-K for the year ended December 31, 2007.

We are a Delaware limited partnership formed in 2005. Our business is conducted by Boardwalk Pipelines, LP (Boardwalk Pipelines) and its subsidiaries Gulf South Pipeline Company, LP (Gulf South), Texas Gas Transmission, LLC (Texas Gas) (together, operating subsidiaries) and Gulf Crossing Pipeline Company, LLC (Gulf Crossing), which will operate a new interstate pipeline expected to be placed in service in 2009. Boardwalk Pipelines Holding Corp. (BPHC), a wholly-owned subsidiary of Loews Corporation (Loews), owns 53.3 million of our common units, 22.9 million of our class B units and 33.1 million of our subordinated units. Boardwalk GP, LP (Boardwalk GP), an indirect, wholly-owned subsidiary of BPHC, is our general partner and holds a 2% general partner interest in and all of our incentive distribution rights. Our common units are traded under the symbol “BWP” on the New York Stock Exchange.

Results of Operations – Business Overview

We derive our revenues primarily from the interstate transportation and storage of natural gas for third parties. Transportation and storage services are provided under firm and interruptible service agreements. Transportation rates are subject to maximum tariff rates established by the Federal Energy Regulatory Commission (FERC), although discounts from the maximum allowable cost-based rates are often granted to customers due to competition in the marketplace. Our Gulf South subsidiary is authorized to charge market-based rates for its firm and interruptible transportation and storage services. Our Texas Gas subsidiary was provided authority from FERC to charge market-based rates for the storage services associated with Phase III of our Western Kentucky Storage Expansion project.

Our transportation services consist of firm transportation, where the customer pays a capacity reservation charge to reserve pipeline capacity at certain receipt and delivery points along our pipeline systems, plus a commodity and fuel charge on the volume actually transported, and interruptible transportation, where the customer pays to transport gas only when capacity is available and used. We offer firm storage services in which the customer reserves and pays for a specific amount of storage capacity, including injection and withdrawal rights, and interruptible storage and parking and lending (PAL) services where the customer receives and pays for capacity only when it is available and used. Some PAL agreements are paid for at inception of the service and revenues for these agreements are recognized as service is provided over the term of the agreement.

Our operating costs and expenses typically do not vary significantly based upon the amount of gas transported, with the exception of fuel consumed at Gulf South’s compressor stations, which is part of Operation and maintenance expenses. We charge shippers for fuel in accordance with each pipeline’s individual tariff guidelines and Gulf South’s fuel recoveries are included as part of Gas transportation revenues.

We are not in the business of buying and selling natural gas other than for system management purposes, but changes in the price of natural gas can affect the overall supply and demand of natural gas, which in turn does affect our results of operations. We deliver to a broad mix of customers including local distribution companies, municipalities, interstate and intrastate pipelines, direct industrial users, electric power generation plants, marketers and producers. In addition to serving directly connected markets, our pipeline systems have indirect market access to the northeastern, midwestern and southeastern United States through interconnections with unaffiliated pipelines.

Our business is affected by trends involving natural gas price levels and natural gas price spreads, including spreads between physical locations on our pipeline system, which affect our transportation revenues, and spreads in natural gas prices across time (for example summer to winter), which primarily affect our PAL and storage revenues. High natural gas prices in recent years have helped to drive increased production levels in producing locations such as the Bossier Sands and Barnett Shale gas producing regions in East Texas, which has resulted in additional supply being available on the west side of our system. This has resulted in widened west-to-east basis differentials which have benefited our transportation revenues. The high natural gas prices have also driven increased production in regions such as the Fayetteville Shale in Arkansas and the Caney Woodford Shale in Oklahoma, which, together with the higher production levels in East Texas, have formed the basis for several pipeline expansion projects including those being undertaken by us. Wide spreads in natural gas prices between time periods during the past two to three years, for example fall 2006 to spring 2007, were favorable for our PAL and interruptible storage services during that period. These spreads decreased substantially in 2007 and have continued to decrease for the majority of 2008, which resulted in reduced PAL and interruptible storage revenues. We cannot predict future time period spreads or basis differentials.

Results of Operations for the Three Months Ended September 30, 2008 and 2007

Our net income for the third quarter 2008 increased $33.6 million, or 84%, from the comparable period in 2007. The primary drivers for the increase were higher revenues from firm transportation services associated with our expansion projects and gains on the disposition of coal reserves and gas sales associated with our storage expansion projects. The favorable drivers were partly offset by lower PAL revenues due to unfavorable natural gas price spreads, higher fuel costs and higher depreciation and property tax expense due to an increase in our asset base from expansion.

Operating revenues increased $56.8 million, or 42%, to $191.6 million for the third quarter 2008, compared to $134.8 million for the 2007 period. Gas transportation revenues increased $37.7 million, excluding fuel, due mainly to our expansion projects. Our fuel revenues increased $19.5 million due to expansion-related throughput and an increase in the price of natural gas. Gas storage revenues increased $3.4 million related to an increase in storage capacity associated with our Western Kentucky Storage Expansion project. These increases were partially offset by a $3.8 million decrease in PAL revenues due to unfavorable natural gas price spreads.

Operating costs and expenses increased $16.6 million, or 19%, to $102.8 million for the third quarter 2008, compared to $86.2 million for the 2007 period, primarily resulting from a $20.5 million increase in fuel costs from providing service on our expansion projects and higher natural gas prices. Depreciation and other taxes, primarily comprised of property taxes, increased $17.7 million due to an increase in our asset base from expansion and administrative and general expenses increased $3.7 million primarily due to employee related expenses, various corporate services and a bad debt recovery that favorably impacted the 2007 period. The increased expenses were partly offset by a $16.5 million gain on the disposition of coal reserves and a $15.3 million gain from the sale of gas related to our Western Kentucky Storage Expansion project. The 2007 period was also favorably impacted by $4.6 million from insurance recoveries related to the 2005 hurricanes.

Total other deductions increased by $6.4 million, or 75%, to $14.9 million for the third quarter 2008, compared to $8.5 million for the 2007 period. The increase was due to $5.9 million of losses from the mark-to-market effect of derivatives associated with the purchase of line pack for our expansion projects and decreased interest income of $5.1 million due to lower average cash balances available for investment. These amounts were partly offset by a $5.5 million decrease in interest expense related to higher capitalized interest associated with our expansion projects.

Results of Operations for the Nine Months Ended September 30, 2008 and 2007

Our net income for the first nine months of 2008 increased $70.8 million, or 46%, from the comparable period in 2007. The primary drivers for the increase were higher revenues from firm transportation services associated with our expansion projects and gains on gas sales associated with our expansion projects, disposition of coal reserves and the settlement of a contract claim. The favorable drivers were partly offset by lower PAL revenues due to unfavorable natural gas price spreads and higher depreciation and property tax expense due to an increase in our asset base from expansion. The 2007 period was unfavorably impacted by a $14.7 million impairment charge.

Operating revenues for the nine months ended September 30, 2008, increased $105.8 million, or 22%, to $579.2 million, compared to $473.4 million for the nine months ended September 30, 2007. Gas transportation revenues, excluding fuel, increased $83.0 million, $76.0 million of which was related to our expansion projects and the remainder to higher interruptible services. Fuel revenues increased $38.6 million due to expansion-related throughput and higher natural gas prices. Gas storage revenues increased $9.5 million related to an increase in storage capacity associated with our Western Kentucky Storage Expansion project. These increases were partially offset by lower PAL revenues of $25.3 million due to unfavorable natural gas price spreads.

Operating costs and expenses for the nine months ended September 30, 2008, increased $19.7 million, or 7%, to $307.9 million, compared to $288.2 million for the nine months ended September 30, 2007. The primary drivers were increased depreciation and other taxes, comprised primarily of property taxes, of $43.1 million associated with an increase in our asset base due to expansion and increased fuel costs of $41.5 million from providing service on our expansion projects and higher natural gas prices. Administrative and general expenses increased $8.3 million due to increased outside services mainly due to legal and regulatory matters and various corporate services, higher property insurance from an increase in rates and asset base, an increase in information technology-related expenses from infrastructure improvements and growth and a bad debt recovery that favorably impacted 2007. These increases were offset by a $30.8 million gain on the sale of gas related to our Western Kentucky Storage Expansion project, a $16.5 million gain on the disposition of coal reserves, and an $11.2 million gain from the settlement of a contract claim. The 2007 period was unfavorably impacted by a $14.7 million impairment charge related to our Magnolia storage facility.

Total other deductions increased by $15.0 million, or 52%, to $44.1 million for the nine months ended September 30, 2008, compared to $29.1 million for the 2007 period primarily as a result of decreased interest income due to lower average cash balances available for investment.

Liquidity and Capital Resources

We are a partnership holding company and derive all of our operating cash flow from our operating subsidiaries. Our operating subsidiaries use funds from their respective operations to fund their operating activities and maintenance capital requirements, service their indebtedness and make advances or distributions to Boardwalk Pipelines. Boardwalk Pipelines uses cash provided from the operating subsidiaries and, as needed, borrowings under its revolving credit facility discussed below, to service its outstanding indebtedness and, when available, make distributions or advances to us to fund our distributions to unitholders.

Expansion Capital Expenditures

We are currently engaged in several pipeline expansion projects, described below, and expect the estimated total cost of these projects to be as follows (in millions):

	Estimated Total Cost	Cash Invested through September 30, 2008
Southeast Expansion	$ 775	$ 635.5
Gulf Crossing Project	1,800	1,002.0
Fayetteville and Greenville Laterals	1,290	449.6
Total	$ 3,865	$ 2,087.1

Based upon our current cost estimates, we expect to incur expansion project capital expenditures of approximately $0.9 billion for the remainder of 2008 and $0.9 billion in 2009 and 2010 to complete our pipeline expansion projects. The majority of those expenditures will occur during the remainder of 2008 and the first half of 2009. Our cost and timing estimates for these projects are subject to a variety of other risks and uncertainties, including obtaining regulatory approvals, adverse weather conditions, delays in obtaining key materials, shortages of qualified labor and escalating costs of labor and materials. Please refer to Item 1A, *Risk Factors*, in our 2007 Form 10-K regarding risks associated with our expansion projects and the related financing.

We have financed our expansion capital costs through equity financings, the incurrence of debt, including sales of debt by us and our subsidiaries, borrowings under our revolving credit facility and available operating cash flow in excess of our operating needs. To complete our announced projects, we anticipate we will need to issue as much as $1.0 billion in equity by issuing limited partnership units, a portion of which is expected to be issued in the fourth quarter 2008 and the remainder in the first half of 2009. Our largest shareholder, Loews, has advised us that it is willing to purchase the entire equity investment we need to the extent the public markets remain unavailable on acceptable terms. We have not committed to any transaction at this time, however, any additional investment by Loews would be subject to review and approval, as to fairness, by our independent Conflicts Committee.

The following paragraphs describe each of our pipeline expansion projects in more detail:

Southeast Expansion. The pipeline and two compressor stations related to this project were placed in service during 2008. The project consists of approximately 111 miles of 42-inch pipeline originating near Harrisville, Mississippi and extending to an interconnect with Transcontinental Pipe Line Company (Transco) in Choctaw County, Alabama (Transco 85), having 1.2 billion cubic feet (Bcf) of peak-day transmission capacity. We are expanding the project through the addition of compression facilities to meet commitments of 1.8 Bcf of peak-day transmission capacity. We expect this additional capacity to be in service during the first quarter 2009 to coincide with the commencement of service on our Gulf Crossing project. Customers have contracted at fixed rates for all of the operational capacity (with a weighted-average term of 9.2 years, including a capacity lease agreement with Gulf Crossing discussed below).

Gulf Crossing Project. We are constructing a new interstate pipeline that begins near Sherman, Texas and will proceed to the Perryville, Louisiana area and will consist of approximately 357 miles of 42-inch pipeline having approximately 1.7 Bcf of peak-day transmission capacity with the addition of incremental compression facilities. Additionally, Gulf Crossing has entered into: (i) a capacity lease agreement for 1.1 Bcf per day of capacity on our Gulf South pipeline system (including capacity on the Southeast Expansion and capacity on a portion of our recently completed East Texas to Mississippi Expansion) to make deliveries to an interconnect with Transco 85; and (ii) a capacity lease agreement with Enogex, a third-party intrastate pipeline, which will bring gas supplies to our system, both of which have been approved by the FERC. Customers have contracted at fixed rates for all of the operational capacity, with a weighted-average term of approximately 9.5 years. We expect the pipeline to be in service during the first quarter 2009 and the compression to be fully in service in 2010.

Fayetteville and Greenville Laterals. We are constructing two laterals on our Texas Gas pipeline system to transport gas from the Fayetteville Shale area in Arkansas to markets directly and indirectly served by our existing interstate pipelines. The Fayetteville Lateral will originate in Conway County, Arkansas and proceed southeast through the Bald Knob, Arkansas area to an interconnect with the Texas Gas mainline in Coahoma County, Mississippi and consist of approximately 165 miles of 36-inch pipeline. The Greenville Lateral will originate at the Texas Gas mainline near Greenville, Mississippi and proceed east to the Kosciusko, Mississippi area and consist of approximately 95 miles of 36-inch pipeline. The Greenville Lateral will allow customers to access additional markets, primarily in the Midwest, Northeast and Southeast. We recently executed contracts for additional capacity that will require us to add compression to increase the peak-day transmission capacity to approximately 1.3 Bcf for the Fayetteville Lateral and to approximately 1.0 Bcf for the Greenville Lateral. The contracts associated with this project are at fixed rates with a weighted-average term of 9.9 years. We expect the first 66 miles of the Fayetteville Lateral to be in service during the fourth quarter 2008 and the remainder of the pipeline related to the Fayetteville and Greenville Laterals to be in service during the first quarter 2009. In September 2008, we made additional filings with FERC regarding the new compression required to increase the peak-day transmission capacity, which is expected to be in service during 2010.

We are also engaged in the following storage expansion project:

Western Kentucky Storage Expansion Phase III. We are developing up to 8.3 Bcf of new working gas capacity at our Midland storage facility and FERC has granted us market-based rate authority for this new capacity. This expansion is supported by 10-year precedent agreements for 5.1 Bcf of storage capacity. The cost of this project will be dependent on the ultimate size of the expansion. We expect 5.4 Bcf of storage capacity to be in service during the fourth quarter 2008. Through September 30, 2008, we spent $41.0 million related to this project.

Maintenance Capital Expenditures

Maintenance capital expenditures for the nine months ended September 30, 2008 and 2007, were $23.9 million and $32.3 million. We expect to fund the remaining 2008 maintenance capital expenditures of approximately $34.7 million from our operating cash flows.

Distributions

For the nine months ended September 30, 2008 and 2007, we paid distributions of $186.3 million and $150.5 million. Please see Note 8 in Part 1, Item 1 of this report for further discussion.

Equity and Debt Financing

In June 2008, we issued and sold approximately 22.9 million of class B units representing limited partner interests (class B units) to BPHC for $30.00 per class B unit, or an aggregate purchase price of $686.0 million, pursuant to the Class B Unit Purchase Agreement (the Purchase Agreement). Our general partner also contributed $14.0 million to us to maintain its 2% general partner interest. Please see Note 7 in Part 1, Item 1 of this report for further discussion.

In June 2008, we completed a public offering of 10.0 million of our common units at a price of $25.30 per unit. We received proceeds of approximately $248.8 million, net of underwriting discounts and offering expenses of $9.4 million, which includes approximately $5.2 million contributed by our general partner to maintain its 2% interest.

In March 2008, we received net proceeds of approximately $247.2 million after deducting initial purchaser discounts and offering expenses of $2.8 million from the sale of $250.0 million of 5.50% senior unsecured notes of Texas Gas due April 1, 2013.

Revolving Credit Facility

We maintain a revolving credit facility which has aggregate lending commitments of $1.0 billion, under which Boardwalk Pipelines, Gulf South and Texas Gas each may borrow funds, up to applicable sub-limits. A financial institution which has a $50.0 million commitment under the revolving credit facility filed for bankruptcy protection in the third quarter 2008 and has not funded its portion of our borrowing requests since that time. Interest on amounts drawn under the credit facility is payable at a floating rate equal to an applicable spread per annum over the London Interbank Offered Rate or a base rate defined as the greater of the prime rate or the Federal funds rate plus 50 basis points. Under the terms of the agreement, each of the borrowers must maintain a minimum ratio, as of the last day of each fiscal quarter, of consolidated total debt to consolidated earnings before income taxes, depreciation and amortization (as defined in the agreement), measured for the preceding twelve months, of not more than five to one. The revolving credit facility has a maturity date of June 29, 2012.

As of September 30, 2008, we had $256.0 million of loans outstanding under the revolving credit facility of which the weighted-average interest rate on the borrowings was 3.00%. Any letters of credit previously issued by us under the facility expired in the third quarter 2008. As of September 30, 2008, we were in compliance with all covenant requirements under our credit facility.

Subsequent to September 30, 2008, we borrowed all of the remaining unfunded commitments under the credit facility (excluding the unfunded commitment of the bankrupt lender noted above), which increased borrowings to $958.0 million.

Changes in cash flow from operating activities

Net cash provided by operating activities increased $47.4 million to $276.1 million for the nine months ended September 30, 2008, compared to $228.7 million for the comparable 2007 period, primarily due to a $59.3 million increase in cash from the change in net income excluding non-cash items such as depreciation and amortization and the recognition of income previously deferred. This increase was offset by an $11.0 million decrease in cash due to the settlement of derivatives.

Changes in cash flow from investing activities

Net cash used in investing activities increased $615.7 million to $1,837.0 million for the nine months ended September 30, 2008, compared to $1,221.3 million for the comparable 2007 period, primarily due to a $1,217.4 million increase in capital expenditures related to our expansion projects. This increase was offset by a $540.0 million decrease in short term investments which occurred in the 2007 period and $58.0 million in net proceeds from asset sales mainly related to the sale of gas related to our storage expansion projects and the disposition of coal reserves.

Changes in cash flow from financing activities

Net cash provided by financing activities increased $627.0 million to $1,265.7 million for the nine months ended September 30, 2008, compared to $638.7 million for the comparable 2007 period, primarily due to a $654.9 million increase in net proceeds from the sale of common and class B units and related general partner capital contributions. The increase was offset by a $35.8 million decrease in cash from an increase in distributions to our unitholders.

Contractual Obligations

The table below is updated for significant changes in contractual cash payment obligations as of September 30, 2008, by period (in millions):

	Total	Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years
Principal payments on long-term debt (1)	$ 2,366.0	-	-	$ 481.0	$ 1,885.0
Interest on long-term debt (2)	947.4	$ 25.5	$ 234.9	235.0	452.0
Capital commitments	294.5	271.9	22.6	-	-
Pipeline capacity agreements	59.1	1.6	12.3	12.3	32.9
Total	$ 3,667.0	$ 299.0	$ 269.8	$ 728.3	$ 2,369.9

(1) This includes our senior unsecured notes, having maturity dates from 2012 to 2027 and $256.0 million of loans outstanding under our revolving credit facility, having a maturity date of June 29, 2012.

(2) Interest obligations represent interest due on our senior unsecured notes at fixed rates. Future interest obligations under our revolving credit facility are uncertain, due to the variable interest rate on fluctuating balances. Based on a 3.00% weighted-average interest rate on amounts outstanding under our revolving credit facility as of September 30, 2008, $1.9 million, $15.4 million and $11.4 million would be due under the credit facility in less than one year, 1-3 years, and 4-5 years, respectively.

The commitments related to pipeline capacity agreements are associated with the initial 10-year term for capacity on a third-party pipeline for the Southeast Expansion project. Pursuant to the settlement of the Texas Gas rate case in 2006, we are required to annually fund an amount to the Texas Gas pension plan equal to the amount of actuarially determined net periodic pension cost, including a minimum of $3.0 million. The above table does not reflect commitments we have made after September 30, 2008, relating to our expansion projects. For information on these projects, please read “Expansion Capital Expenditures” above.

Off-Balance Sheet Arrangements

At September 30, 2008, we had no guarantees of off-balance sheet debt to third parties, no debt obligations that contain provisions requiring accelerated payment of the related obligations in the event of specified levels of declines in credit ratings, and no other off-balance sheet arrangements.

Critical Accounting Policies and Estimates

Certain amounts included in or affecting our condensed consolidated financial statements and related disclosures must be estimated, requiring us to make certain assumptions with respect to values or conditions that cannot be known with certainty at the time the financial statements are prepared. These estimates and assumptions affect the amounts we report for assets and liabilities and our disclosure of contingent assets and liabilities in our financial statements. We evaluate these estimates on an ongoing basis, utilizing historical experience, consultation with third parties and other methods we consider reasonable. Nevertheless, actual results may differ significantly from our estimates. Any effects on our business, financial position or results of operations resulting from revisions to these estimates are recorded in the periods in which the facts that give rise to the revisions become known.

During the nine months ended September 30, 2008, there were no significant changes to our critical accounting policies, judgments or estimates disclosed in our Annual Report on Form 10-K for the year ended December 31, 2007.

Forward-Looking Statements

Investors are cautioned that certain statements contained in this report, as well as some statements in periodic press releases and some oral statements made by our officials and our subsidiaries during presentations about us, are “forward-looking.” Forward-looking statements include, without limitation, any statement that may project, indicate or imply future results, events, performance or achievements, and may contain the words “expect,” “intend,” “plan,” “anticipate,” “estimate,” “believe,” “will likely result,” and similar expressions. In addition, any statement made by our management concerning future financial performance (including future revenues, earnings or growth rates), ongoing business strategies or prospects, and possible actions by our partnership or its subsidiaries, are also forward-looking statements.

Forward-looking statements are based on current expectations and projections about future events and are inherently subject to a variety of risks and uncertainties, many of which are beyond our control that could cause actual results to differ materially from those anticipated or projected. These risks and uncertainties include, among others:

- We may not complete projects, including growth or expansion projects, that we have commenced or will commence, or we may complete projects on materially different terms, cost or timing than anticipated and we may not be able to achieve the intended economic or operational benefits of any such project, if completed.

- The successful completion, timing, cost, scope and future financial performance of our expansion projects could differ materially from our expectations due to availability of contractors or equipment, weather, difficulties or delays in obtaining regulatory approvals or denied applications, land owner opposition, the lack of adequate materials, labor difficulties or shortages, expansion costs that are higher than anticipated and numerous other factors beyond our control.

- We may not complete any future debt or equity financing transaction.

- The gas transmission and storage operations of our subsidiaries are subject to rate-making policies and actions by the FERC or customers that could have an adverse impact on the rates we charge and our ability to recover our income tax allowance, our full cost of operating our pipelines and a reasonable return.

- We are subject to laws and regulations relating to the environment and pipeline operations which may expose us to significant costs, liabilities and loss of revenues. Any changes in such regulations or their application could negatively affect our business, financial condition and results of operations.

- Our operations are subject to operational hazards and unforeseen interruptions for which we may not be adequately insured.

- The cost of insuring our assets may increase dramatically.

- Because of the natural decline in gas production connected to our system, our success depends on our ability to obtain access to new sources of natural gas, which is dependent on factors beyond our control. Any decrease in supplies of natural gas in our supply areas could adversely affect our business, financial condition and results of operations.

- We may not be able to maintain or replace expiring gas transportation and storage contracts at favorable rates.

- Significant changes in natural gas prices could affect supply and demand, reducing system throughput and adversely affecting our revenues.

Developments in any of these areas could cause our results to differ materially from results that have been or may be anticipated or projected. Forward-looking statements speak only as of the date of this report and we expressly disclaim any obligation or undertaking to update these statements to reflect any change in our expectations or beliefs or any change in events, conditions or circumstances on which any forward-looking statement is based.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Total long-term debt at September 30, 2008, had a carrying value of $2.4 billion and a fair value of $2.1 billion. With the exception of our revolving credit facility, our debt has been issued at fixed rates, therefore interest expense would not be impacted by changes in interest rates. A 100 basis point increase in interest rates on our fixed rate debt would result in a decrease in fair value of approximately $120.3 million at September 30, 2008. A 100 basis point decrease would result in an increase in fair value of approximately $129.8 million at September 30, 2008. The weighted-average interest rate of our long-term debt was 5.89% at September 30, 2008.

Certain volumes of our gas stored underground are available for sale and subject to commodity price risk. At September 30, 2008 and December 31, 2007, approximately $3.6 million and $16.3 million of gas stored underground, which we own and carry as current Gas stored underground, is exposed to commodity price risk. We utilize derivatives to hedge certain exposures to market price fluctuations on the anticipated operational sales of gas.

The derivatives related to the sale of natural gas and cash for fuel reimbursement generally qualify for cash flow hedge accounting under Statement of Financial Accounting Standards (SFAS) No. 133 and are designated as such. The effective component of related gains and losses resulting from changes in fair values of the derivatives contracts designated as cash flow hedges are deferred as a component of Accumulated other comprehensive loss. The deferred gains and losses are recognized in the Condensed Consolidated Statements of Income when the anticipated transactions affect earnings. Generally, for gas sales and cash for fuel reimbursement, any gains and losses on the related derivatives would be recognized in Operating Revenues.

We are exposed to credit risk relating to the risk of loss resulting from the nonperformance by a customer of its contractual obligations. Our exposure generally relates to receivables for services provided, as well as volumes owed by customers for imbalances or gas lent by us to them, generally under PAL and no-notice service. We maintain credit policies intended to minimize credit risk and actively monitor these policies. Natural gas price volatility has increased dramatically in recent years, which has materially increased credit risk related to gas loaned to customers. As of September 30, 2008, the amount of gas loaned out by our subsidiaries was approximately 7.6 trillion British thermal units (TBtu) and the amount considered an imbalance was approximately 4.2 TBtu. Assuming an average market price during September 2008 of $7.54 per million British thermal units (MMBtu), the market value of gas loaned out and considered an imbalance at September 30, 2008, would have been approximately $88.6 million. As of December 31, 2007, the amount of gas loaned out by our subsidiaries was approximately 12.7 TBtu and the amount considered an imbalance was approximately 2.5 TBtu. Assuming an average market price during December 2007 of $7.13 per MMBtu, the market value of gas loaned out at December 31, 2007, would have been approximately $108.2 million. If any significant customer of ours should have credit or financial problems resulting in a delay or failure to repay the gas they owe to us, this could have a material adverse effect on our financial condition, results of operations and cash flows.

Our cash and cash equivalents, including funds received after September 30, 2008, as a result of borrowing all of the remaining commitments under our revolving credit facility, were invested primarily in treasury funds and treasury bills. Due to the short-term nature and type of our investments, a hypothetical 10% increase in interest rates would not have a material effect on the fair market value of our portfolio. Since we have the ability to liquidate this portfolio, we do not expect our earnings or cash flows to be materially impacted by the effect of a sudden change in market interest rates on our investment portfolio.

Item 4. Controls and Procedures

Disclosure Controls and Procedures

We maintain a system of disclosure controls and procedures designed to ensure that information required to be disclosed by us in reports that we file or submit under the federal securities laws, including this report is recorded, processed, summarized and reported on a timely basis. These disclosure controls and procedures are designed to ensure that information required to be disclosed by us under the federal securities laws is accumulated and communicated to us on a timely basis to allow decisions regarding required disclosure.

Our principal executive officer (CEO) and principal financial officer (CFO) undertook an evaluation of our disclosure controls and procedures as of the end of the period covered by this report. The CEO and CFO have concluded that our controls and procedures were effective as of September 30, 2008.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during the quarter ended September 30, 2008, that have materially affected or that are reasonably likely to materially affect our internal control over financial reporting.

PART II – OTHER INFORMATION

Item 1. Legal Proceedings

For a discussion of certain of our current legal proceedings, please see Note 6 in Part 1 in Item 1 of this report.

Item 6. Exhibits

Exhibit Number	Description
*31.1	Certification of Rolf A. Gafvert, Chief Executive Officer, pursuant to Rule 13a-14(a) and Rule 15d-14(a).
*31.2	Certification of Jamie L. Buskill, Chief Financial Officer, pursuant to Rule 13a-14(a) and Rule 15d-14(a).
*32.1	Certification of Rolf A. Gafvert, Chief Executive Officer, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.2	Certification of Jamie L. Buskill, Chief Financial Officer, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Boardwalk Pipeline Partners, LP

By: Boardwalk GP, LP
its general partner

By: Boardwalk GP, LLC
its general partner

Dated: October 28, 2008

By: */s/ Jamie L. Buskill*
Jamie L. Buskill
Senior Vice President, Chief Financial Officer and Treasurer

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Section 2: EX-31.1 (EXHIBIT 31.1)

EXHIBIT 31.1

I, Rolf A. Gafvert, certify that:

1) I have reviewed this report on Form 10-Q of Boardwalk Pipeline Partners, LP;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the condensed consolidated financial statements, and other financial information included in this report, fairly present in all material respects the balance sheets, statements of income and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5) The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors :
   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Dated: October 28, 2008

/s/ Rolf A. Gafvert
Rolf A. Gafvert
President, Chief Executive Officer and Director

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Section 3: EX-31.2 (EXHIBIT 31.2)

EXHIBIT 31.2

I, Jamie L. Buskill, certify that:

1) I have reviewed this report on Form 10-Q of Boardwalk Pipeline Partners, LP;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the condensed consolidated financial statements, and other financial information included in this report, fairly present in all material respects the balance sheets, statements of income and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15 (e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5) The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors:
   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Dated: October 28, 2008

/s/ Jamie L. Buskill
Jamie L. Buskill
Senior Vice President, Chief Financial Officer and Treasurer

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Section 4: EX-32.1 (EXHIBIT 32.1)

EXHIBIT 32.1

Certification by the Chief Executive Officer
of
Boardwalk GP, LLC
pursuant to 18 U.S.C. Section 1350
(as adopted by Section 906 of the Sarbanes-Oxley Act of 2002)

Pursuant to 18 U.S.C. Section 1350, the undersigned chief executive officer of Boardwalk GP, LLC hereby certifies, to such officer's knowledge, that the quarterly report on Form 10-Q for the period ended September 30, 2008, (the "Report") of Boardwalk Pipeline Partners, LP (the "Partnership") fully complies with the requirements of Section 13(a) or 15 (d) of the Securities Exchange Act of 1934 and the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

October 28, 2008

/s/ Rolf A. Gafvert
Rolf A. Gafvert
President, Chief Executive Officer and Director
(Principal Executive Officer)

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Section 5: EX-32.2 (EXHIBIT 32.2)

EXHIBIT 32.2

Certification by the Chief Financial Officer
of
Boardwalk GP, LLC
pursuant to 18 U.S.C. Section 1350
(as adopted by Section 906 of the Sarbanes-Oxley Act of 2002)

Pursuant to 18 U.S.C. Section 1350, the undersigned chief financial officer of Boardwalk GP, LLC hereby certifies, to such officer's knowledge, that the quarterly report on Form 10-Q for the period ended September 30, 2008, (the "Report") of Boardwalk Pipeline Partners, LP (the "Partnership") fully complies with the requirements of Section 13(a) or 15 (d) of the Securities Exchange Act of 1934 and the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

October 28, 2008

/*s/ Jamie L. Buskill*
Jamie L. Buskill
Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

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Section 6: 10-Q (FORM 10-Q THIRD QUARTER 2008)

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BWP 10-K 12/31/2007

Section 1: 10-K (FORM 10-K)

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)
☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2007

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from _______________ to _______________

Commission file number: 01-32665

BOARDWALK PIPELINE PARTNERS, LP
(Exact name of registrant as specified in its charter)

DELAWARE
(State or other jurisdiction of incorporation or organization)

20-3265614
(I.R.S. Employer Identification No.)

9 Greenway Plaza, Suite 2800
Houston, Texas 77046
(866) 913-2122
(Address and Telephone Number of Registrant's Principal Executive Office)
Securities registered pursuant to Section 12(b) of the Act:

Title of each class	*Name of each exchange on which registered*
Common Units Representing Limited Partner Interests	**New York Stock Exchange**

Securities registered pursuant to Section 12(g) of the Act: **NONE**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one)
Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☒

The aggregate market value of the common units of the registrant held by non-affiliates as of June 30, 2007 was approximately $1.1 billion. As of February 15, 2008, the registrant had 90,656,122 common units outstanding.

Documents incorporated by reference. None.

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2007 FORM 10-K

BOARDWALK PIPELINE PARTNERS, LP

PART I

Item 1. Business

Introduction

We are a Delaware limited partnership formed in 2005 to own and operate the business conducted by Boardwalk Pipelines, LP (Boardwalk Pipelines) and its subsidiaries, Gulf South Pipeline Company, LP (Gulf South) and Texas Gas Transmission, LLC (Texas Gas) (together, operating subsidiaries). Boardwalk Pipelines Holding Corp. (BPHC), a wholly-owned subsidiary of Loews Corporation (Loews), owns 53.3 million of our common units and 33.1 million of our subordinated units, constituting approximately 68.0% of our equity. Boardwalk GP, LP (Boardwalk GP), an indirect, wholly-owned subsidiary of BPHC, is our general partner and holds a 2.0% general partner interest and all of our incentive distribution rights. Our common units are traded under the symbol "BWP" on the New York Stock Exchange (NYSE).

Our Business

We are engaged in the interstate transportation and storage of natural gas. We own and operate two natural gas pipeline systems which we use to transport and store natural gas for a broad mix of customers, including local distribution companies (LDCs), municipalities, interstate and intrastate pipelines, direct industrial users, electric power generation plants, marketers and producers. Our transportation and storage rates and general terms and conditions of service (tariff) are established by, and subject to review and revision by, the Federal Energy Regulatory Commission (FERC). These rates are designed based upon certain assumptions to allow us the opportunity to recover our costs and earn a reasonable return on equity, however there can be no assurance that we will recover those costs or earn a reasonable return. Our firm and interruptible storage rates for Gulf South are market-based pursuant to authority granted by the FERC.

We provide a significant portion of our pipeline transportation and storage services through firm contracts under which our customers pay monthly capacity reservation charges (which are charges owed regardless of actual pipeline or storage capacity utilization) as well as other charges based on actual utilization of the capacity. For the year ended December 31, 2007, approximately 65.0% of our revenues were derived from capacity reservation charges under firm contracts, approximately 17.0% of our revenues were derived from other charges based on actual utilization under firm contracts and approximately 18.0% of our revenues were derived from interruptible transportation, interruptible storage, parking and lending (PAL) and other services.

We are currently undertaking several significant pipeline and storage expansion projects.

Our Pipeline and Storage Systems

Our operating subsidiaries own and operate approximately 13,550 miles of pipeline, directly serving customers in eleven states and indirectly serving customers throughout the northeastern and southeastern United States through numerous interconnections with unaffiliated pipelines. In 2007, our pipeline systems transported approximately 1.3 trillion cubic feet (Tcf) of gas. Average daily throughput on our pipeline systems during 2007 was approximately 3.6 billion cubic feet (Bcf). Our natural gas storage facilities are comprised of eleven underground storage fields located in four states with aggregate working gas capacity of approximately 155.0 Bcf. We conduct all of our natural gas transportation and storage operations through our operating subsidiaries as one segment.

The principal sources of supply for our pipeline systems are regional supply hubs and market centers located in the Gulf Coast region, including offshore Louisiana, Perryville, Louisiana area, Henry Hub in Louisiana, Agua Dulce and Carthage, Texas. Carthage, Texas provides access to natural gas supplies from the Bossier Sands and Barnett Shale gas producing regions in East Texas. The Henry Hub serves as the designated delivery point for natural gas futures contracts traded on the New York Mercantile Exchange (NYMEX). We also access wellhead supplies in eastern Texas, northern and southern Louisiana and Mississippi. We also have access to imported liquefied natural gas (LNG) through the Lake Charles, Louisiana LNG terminal, to mid-continent gas production through several third-party pipeline interconnects, and to Canadian natural gas through a pipeline interconnect with Midwestern Gas Transmission Company at Whitesville, Kentucky.

Our Gulf South System

Our Gulf South pipeline system is located along the Gulf Coast in the states of Texas, Louisiana, Mississippi, Alabama and Florida. This system is composed of:

- approximately 7,700 miles of pipeline, having a peak-day delivery capacity of approximately 4.5 Bcf per day;
- 30 compressor stations having an aggregate of approximately 253,600 horsepower; and
- two natural gas storage fields located in Louisiana and Mississippi, having aggregate storage capacity of approximately 131.0 Bcf of gas, of which approximately 83.0 Bcf is designated as working gas.

The numbers shown above include 242 miles of large diameter pipeline and one compressor station from our East Texas to Mississippi expansion project. See Expansion Projects for more information regarding the East Texas to Mississippi expansion project.

The on-system markets directly served by the Gulf South system are generally located in eastern Texas, Louisiana, southern Mississippi, southern Alabama, and the Florida panhandle. These markets include LDCs and municipalities across the system, including New Orleans, Louisiana; Jackson, Mississippi; Mobile, Alabama; and Pensacola, Florida, and end-users located across the system, including the Baton Rouge to New Orleans industrial corridor and Lake Charles, Louisiana. Gulf South also has indirect access to off-system markets through numerous interconnections with other interstate and intrastate pipelines and storage facilities. These pipeline interconnections provide access to markets throughout the northeastern and southeastern United States.

Gulf South’s Bistineau, Louisiana gas storage facility has approximately 78.0 Bcf of working gas storage capacity, with a maximum injection rate of 480 million cubic feet (MMcf) per day and a maximum withdrawal rate of 870 MMcf per day. Gulf South currently sells firm and interruptible storage services at Bistineau under FERC approved market-based rates. Gulf South’s Jackson, Mississippi gas storage facility has approximately 5.0 Bcf of working gas storage capacity, with a maximum injection rate of 100 MMcf per day and a maximum withdrawal rate of 250 MMcf per day. The Jackson gas storage facility is used for operational purposes and its capacity is not offered for sale to the market.

Our Texas Gas System

Our Texas Gas pipeline system originates in Louisiana and in East Texas and runs north and east through Louisiana, Arkansas, Mississippi, Tennessee, Kentucky, Indiana, and into Ohio, with smaller diameter lines extending into Illinois. This system is composed of:

- approximately 5,850 miles of pipeline, having a peak-day delivery capacity of approximately 3.8 Bcf per day which includes deliveries to pipeline interconnects in South Louisiana;
- 31 compressor stations having an aggregate of approximately 552,000 horsepower; and
- nine natural gas storage fields located in Indiana and Kentucky, having aggregate storage capacity of approximately 180.0 Bcf of gas, of which approximately 72.0 Bcf is designated as working gas.

The numbers shown above include 9.0 Bcf of working gas capacity from Phase II of our Western Kentucky storage expansion project. See Expansion Projects for more information regarding the Western Kentucky storage expansion project.

The direct market area for Texas Gas encompasses eight states in the southern and midwestern United States and includes the Memphis, Tennessee; Louisville, Kentucky; Cincinnati and Dayton, Ohio; and Evansville and Indianapolis, Indiana metropolitan areas. Texas Gas also has indirect market access to the Northeast through interconnections with unaffiliated pipelines.

Texas Gas owns a majority of the gas in its storage fields which it uses to meet the operational balancing needs on its system, to meet the operational requirements of its firm and interruptible storage customers and the requirements of its no-notice transportation service (NNS), which allows customers to draw from storage gas during the winter season to be repaid in-kind during the following summer season. A large portion of the gas delivered by the Texas Gas system is used for heating, resulting in substantially higher daily requirements during winter months. Texas Gas also offers summer no-notice transportation service (SNS) designed primarily to meet the needs of electrical power generation facilities during the summer season.

Expansion Projects

Pipeline Expansion Projects:

East Texas to Mississippi Expansion. On June 18, 2007, the FERC granted us the authority to construct, own and operate a pipeline expansion consisting of approximately 242 miles of 42-inch pipeline from DeSoto Parish in western Louisiana to near Harrisville, Mississippi and approximately 110,000 horsepower of new compression, having approximately 1.7 Bcf of new peak-day transmission capacity. Customers have contracted at fixed rates for 1.4 Bcf per day of firm transportation capacity on a long-term basis (with a weighted average term of approximately 6.8 years) from Carthage, Texas, which represents substantially all of the normal operating capacity. The pipeline facilities from Keatchie, Louisiana in DeSoto Parish to interconnects with Texas Gas near Bosco, Louisiana, and Columbia Gulf Transmission pipeline at Delhi, Louisiana began flowing gas on December 31, 2007. The remaining pipeline facilities from Delhi, Louisiana to Harrisville, Mississippi, began flowing gas during January 2008. Currently, the three compressor units at our Carthage compressor station are operational and we are making all of our primary firm contractual deliveries into the Delhi, Louisiana area and a substantial percentage of our primary firm contractual deliveries to markets in Mississippi. We are in the process of commissioning the remaining compression facilities associated with this project, which we expect to be completed during the second quarter 2008.

Gulf Crossing Project. We are pursuing construction of a new interstate pipeline that will begin near Sherman, Texas and proceed to the Perryville, Louisiana area. The project will be owned by Gulf Crossing Pipeline Company, LLC (Gulf Crossing), our newly formed interstate pipeline subsidiary, and will consist of approximately 357 miles of 42-inch pipeline having up to approximately 1.7 Bcf of peak-day transmission capacity. Additionally, Gulf Crossing has entered into, subject to regulatory approval: (i) an operating lease for up to 1.4 Bcf per day of capacity on our Gulf South pipeline system (including capacity on the Southeast Expansion and capacity on a portion of the East Texas to Mississippi Expansion) to make deliveries to an interconnect with Transcontinental Pipe Line Company (Transco) in Choctaw County, Alabama (Transco 85); and (ii) an operating lease with Enogex, a third-party intrastate pipeline, which will bring certain gas supplies to our system. Customers have contracted at fixed rates for 1.1 Bcf per day of long-term firm transportation capacity (with a weighted average term of approximately 9.5 years). The certificate application for this project was filed with the FERC on June 19, 2007, and we expect this project to be in service by the first quarter 2009.

Southeast Expansion. On September 28, 2007, the FERC granted us the authority to construct, own and operate a pipeline expansion originating near Harrisville, Mississippi and extending to an interconnect with Transco 85. This expansion will initially consist of approximately 112 miles of 42-inch pipeline having approximately 1.2 Bcf of peak-day transmission capacity. To accommodate volumes expected to come from the Gulf Crossing leased capacity discussed above, this project will be expanded to 2.2 Bcf of peak-day transmission capacity. In addition, the FERC approved our 260 MMcf per day operating lease with Destin Pipeline Company which will provide us enhanced access to markets in Florida. Customers have contracted at fixed rates for 660 MMcf per day of firm transportation capacity on a long-term basis (with a weighted-average term of 8.7 years), in addition to the capacity leased to Gulf Crossing discussed above. Construction has commenced and we expect this project to be in service during the second quarter 2008.

Fayetteville and Greenville Laterals. We are pursuing the construction of two laterals connected to our Texas Gas pipeline system to transport gas from the Fayetteville Shale area in Arkansas to markets directly and indirectly served by our existing interstate pipelines. The Fayetteville Lateral will originate in Conway County, Arkansas and proceed southeast through the Bald Knob, Arkansas, area to an interconnect with the Texas Gas mainline in Coahoma County, Mississippi and consist of approximately 165 miles of 36-inch pipeline with an initial design of approximately 0.8 Bcf of peak-day transmission capacity. The Greenville Lateral will originate at the Texas Gas mainline near Greenville, Mississippi and proceed east to the Kosciusko, Mississippi, area consisting of approximately 95 miles of pipeline with an initial design capacity of approximately 0.8 Bcf of peak-day transmission capacity. The Greenville Lateral will allow customers to access additional markets, primarily in the Midwest, Northeast and Southeast. Customers have contracted at fixed rates for 575 MMcf per day of initial capacity, with options for additional capacity that, if exercised, could add 325 MMcf per day of capacity. The certificate application for this project was filed with the FERC on July 11, 2007. We expect the first 60 miles of the Fayetteville Lateral to be in service during the third quarter 2008 and the remainder of the Fayetteville and Greenville Laterals to be in service during the first quarter 2009.

Pipeline Expansion Project Costs and Timing. We currently estimate that the total cost of the pipeline expansion projects discussed above will be approximately $4.5 billion, of which approximately $2.0 billion was spent or committed to material that was on order as of December 31, 2007. Our total estimated cost assumes that we will receive the necessary regulatory approvals to commence construction by June 1, 2008 on Gulf Crossing and the Fayetteville and Greenville Laterals and that we will receive the regulatory approvals to operate the pipelines on certain of our projects at higher pressures, which will allow us to utilize a higher percentage of the pipeline capacity. Delays in receipt of any of these approvals will result in higher costs and additional delays in our expected in-service dates, which would also result in delays of revenues we would have received had these delays not occurred, and in certain instances will result in the payment of penalties to certain customers.

The increase in our estimated total costs and delays reflects, among other things, higher costs due to scope changes, adverse weather conditions, delays in the receipt of regulatory approvals, and the effects of the strong demand for and limited supply of qualified contractors, labor and materials and equipment which has occurred as a result of the number of large, complex pipeline construction projects being constructed in 2007 and 2008. These difficult market conditions have resulted in higher contractor costs, higher costs for labor, materials, construction equipment and other equipment and parts, as well as shortages of skilled labor. These conditions are expected to persist and it is possible that they could result in further cost increases and delays, which could have a material adverse impact on our financial condition, results of operations and cash flows.

Storage Expansion Projects:

Western Kentucky Storage Expansion Phase II. In December 2006, the FERC issued a certificate approving the Phase II storage expansion project which expanded the working gas capacity in our western Kentucky storage complex by approximately 9.0 Bcf. This project is supported by binding commitments from customers to contract on a long-term basis (with a weighted-average term of 8.3 years) for the full additional capacity at the Texas Gas maximum applicable rate. The project was placed in service in November 2007.

Western Kentucky Storage Expansion Phase III. We have signed 10-year precedent agreements for 5.1 Bcf of storage capacity for our Phase III storage project. The certificate application for this project was filed with the FERC on June 25, 2007, seeking approval to develop up to 8.3 Bcf of new storage capacity if Texas Gas is granted market-based rate authority for the new storage capacity being proposed. The cost of this project will be dependent on the ultimate size of the expansion. We expect 5.4 Bcf of storage capacity to be in service in 2008.

Magnolia Storage Facility. We were developing a salt dome storage cavern near Napoleonville, Louisiana. Operational tests, which were completed in July 2007, indicated that due to geological and other anomalies that could not be corrected, we will be unable to place the cavern in service as expected. As a result, we have elected to abandon that cavern and are exploring the possibility of securing a new site on which a new cavern could be developed.

Nature of Contracts

We contract with our customers to provide transportation services and storage services on a firm and interruptible basis. We also provide combined firm transportation and firm storage services, which we refer to as NNS and SNS. In addition, we provide interruptible PAL services.

Transportation Services. We offer transportation services on both a firm and interruptible basis. Our customers choose, based upon their particular needs, the applicable mix of services depending upon availability of pipeline capacity, price of service and the volume and timing of the customer's requirements. Firm transportation customers reserve a specific amount of pipeline capacity at specified receipt and delivery points on our system. Firm customers generally pay fees based on the quantity of capacity reserved regardless of use, plus a commodity and fuel charge paid on the volume of gas actually transported. Capacity reservation revenues derived from a firm service contract (including NNS) are generally consistent during the contract term, but can be higher in winter peak periods, especially related to NNS agreements, than off-peak periods. Firm transportation contracts generally range in term from one to ten years, although short-term firm transportation services can be offered for any term ranging from one day to one year. In providing interruptible transportation service, we agree to transport gas for a customer when capacity is available. Interruptible transportation service customers pay a commodity charge only for the volume of gas actually transported, plus a fuel charge. Interruptible transportation agreements have terms ranging from day-to-day to multiple years, with rates that change on a daily, monthly or seasonal basis.

Storage Services. We offer customers storage services on both a firm and interruptible basis. Firm storage customers reserve a specific amount of storage capacity, including injection and withdrawal rights, while interruptible customers receive storage capacity and injection and withdrawal rights when it is available. Similar to firm transportation customers, firm storage customers generally pay fees based on the quantity of capacity reserved plus an injection and withdrawal fee. Firm storage contracts typically range in term from one to ten years. Interruptible storage customers pay for the volume of gas actually stored, and applicable injection and withdrawal fees. Generally, interruptible storage agreements are for monthly terms. Unlike most FERC-regulated pipelines, including Texas Gas, Gulf South is authorized to charge market-based rates for its firm and interruptible storage services. Texas Gas filed for the ability to charge market-based rates on capacity associated with Phase III of its Western Kentucky storage expansion project.

No Notice Service and Summer No Notice Service. NNS and SNS consist of a combination of firm transportation and storage services that allow customers to withdraw gas from storage with little or no notice and require a reservation of a specified amount of storage and transportation capacity. Customers pay a reservation charge based upon the capacity reserved plus a commodity and fuel charge based on the volume of gas actually transported. NNS and SNS provide customers with additional flexibility over traditional firm transportation and storage services. Texas Gas loans stored gas to its no notice customers who are obligated to repay the gas in-kind.

Parking and Lending Service. PAL is an interruptible service offered to customers providing them the ability to park (inject) or borrow (withdraw) gas into or out of our pipeline systems at a specific location for a specific period of time. Customers pay for PAL service in advance or on a monthly basis depending on the terms of the agreement.

Customers and Markets Served

We transport natural gas for a broad mix of customers, including LDCs, municipalities, intrastate and interstate pipelines, direct industrial users, electric power generators, marketers and producers located throughout the Gulf Coast, Midwest and Northeast regions of the United States. Customers on our Gulf South system are located throughout its service area and elsewhere or are accessed through numerous interconnects on unaffiliated pipeline systems. In contrast, our Texas Gas system primarily moves gas for its customers in a northeasterly direction to serve markets directly connected to its system and also serves indirect customer markets through interconnects with other interstate pipelines.

Based upon 2007 revenues, our customer mix was comprised as follows: LDCs (32.0%), pipeline interconnects (34.0%), storage (13.0%), industrial end-users (7.0%), power plants (6.0%) and other (8.0%). We contract directly with end-use customers and with marketers, producers and other third parties who provide transportation and storage services to end users. One customer, Atmos Energy accounted for approximately 10.0% of our 2007 operating revenues.

LDCs. Most of our LDC customers use firm transportation services, including NNS. These customers operate under contracts having a weighted-average contract term of approximately four years as of December 31, 2007. We serve approximately 190 LDCs located across our pipeline systems. The demand of these customers peaks during the winter heating season.

Pipeline Interconnects (off system). Our pipeline systems serve as feeder pipelines for long-haul interstate pipelines serving markets throughout the northeastern and southeastern United States. We have numerous interconnects with third-party interstate and intrastate pipelines.

Storage. We provide storage services to a broad mix of customers including LDCs, marketers and producers. Typically, LDCs use storage under their NNS contracts to manage winter gas supplies, marketers and producers use storage to facilitate trading opportunities, and producers also use storage to ensure their ability to produce on a consistent basis.

Industrial End Users. We provide industrial facilities with a combination of firm and interruptible transportation services. Our systems are directly connected to industrial facilities in the Baton Rouge to New Orleans industrial corridor; Lake Charles, Louisiana; Mobile, Alabama; and Pensacola, Florida. We can also access the Houston Ship Channel through third-party pipelines.

Power Plants. We serve major electrical power generators in ten states. We are directly connected to several large natural gas-fired power generation facilities, some of which are also directly connected to other pipelines. The demand of the power generating customers peaks during the summer cooling season which is counter to the winter season peak demands of the LDCs. Most of our power generating customers use a combination of SNS, firm and interruptible transportation services.

Competition

We compete with numerous intrastate and interstate pipelines throughout our service territory to provide transportation and storage services for our customers. Competition is particularly strong in the Midwest and Gulf Coast states where we compete with numerous existing pipelines and several new pipeline projects that are under way, including the Rockies Express Pipeline that will transport natural gas from northern Colorado to eastern Ohio; the Heartland Gas Pipeline currently in operation in Indiana; the Southeast Header Supply System that is currently being constructed and will transport gas from Perryville, Louisiana to markets in Florida; and the proposed Mid-Continent Express Pipeline that would transport gas from Texas to Alabama. The principal elements of competition among pipelines are rates, terms of service, access to supply and flexibility and reliability of service. In addition, regulators' continuing efforts to increase competition in the natural gas industry have increased the natural gas transportation options of our traditional customers. As a result of the regulators' policies, segmentation and capacity release have created an active secondary market which increasingly competes with our pipeline services, particularly on our Texas Gas system. Our business is, in part, dependent on the volumes of natural gas consumed in the United States. Our competitors attempt to attract new supply to their pipelines including those that are currently connected to markets served by us. We compete with these entities to maintain current business levels and to serve new demand and markets. Additionally, natural gas competes with other forms of energy available to our customers, including electricity, coal, and fuel oils.

Seasonality

Our revenues are seasonal in nature and are affected by weather and natural gas price volatility. Weather impacts natural gas demand for power generation and heating purposes, which in turn influences the value of transportation and storage across our pipeline systems. Colder than normal winters or warmer than normal summers typically result in increased pipeline transportation revenues. Natural gas prices are also volatile, influencing drilling and production which can affect the value of our storage and PAL services. Peak demand for natural gas occurs during the winter months, caused by the heating load. During 2007, approximately 56.0% of our total operating revenues were recognized in the first and fourth calendar quarters.

Government Regulation

The FERC regulates pipelines under the Natural Gas Act of 1938 (NGA) and the Natural Gas Policy Act of 1978. The FERC regulates, among other things, the rates and charges for the transportation and storage of natural gas in interstate commerce, the extension, enlargement or abandonment of jurisdictional facilities, and the financial accounting of certain regulated pipeline companies. We are also regulated by the United States Department of Transportation (DOT) under the Natural Gas Pipeline Safety Act of 1968, as amended by Title I of the Pipeline Safety Act of 1979, which regulates safety requirements in the design, construction, operation and maintenance of interstate natural gas pipelines.

Where required, our operating subsidiaries hold certificates of public convenience and necessity issued by the FERC covering certain of their facilities, activities, and services. The FERC also prescribes accounting treatment for regulatory purposes. The books and records of the operating subsidiaries may be periodically audited by the FERC.

The maximum rates that may be charged by us for gas transportation and in the case of Texas Gas, for storage services, are established through the FERC cost-of-service rate-making process. Key determinants in the cost-of-service rate-making process are the costs of providing service, the allowed rate of return on capital investments, throughput assumptions, the allocation of costs and the rate design. Texas Gas is prohibited from placing new rates into effect prior to November 1, 2010, and neither of our operating subsidiaries has an obligation to file a new rate case.

Our operations are also subject to extensive federal, state, and local laws and regulations relating to protection of the environment. These laws include, for example:

(a) the Clean Air Act and analogous state laws which impose obligations related to air emissions;

(b) the Water Pollution Control Act, commonly referred to as the Clean Water Act, and analogous state laws which regulate discharge of wastewaters from our facilities into state and federal waters;

(c) the Comprehensive Environmental Response, Compensation and Liability Act, commonly referred to as CERCLA, or the Superfund law, and analogous state laws which regulate the cleanup of hazardous substances that may have been released at properties currently or previously owned or operated by us or locations to which we have sent wastes for disposal; and

(d) the Resource Conservation and Recovery Act, and analogous state laws which impose requirements for the handling and discharge of solid and hazardous waste from our facilities. Item 1A, "Risk Factors." includes further discussion regarding our environmental risk factors.

Effects of Compliance with Environmental Regulations

Note 3 in Item 8 of this Report contains information regarding environmental compliance.

Employee Relations

At December 31, 2007, we had 1,084 employees, approximately 85 of whom are covered by a collective bargaining agreement which expires in April 2011. A satisfactory relationship continues to exist between management and labor. We maintain various defined contribution plans covering substantially all our employees and various other plans, which provide regular active employees with group life, hospital, and medical benefits, as well as disability benefits. We also have a non-contributory, defined benefit pension plan which covers Texas Gas employees hired prior to November 1, 2006. Note 9 in Item 8 of this Report contains further discussion of our employee benefits.

Available Information

Our internet website is located at *www.bwpmlp.com*. We make available free of charge, through our website, our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act as soon as reasonably practicable after we electronically file such material with the Securities and Exchange Commission (SEC). These documents are also available at the SEC's website at *www.sec.gov*. Additionally, copies of these documents, excluding exhibits, may be requested at no cost, by contacting Investor Relations, Boardwalk Pipeline Partners, LP, 9 Greenway Plaza, Suite 2800, Houston, TX 77046.

We also make available free of charge within the "Governance" section of our website, and in print to any unitholder who requests, our corporate governance guidelines, the charter of our Audit Committee, and our Code of Business Conduct and Ethics. Requests for copies may be directed in writing to: Boardwalk Pipeline Partners, LP, 9 Greenway Plaza, Suite 2800, Houston, TX 77046, Attention: Corporate Secretary.

Interested parties may contact the chairpersons of any of our Board committees, our Board's independent directors as a group or our full Board in writing by mail to Boardwalk Pipeline Partners, LP, 9 Greenway Plaza, Suite 2800, Houston, TX 77046, Attention: Corporate Secretary. All such communications will be delivered to the director or directors to whom they are addressed.

Item 1A. Risk Factors

Our business faces many risks. We have described below some of the more material risks which we and our subsidiaries face. There may be additional risks that we do not yet know of or that we do not currently perceive to be material that may also impact our business or the business of our subsidiaries.

Each of the risks and uncertainties described below could lead to events or circumstances that may have a material adverse effect on our business, financial condition, results of operations and cash flows, including our ability to make distributions to our unitholders.

All of the information included in this report and any subsequent reports we may file with the SEC or make available to the public before investing in any securities issued by us should be carefully considered and evaluated.

Business Risks

We are undertaking large, complex expansion projects which involve significant risks that may adversely affect our business.

We are currently undertaking several large, complex pipeline expansion projects, as discussed above under Business – Expansion Projects, and we may also consider additional expansion projects in the future. In pursuing these projects, we have experienced significant cost overruns, including penalties to contractors, and we may experience additional cost increases in the future. We have also experienced construction delays and may experience additional delays in the future. Delays in construction have resulted in reduced transportation rates and liquidated damage payments to customers, as well as lost revenue opportunities and could, in the future result in similar losses or, in some cases, provide customers the right to terminate their transportation agreements relating to the delayed project.

These cost overruns and construction delays have resulted from a variety of factors, including the following:

- delays in obtaining regulatory approvals;
- adverse weather conditions;
- delays in obtaining key materials; and
- shortages of qualified labor and escalating costs of labor and materials resulting from the high level of construction activity in the pipeline industry.

In pursuing current or future expansion projects, we could experience additional delays or cost increases for the reasons described above or as a result of other factors. We may not be able to complete our current or future expansion projects on the terms, at the cost, or under the schedule that we anticipate, or at all. In addition, we cannot be certain that, if completed, these projects will perform in accordance with our expectations and other areas of our business may suffer as a result of the diversion of our management's attention and other resources from our other business concerns. Any of these factors could materially adversely affect our ability to realize the anticipated benefits from expansion projects which could have a material adverse effect on our business, financial condition, results of operations and cash flows. See also Item 1 – Expansion Projects.

Completion of our expansion projects will require significant amounts of debt and equity financing which may not be available to us on acceptable terms, or at all.

We plan to fund our expansion capital expenditures with proceeds from sales of our debt and equity securities and borrowings under our revolving credit facility; however, we cannot be certain that we will be able to issue our debt and equity securities on terms or in the proportions that we expect, or at all, particularly in light of the cost increases and construction delays we have experienced to date on our expansion projects, current credit market disruptions surrounding sub-prime residential mortgage concerns and the impact that those factors and other events are having and may have on the public securities markets generally and on the market for our securities in particular. Future sales of our equity securities would be dilutive to existing securityholders. A significant increase in our indebtedness, or an increase in our indebtedness that is proportionately greater than our issuances of equity, as well as the project cost increases and credit market conditions discussed above could negatively impact our credit ratings or our ability to remain in compliance with the financial covenants under our revolving credit agreement which could have a material adverse effect on our financial condition, results of operations and cash flows. If we are unable to finance our expansion projects as expected, we could be required to seek alternative financing, the terms of which may not be attractive to us, or to revise or cancel our expansion plans.

Our revolving credit agreement contains operating and financial covenants that restrict our business and financing activities.

The operating and financial covenants in our revolving credit agreement restrict our ability to finance future operations or capital needs or to expand or pursue our business activities. For example, our credit agreement limits our ability to make loans or investments, make material changes to the nature of our business, merge, consolidate or engage in asset sales, or grant liens or make negative pledges. The agreement also requires us to maintain a ratio of consolidated debt to consolidated earnings before interest, taxes, depreciation and amortization (as defined in the agreement) of no more than five to one, which limits the amount of additional indebtedness we can incur. Future financing agreements we may enter into may contain similar or more restrictive covenants.

Our ability to comply with the covenants and restrictions contained in our credit agreement may be affected by events beyond our control, including prevailing economic, financial and industry conditions. If market or other economic conditions or our financial performance deteriorate, our ability to comply with these covenants may be impaired. If we default under our credit agreement or another financing agreement, significant additional restrictions may become applicable, including a restriction on our ability to make distributions to unitholders. In addition, a default could result in a significant portion of our indebtedness becoming immediately due and payable, and our lenders could terminate their commitment to make further loans to us. In such event, we would not have, and may not be able to obtain, sufficient funds to make these accelerated payments.

Our natural gas transportation, gathering and storage operations are subject to Federal Energy Regulatory Commission's rate-making policies that could have an adverse impact on our ability to establish rates that would allow us to recover the full cost of operating our pipelines including a reasonable return.

Action by the FERC on currently pending matters as well as matters arising in the future could adversely affect our ability to establish reasonable rates, or to charge rates that would cover future increases in our costs, or even to continue to collect rates to maintain our current revenue levels that cover current costs, including a reasonable return. We cannot make assurances that we will be able to recover all of our costs through existing or future rates. An adverse determination in any future rate proceeding brought by or against any of our subsidiaries could have a material adverse effect on our business, financial condition and results of operations.

In 2005, FERC established a policy regarding the ability of a regulated entity to collect an allowance for income taxes in its cost of service. Generally, FERC has stated it will permit a pipeline that is a partnership (or other pass-through entity) to include in its cost-of-service an income tax allowance to the extent that its partners have an actual or potential income tax liability on the jurisdictional income generated by the partnership (or other pass-through entity). FERC will review pipelines' ability to include such an income tax allowance in their costs of service on a case-by-case basis, and the burden is on the pipelines to show that it had such actual or potential income tax liability. That policy has been further refined in 2006 and 2007 through a series of FERC orders and decisions issued by the United States Court of Appeals for the District of Columbia Circuit. Most recently, FERC's income tax allowance policy was upheld on all issues subject to appeal by the United States Court of Appeals for the District of Columbia Circuit in a decision issued in May 2007. In December 2007, FERC issued an order that again affirmed its income tax allowance policy and further clarified the implementation of that policy. If the FERC were to change its income tax allowance policy in the future, such changes could materially and adversely impact the rates we are permitted to charge as future rates are approved for our interstate transportation services.

In a related interstate oil pipeline proceeding, FERC noted that the tax deferral features of a publicly traded partnership may cause some investors to receive, for some indeterminate duration, cash distributions in excess of their taxable income, which FERC characterized as a "tax savings." FERC stated a concern that this creates an opportunity for those investors to earn an additional equity return funded by ratepayers. Responding to this concern, FERC adjusted the pipeline's equity rate of return downward based on the percentage by which the publicly traded partnership's cash flow exceeded taxable income assumed in the methodology for calculating the rate of return. A rehearing request is pending before FERC on this issue. If FERC establishes a policy of lowering a regulated entities' equity rate of return to compensate for what it considers to be a "tax savings," it is also likely that the level of maximum lawful rates would decrease from current levels.

If our subsidiaries were to file a rate case or if we were to be required to defend our rates, we would be required to establish pursuant to the income tax policy that the inclusion of an income tax allowance in our cost of service was just and reasonable. To establish that our income tax allowance is just and reasonable, our general partner may elect to require owners of our units to recertify their status as being subject to United States federal income taxation on the income generated by our subsidiaries or we may attempt to provide other evidence. We can provide no assurance that the evidence that we will be able to provide (including the information the general partner may require in the certification and recertification process) will be sufficient to establish that its unitholders, or its unitholders' owners, are subject to United States federal income tax liability on the income generated by our jurisdictional pipelines. If we are unable to establish that our unitholders, or our unitholders' owners, incur actual or potential income tax liability on the income generated by our jurisdictional pipelines, FERC could disallow a substantial portion of our regulated pipelines' income tax allowance. If FERC were to disallow a substantial portion of our regulated pipelines' income tax allowance, it is likely that the level of maximum lawful rates would decrease from current levels.

Our natural gas transportation and storage operations are subject to extensive regulation by the FERC in addition to the FERC rules and regulations related to the rates we can charge for our services.

The FERC's regulatory authority also extends to:

- operating terms and conditions of service;
- the types of services we may offer to our customers;
- construction of new facilities;
- creation, extension or abandonment of services or facilities;
- accounts and records; and
- relationships with certain types of affiliated companies involved in the natural gas business.

The FERC's action in any of these areas or modifications of its current regulations can adversely impact our ability to compete for business, the costs we incur in our operations, the construction of new facilities or our ability to recover the full cost of operating our pipelines. Another example is the time the FERC takes to approve the construction of new facilities, which could give our non-regulated competitors time to offer alternative projects or raise the costs of our projects to the point where they are no longer economical.

The FERC has authority to review pipeline contracts. If the FERC determines that a term of any such contract deviates in a material manner from a pipeline's tariff, the FERC typically will order the pipeline to remove the term from the contract and execute and re-file a new contract with the FERC, or alternatively, amend its tariff to include the deviating term, thereby offering it to all shippers. If the FERC audits a pipeline's contracts and finds material deviations that appear to be unduly discriminatory, the FERC could conduct a formal enforcement investigation, resulting in serious penalties and/or onerous ongoing compliance obligations.

Should we fail to comply with all applicable FERC administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines. Under the recently enacted Energy Policy Act of 2005, the FERC has civil penalty authority under NGA to impose penalties for current violations of up to $1,000,000 per day for each violation.

Finally, we cannot give any assurance regarding the future regulations under which we will operate our natural gas transportation and storage businesses, or the effect such regulation could have on our financial condition, results of operations and cash flows.

The outcome of certain FERC proceedings involving FERC policy statements is uncertain and could affect the level of return on equity that the Partnership may be able to achieve in any future rate proceeding.

In an effort to provide some guidance and to obtain further public comment on FERC's policies concerning return on equity determinations, on July 19, 2007, FERC issued its Proposed Proxy Policy Statement, *Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity*. In the Proposed Proxy Policy Statement, FERC proposes to permit inclusion of publicly traded partnerships in the proxy group analysis relating to return on equity determinations in rate proceedings, provided that the analysis be limited to actual publicly traded partnership distributions capped at the level of the pipeline's earnings and that evidence be provided in the form of multiyear analysis of past earnings demonstrating a publicly traded partnership's ability to provide stable earnings over time.

In a decision issued shortly after FERC issued its Proposed Proxy Policy Statement, the D.C. Circuit vacated FERC's orders in a proceeding involving *High Island Offshore System* and *Petal Gas Storage*. The Court determined that FERC had failed to adequately reflect risks of interstate pipeline operations both in populating the proxy group (from which a range of equity returns was determined) with entities the record indicated had lower risk, while excluding publicly traded partnerships primarily engaged in interstate pipeline operations, and in the placement of the pipeline under review in each proceeding within that range of equity returns. Although the Court accepted for the sake of argument FERC's rationale for excluding publicly traded partnerships from the proxy group (i.e., publicly traded partnership distributions may exceed earnings) it observed this proposition was "not self-evident."

The ultimate outcome of these proceedings is not certain and may result in new policies being established at FERC that would not allow the full use of publicly traded partnership distributions to unitholders in any proxy group comparisons or other negative adjustments used to determine return on equity in future rate proceedings. In addition, the FERC may adopt other policies or institute other proceedings that could adversely affect our ability to achieve a reasonable level of return on equity in any future rate proceeding.

Catastrophic losses are unpredictable.

The nature and location of our business, particularly with regard to our assets in the Gulf Coast region, may make us susceptible to catastrophic losses especially from hurricanes or named storms. Various other events can cause catastrophic losses, including windstorms, earthquakes, hail, explosions, and severe winter weather and fires. The frequency and severity of these events are inherently unpredictable. The extent of losses from catastrophes is a function of both the total amount of insured exposures in the affected areas and the severity of the events themselves. Although we carry insurance, in the event of a loss the coverage could be insufficient or there could be a material delay in the receipt of the insurance proceeds.

We are subject to laws and regulations relating to the environment which may expose us to significant costs, liabilities and loss of revenues.

The risk of substantial environmental costs and liabilities is inherent in natural gas transportation and storage. Our operations are subject to extensive federal, state and local laws and regulations relating to protection of the environment. These laws include, for example the Clean Air Act; the Water Pollution Control Act, commonly referred to as the Clean Water Act; CERCLA or the Superfund law; the Resource Conservation and Recovery Act and analogous state laws.

Such regulations impose, among other things, restrictions, liabilities and obligations in connection with the generation, handling, use, storage, transportation, treatment and disposal of hazardous substances and waste and in connection with spills, releases and emissions of various substances into the environment. Environmental regulations also require that our facilities, sites and other properties be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Existing environmental regulations could be revised or reinterpreted in the future and new laws and regulations could be adopted or become applicable to our operations or facilities. For example, the federal government and several states have recently proposed increased environmental regulation of many industrial activities, including increased regulation of air quality, water quality and solid waste management. In addition, government action to reduce greenhouse gas emissions and other government actions that may have the effect of requiring or encouraging reduced consumption or production of natural gas, could adversely impact our business, financial condition, results of operations and cash flows.

Compliance with current or future environmental regulations could require significant expenditures and the failure to comply with current or future regulations might result in the imposition of fines and penalties. The steps we may be required to take to bring certain of our facilities into compliance could be prohibitively expensive and we may be required to shut down or alter the operation of those facilities, which might cause us to incur losses. Further, current rate structures, customer contracts and prevailing market conditions might not allow us to recover the additional costs incurred to comply with new environmental requirements and we might not be able to obtain or maintain all required environmental regulatory approvals for certain projects. If there is a delay in obtaining any required environmental regulatory approvals or if we fail to obtain and comply with them, we may be required to shut down certain facilities or become subject to additional costs. The costs of complying with environmental regulation in the future could have a material adverse effect on our business, financial condition, results of operations and cash flows.

***Our operations are subject to operational hazards and unforeseen interruptions for which we may not be adequately insured*.**

There are a variety of operating risks inherent in our natural gas transportation and storage operations such as leaks, explosions and mechanical problems, all of which could cause substantial financial losses. Any of these or other similar occurrences could result in the disruption of our operations, substantial repair costs, personal injury or loss of human life, significant damage to property, environmental pollution, impairment of our operations and substantial revenue losses. The location of pipelines near populated areas, including residential areas, commercial business centers and industrial sites, could significantly increase the level of damages resulting from these risks.

We currently possess property, business interruption and general liability insurance, but proceeds from such insurance coverage may not be adequate for all liabilities or expenses incurred or revenues lost. Moreover, such insurance may not be available in the future at commercially reasonable costs and terms. Recent changes in the insurance markets have made it more difficult for us to obtain certain types of coverage. Moreover, after Hurricanes Katrina and Rita, there can be no assurance that we will be able to obtain the levels or types of insurance we would otherwise have obtained prior to these market changes, or that the insurance coverage we do obtain will not contain large deductibles or fail to cover certain hazards or all potential losses. The occurrence of any operating risks not fully covered by insurance could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Pipeline safety integrity programs and repairs may impose significant costs and liabilities on us.

The United States DOT Pipeline and Hazardous Materials Safety Administration (PHMSA) has issued a final rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate certain areas along their pipelines and take additional measures to protect pipeline segments located in what the rule refers to as high consequence areas (HCAs) where a leak or rupture could potentially do the most harm.

Operators are required to (1) perform ongoing assessments of pipeline integrity, (2) identify and characterize applicable threats to pipeline segments that could impact a HCA, (3) improve data collection, integration and analysis, (4) repair and remediate the pipeline as necessary and (5) implement preventive and mitigating actions. In compliance with the rule, we have initiated pipeline integrity testing programs that are intended to assess pipeline integrity. At this time, we cannot predict all of the effects this rule will have on us. However, the rule or an increase in public expectations for pipeline safety may require additional reporting, the replacement of some of our pipeline segments, the addition of monitoring equipment, and more frequent inspection or testing of our pipeline facilities. Any repair, remediation, preventative or mitigating actions may require significant capital and operating expenditures. Should we fail to comply with PHMSA rules and related regulations and orders, we could be subject to penalties and fines.

We are subject to strict regulations at many of our facilities regarding employee safety.

The workplaces associated with our pipelines are subject to the requirements of the Occupational Safety and Health Act (OSHA) and comparable state statutes that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that we maintain information about hazardous materials used or produced in our operations and that we provide this information to employees, state and local governmental authorities and local residents. The failure to comply with OSHA requirements or general industry standards, keep adequate records or monitor occupational exposure to regulated substances could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Increased competition could have a significant financial impact on us.

We compete primarily with other interstate and intrastate pipelines in the transportation and storage of natural gas. Competition is particularly strong in the Midwest and Gulf Coast states where we compete with numerous existing pipelines and will compete with several new pipeline projects that are under way, including the Rockies Express Pipeline that will transport natural gas from northern Colorado to eastern Ohio, the Heartland Gas Pipeline currently in operation in Indiana, the proposed Mid-Continent Express Pipeline that would transport gas from Texas to Alabama and the Southeast Header Supply System that is under construction and will transport gas from Perryville, Louisiana to markets in Florida. Natural gas also competes with other forms of energy available to our customers, including electricity, coal and fuel oils. The principle elements of competition among pipelines are rates, terms of service, access to gas supplies, flexibility and reliability. The FERC's policies promoting competition in gas markets are having the effect of increasing the gas transportation options for our traditional customer base. Increased competition could reduce the volumes of gas transported by our pipeline systems or, in cases where we do not have long-term fixed rate contracts, could force us to lower our transportation or storage rates. Competition could intensify the negative impact of factors that significantly decrease demand for natural gas in the markets served by our pipeline systems, such as competing or alternative forms of energy, a recession or other adverse economic conditions, weather, higher fuel costs and taxes or other governmental or regulatory actions that directly or indirectly increase the cost or limit the use of natural gas. Our ability to renew or replace existing contracts at rates sufficient to maintain current revenues and cash flows could be adversely affected by the activities of our competitors. We also compete against a number of intrastate pipelines which have significant regulatory advantages over us and other interstate pipelines because of the absence of FERC regulation. In view of potential rate increases, construction and service flexibility available to intrastate pipelines, we may lose customers and throughput to intrastate competitors. All of these competitive pressures could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Because of the natural decline in gas production from existing wells, our success depends on our ability to obtain access to new sources of natural gas and this is dependent on factors beyond our control. Any decrease in supplies of natural gas in our supply areas could adversely affect our business and operating results.

For the years 2003 to 2006, gas production from the Gulf Coast region, which supplies the majority of our throughput, has declined on average approximately 13.0% per year according to the Energy Information Administration. A large part of this decline was due to the effects of Hurricanes Katrina and Rita (hurricanes) in 2005. We cannot give any assurance regarding the gas production industry's ability to find new sources of domestic supply. Production from existing wells and gas supply basins connected to our pipelines will naturally decline over time, which means that our cash flows associated with the gathering or transportation of gas from these wells and basins will also decline over time. The amount of natural gas reserves underlying these wells may also be less than we anticipate, or the rate at which production from these reserves declines may be greater than we anticipate. Accordingly, to maintain or increase throughput levels on our pipelines, we must continually obtain access to new supplies of natural gas. The primary factors affecting our ability to obtain new sources of natural gas to our pipelines include: (1) the level of successful drilling activity near our pipelines, (2) our ability to compete for these supplies, (3) the successful completion of new LNG facilities near our pipelines, and (4) our gas quality requirements.

The level of drilling activity is dependent on economic and business factors beyond our control. The primary factor that impacts drilling decisions is the price of oil and natural gas. A sustained decline in natural gas prices could result in a decrease in exploration and development activities in the fields served by our pipelines, which would lead to reduced throughput levels on our pipelines. Other factors that impact production decisions include producers' capital budget limitations, the ability of producers to obtain necessary drilling and other governmental permits, the availability and cost of drilling rigs and other drilling equipment, and regulatory changes. Because of these factors, even if new natural gas reserves were discovered in areas served by our pipelines, producers may choose not to develop those reserves or may connect them to different pipelines.

Imported LNG is expected to be a significant component of future natural gas supply to the United States. Much of this increase in LNG supply is expected to be imported through new LNG facilities to be developed over the next decade. We cannot predict which, if any, of these projects will be constructed. We anticipate benefiting from some of these new projects and the additional gas supply they will bring to the Gulf Coast region. If a significant number of these new projects fail to be developed with their announced capacity, or there are significant delays in such development, or if they are built in locations where they are not connected to our systems or they do not influence sources of supply on our systems, we may not realize expected increases in future natural gas supply available for transportation through our systems.

If we are not able to obtain new supplies of natural gas to replace the natural decline in volumes from existing supply basins, or if the expected increase in natural gas supply through imported LNG is not realized, throughput on our pipelines would decline which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Capacity leaving our Lebanon, Ohio terminus is limited.

The northeastern terminus of our Texas Gas pipeline system is in Lebanon, Ohio, where it connects with other interstate natural gas pipelines delivering to East Coast and Midwest metropolitan areas and other indirect markets. Pipeline capacity into Lebanon is approximately 48.0% greater than pipeline capacity leaving that point, creating a bottleneck for supply into areas of high demand. As of December 31, 2007, approximately 13.0% of our long-term contracts with firm deliveries to Lebanon will expire or have the ability to terminate by the end of 2008. While demand for natural gas from our Lebanon, Ohio terminus and other interconnects in that region has remained strong in the past, there can be no assurance regarding continued demand for gas from the Gulf Coast region, including East Texas, in the face of other sources of natural gas for our various indirect markets, including pipelines from Canada, the anticipated completion of the Rockies Express pipeline in late 2009 or early 2010, and new LNG facilities proposed to be constructed along the East Coast.

Successful development of LNG import terminals in the eastern United States could reduce the demand for our services.

Development of new, or expansion of existing, LNG facilities on the East Coast could reduce the need for customers in the northeastern United States to transport natural gas from the Gulf Coast and other supply basins connected to our pipelines. This could reduce the amount of gas transported by our pipelines for delivery off-system to other interstate pipelines serving the Northeast. If we are not able to replace these volumes with volumes to other markets or other regions, throughput on our pipelines would decline which could have a material adverse effect on our financial condition, results of operations and cash flows.

We may not be able to maintain or replace expiring gas transportation and storage contracts at favorable rates.

Our primary exposure to market risk occurs at the time existing transportation contracts expire and are subject to renegotiation. As of December 31, 2007, approximately 25.0% of the firm contract load on our pipeline systems, excluding agreements related to the expansion projects, was due to expire on or before December 31, 2008. Upon expiration, we may not be able to extend contracts with existing customers or obtain replacement contracts at favorable rates or on a long-term basis. A key determinant of the value that customers can realize from firm transportation on a pipeline is the basis differential, which can be affected by, among other things, the availability of supply, available capacity, storage inventories, weather and general market demand in the respective areas.

The extension or replacement of existing contracts depends on a number of factors beyond our control, including:

- existing and new competition to deliver natural gas to our markets;
- the growth in demand for natural gas in our markets;
- whether the market will continue to support long-term contracts;
- the current basis differentials, or market price spreads between two points on our pipelines;
- whether our business strategy continues to be successful; and
- the effects of state regulation on customer contracting practices.

Any failure to extend or replace a significant portion of our existing contracts may have a material adverse effect on our business, financial condition, results of operations and cash flows.

We depend on certain key customers for a significant portion of our revenues. The loss of any of these key customers could result in a decline in our revenues.

We rely on a limited number of customers for a significant portion of revenues. For the year ended December 31, 2007, Atmos Energy accounted for approximately 10.0% of our total operating revenues. We may be unable to negotiate extensions or replacements of these contracts and those with other key customers on favorable terms. The loss of all or even a portion of the contracted volumes of these customers, as a result of competition, creditworthiness or otherwise, could have a material adverse effect on our financial condition, results of operations and cash flows, unless we are able to contract for comparable volumes from other customers at favorable rates.

We are exposed to credit risk relating to nonperformance by our customers.

Credit risk relates to the risk of loss resulting from the nonperformance by a customer of its contractual obligations. Our exposure generally relates to receivables for services provided, as well as volumes owed by customers for imbalances or gas lent by us to them, generally under PAL and NNS services. If any significant customer of ours should have credit or financial problems resulting in a delay or failure to repay the gas they owe us, it could have a material adverse effect on our financial condition, results of operations and cash flows. Item 7A of this Report contains more information on credit risk arising from gas loaned to customers.

If third-party pipelines and other facilities interconnected to our pipelines and facilities become unavailable to transport natural gas, our revenues could be adversely affected.

We depend upon third-party pipelines and other facilities that provide delivery options to and from our pipelines. For example, we can deliver approximately 500 MMcf per day to Texas Eastern at Kosciusko, Mississippi. If this or any other significant pipeline connection were to become unavailable for current or future volumes of natural gas due to repairs, damage to the facility, lack of capacity or any other reason, our ability to continue shipping natural gas to end markets could be restricted, thereby reducing our revenues. Any temporary or permanent interruption at any key pipeline interconnect which caused a material reduction in volumes transported on our pipelines or stored at our facilities could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Significant changes in natural gas prices could affect supply and demand, reducing system throughput and adversely affecting our revenues and available cash.

Higher natural gas prices could result in a decline in the demand for natural gas, and therefore, in the throughput on our pipelines. In addition, reduced price volatility could reduce the revenues generated by our PAL and storage services and could have a material adverse effect on our financial condition, results of operations and cash flows.

In general terms, the price of natural gas fluctuates in response to changes in supply, changes in demand, market uncertainty and a variety of additional factors that are beyond our control. These factors include:

- worldwide economic conditions;
- weather conditions and seasonal trends;
- levels of domestic production and consumer demand;
- the availability of LNG;
- a material decrease in the price of natural gas could have an adverse effect on the shippers who have contracted for capacity on our planned expansion projects;
- the availability of adequate transportation capacity;
- the price and availability of alternative fuels;
- the effect of energy conservation measures;
- the nature and extent of governmental regulation and taxation; and
- the anticipated future prices of natural gas, LNG and other commodities.

We do not own all of the land on which our pipelines and facilities are located, which could disrupt our operations.

We do not own all of the land on which our pipelines and facilities are located, and we are, therefore, subject to the risk of increased costs to maintain necessary land use. We obtain the rights to construct and operate certain of our pipelines and related facilities on land owned by third parties and governmental agencies for a specific period of time. Our loss of these rights, through our inability to renew right-of-way contracts or otherwise, or increased costs to renew such rights, could have a material adverse effect on our financial condition, results of operations and cash flows.

Mergers among our customers and/or competitors could result in lower volumes being shipped on our pipelines, thereby reducing the amount of cash we generate.

Mergers among our existing customers and/or competitors could provide strong economic incentives for the combined entities to utilize systems other than ours and we could experience difficulty in replacing lost volumes and revenues. A reduction in volumes would result not only in a reduction of revenues, but also a decline in net income and cash flows of a similar magnitude, which could reduce our ability to meet our financial obligations.

Possible terrorist activities or military actions could adversely affect our business.

The continued threat of terrorism and the impact of retaliatory military and other action by the United States and its allies might lead to increased political, economic and financial market instability and volatility in prices for natural gas, which could affect the markets for our natural gas transportation and storage services. While we are taking steps that we believe are appropriate to increase the security of our energy assets, there is no assurance that we can completely secure our assets, completely protect them against a terrorist attack or obtain adequate insurance coverage for terrorist acts at reasonable rates. These developments have subjected our operations to increased risks and could have a material adverse effect on our business. In particular, we might experience increased capital or operating costs to implement increased security.

Our general partner and its affiliates own a controlling interest in us and have conflicts of interest and limited fiduciary duties, which may permit them to favor their own interests.

At December 31, 2007, a subsidiary of Loews owned a majority of our limited partner interests and owns and controls our general partner, which controls us. Although our general partner has a fiduciary duty to manage us in a manner beneficial to us and our unitholders, the directors and officers of our general partner have a fiduciary duty to manage our general partner in a manner beneficial to Loews. Furthermore, certain directors and officers of our general partner are also directors or officers of affiliates of our general partner. Conflicts of interest may arise between Loews and its subsidiaries, including our general partner, on the one hand, and us and our unitholders, on the other hand. In resolving these conflicts, our general partner may favor its own interests and the interests of its affiliates over the interests of our unitholders. These potential conflicts include, among others, the following situations:

- Loews and its affiliates may engage in competition with us.
- Neither our partnership agreement nor any other agreement requires Loews or its affiliates (other than our general partner) to pursue a business strategy that favors us. Directors and officers of Loews and its affiliates have a fiduciary duty to make decisions in the best interest of Loews shareholders, which may be contrary to our interests.
- Our general partner is allowed to take into account the interests of parties other than us, such as Loews and its affiliates, in resolving conflicts of interest, which has the effect of limiting its fiduciary duty to our unitholders.
- Some officers of our general partner who provide services to us may devote time to affiliates of our general partner and may be compensated for services rendered to such affiliates.
- Our partnership agreement limits the liability and reduces the fiduciary duties of our general partner, while also restricting the remedies available to our unitholders for actions that, without these limitations, might constitute breaches of fiduciary duty. By purchasing common units, unitholders are deemed to have consented to some actions and conflicts of interest that might otherwise constitute a breach of fiduciary or other duties under applicable law.
- Our general partner determines the amount and timing of asset purchases and sales, borrowings, repayments of indebtedness, issuances of additional partnership securities and cash reserves, each of which can affect the amount of cash that is available for distribution to our unitholders.

- Our general partner determines the amount and timing of any capital expenditures and whether an expenditure is for maintenance capital, which reduces operating surplus, or a capital improvement expenditure, which does not. Such determination can affect the amount of cash that is distributed to our unitholders and the ability of the subordinated units to convert to common units.

- In some instances, our general partner may cause us to borrow funds in order to permit the payment of cash distributions, even if the purpose or effect of the borrowing is to make a distribution on the subordinated units, to make incentive distributions or to accelerate the expiration of the subordination period.

- Our general partner determines which costs, including allocated overhead, incurred by it and its affiliates are reimbursable by us.

- Our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered on terms that are fair and reasonable to us or entering into additional contractual arrangements with any of these entities on our behalf, and provides that reimbursement to Loews for amounts allocable to us consistent with accounting and allocation methodologies generally permitted by the FERC for rate-making purposes and past business practices is deemed fair and reasonable to us.

- Our general partner intends to limit its liability regarding our contractual obligations.

- Our general partner may exercise its rights to call and purchase (1) all of our common units if at any time it and its affiliates own more than 80.0% of the outstanding common units or (2) all of our equity securities (including common units) if it and its affiliates own more than 50.0% in the aggregate of the outstanding common units, subordinated units and any other classes of equity securities and it receives an opinion of outside legal counsel to the effect that our being a pass-through entity for tax purposes has or is reasonably likely to have a material adverse effect on the maximum applicable rates we can charge our customers.

- Our general partner controls the enforcement of obligations owed to us by it and its affiliates.

- Our general partner decides whether to retain separate counsel, accountants or others to perform services for us.

Our partnership agreement limits our general partner's fiduciary duties to unitholders and restricts the remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that reduce the standards to which our general partner would otherwise be held by state fiduciary duty law. For example, our partnership agreement:

- permits our general partner to make a number of decisions in its individual capacity, as opposed to its capacity as our general partner. This entitles our general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting us, our affiliates or any limited partner. Decisions made by our general partner in its individual capacity will be made by a majority of the owners of our general partner, and not by the board of directors of our general partner. Examples of these kinds of decisions include the exercise of its call rights, its voting rights with respect to the units it owns and its registration rights and the determination of whether to consent to any merger or consolidation of the partnership;

- provides that our general partner shall not have any liability to us or our unitholders for decisions made in its capacity as general partner so long as it acted in good faith, meaning it believed that the decisions were in the best interests of the partnership;

- generally provides that affiliate transactions and resolutions of conflicts of interest not approved by the conflicts committee of the board of directors of our general partner and not involving a vote of unitholders must be on terms no less favorable to us than those generally provided to or available from unrelated third parties or be "fair and reasonable" to us and that, in determining whether a transaction or resolution is "fair and reasonable," our general partner may consider the totality of the relationships between the parties involved, including other transactions that may be particularly advantageous or beneficial to us; and

- provides that our general partner and its officers and directors will not be liable for monetary damages to us, our limited partners or assignees for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that the general partner or those other persons acted in bad faith or engaged in fraud or willful misconduct.

We have a holding company structure in which our subsidiaries conduct our operations and own our operating assets, which may affect our ability to make distributions.

We are a partnership holding company and our operating subsidiaries conduct all of our operations and own all of our operating assets. We have no significant assets other than the ownership interests in our subsidiaries. As a result, our ability to make distributions to our unitholders depends on the performance of our subsidiaries and their ability to distribute funds to us. The ability of our subsidiaries to make distributions to us may be restricted by, among other things, the provisions of existing and future indebtedness, applicable state partnership and limited liability company laws and other laws and regulations, including FERC policies.

Tax Risks

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the Internal Revenue Service (IRS) were to treat us as a corporation or if we were to become subject to additional amounts of entity-level taxation for state tax purposes, then our cash distributions to our unitholders could be substantially reduced.

The anticipated after-tax economic benefit of an investment in the common units depends largely on our being treated as a partnership for federal income tax purposes. If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35.0%, and would likely pay additional state income tax at varying rates. Distributions to our unitholders would generally be taxed again as corporate distributions, and no income, gains, losses, deductions or credits would flow through to our unitholders. Because a tax would be imposed upon us as a corporation, our cash available for distribution to our unitholders would be substantially reduced. Thus, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to our unitholders, likely causing a substantial reduction in the value of the common units.

Current law may change, causing us to be treated as a corporation for federal income tax purposes or otherwise subjecting us to additional amounts of entity-level taxation. For example, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise or other forms of taxation. Imposition of such a tax on us would reduce the cash available for distribution to unitholders.

Our partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to a material amount of entity-level taxation for federal, state or local income tax purposes, then the minimum quarterly distribution amount and the target distribution amounts will be adjusted to reflect the impact of that law on us.

The tax treatment of publicly traded partnerships or an investment in our common units is subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

The present federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by legislative, judicial or administrative changes and differing interpretations at any time. Any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively. Members of Congress are considering substantive changes to the existing U.S. tax laws that affect certain publicly traded partnerships. Although the currently proposed legislation would not appear to affect our tax treatment as a partnership, we are unable to predict whether any of these changes, or other proposals, will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units.

If the IRS contests the federal income tax positions we take, the market for our common units may be adversely impacted, and the costs of any contest will reduce our cash distributions to our unitholders.

We have not requested any ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter affecting us. The IRS may adopt positions that differ from the positions that we take. Therefore, it may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take and even then a court may not agree with some or all of the positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade. In addition, because the costs of any contest with the IRS will be borne indirectly by our unitholders and our general partner, any such contest will result in a reduction in cash available for distribution.

Our unitholders may be required to pay taxes on their share of our income even if such unitholders do not receive any cash distributions from us.

Our unitholders will be treated as partners to whom we will allocate taxable income and who will be required to pay federal income taxes and, in some cases, state and local income taxes on their share of our taxable income, whether or not such unitholders receive cash distributions from us. Our unitholders may not receive cash distributions from us equal to such unitholders’ share of our taxable income or even equal to the actual tax liability that results from such unitholders’ share of our taxable income.

Tax gain or loss on the disposition of our common units could be different than expected.

If our unitholders sell their common units, such unitholders will recognize gain or loss equal to the difference between the amount realized and such unitholders’ tax basis in those common units. Prior distributions to our unitholders in excess of the total net taxable income our unitholders were allocated for a common unit, which decreased such unitholders’ tax basis in that common unit, will, in effect, become taxable income to such unitholders if the common unit is sold at a price greater than the tax basis in that common unit, even if the price our unitholders receive is less than their original cost. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income to our unitholders. In addition, upon a unitholders’ sale of units, such unitholder may incur a tax liability in excess of the amount of cash it receives from the sale.

Tax-exempt entities and non-U.S. persons face unique tax issues from owning our common units that may result in adverse tax consequences to them.

Investment in common units by tax-exempt entities, such as individual retirement accounts (IRAs) and non-U.S. persons, raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and could be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file United States federal tax returns and pay tax on their share of our taxable income. If you are a tax exempt entity or a non-U.S. person, you should consult your tax advisor before investing in our common units.

We will treat each purchaser of common units as having the same tax benefits without regard to the common units purchased. The IRS may challenge this treatment, which could result in a decrease in the value of the common units.

Because we cannot match transferors and transferees of common units, we will adopt depreciation and amortization positions that may not conform with all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could decrease the amount of tax benefits available to our unitholders. It also could affect the timing of these tax benefits or the amount of gain from any sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to our unitholders tax returns.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first business day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first business day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations. If the IRS were to challenge this method or new Treasury Regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A unitholder whose units are loaned to a "short seller" to cover a short sale of units may be considered as having disposed of those units. If so, the unitholder would no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and may recognize gain or loss from the disposition.

Because a unitholder whose units are loaned to a "short seller" to cover a short sale of units may be considered as having disposed of the loaned units, the unitholder may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

We have adopted certain valuation methodologies that may result in a shift of income, gain, loss and deduction between the general partner and the unitholders. The IRS may challenge this treatment, which could adversely affect the value of the common units.

When we issue additional units or engage in certain other transactions, we determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our general partner. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and the general partner, which may be unfavorable to such unitholders. Moreover, under our valuation methods, subsequent purchasers of common units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between the general partner and certain of our unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from our unitholders' sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

The sale or exchange of 50% or more of our capital and profit interests during any twelve-month period will result in the termination of our partnership for federal income tax purposes.

We will be considered terminated for federal income tax purposes if there is a sale or exchange of 50.0% or more of the total interests in our capital and profits within a twelve-month period. Our termination would, among other things, result in the closing of our taxable year which would require us to file two tax returns (and could result in our unitholders receiving two Schedules K-1) for one fiscal year, and could result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in such unitholder's taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes. We would be treated as a new partnership for tax purposes and would be required to make new tax elections and could be subject to penalties if we were unable to determine in a timely manner that a termination occurred.

Our unitholders may be subject to state and local taxes and return filing requirements as a result of investing in our common units.

In addition to federal income taxes, unitholders will likely be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property now or in the future, even if our unitholders do not reside in any of those jurisdictions. Our unitholders will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, unitholders may be subject to penalties for failure to comply with those requirements. We conduct business in eleven states. We may own property or conduct business in other states or foreign countries in the future. It is our unitholders' responsibility to file all federal, state and local tax returns.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

We and Gulf South are headquartered in approximately 103,000 square feet of leased office space located in Houston, Texas. Texas Gas has its headquarters in approximately 108,000 square feet of office space in Owensboro, Kentucky in a building that it owns. Our operating subsidiaries own their respective pipeline systems in fee. A substantial portion of these systems is constructed and maintained on property owned by others pursuant to rights-of-way, easements, permits, licenses or consents.

Item 1. "Our Business–Our Pipeline and Storage Systems," contains additional information on our material property, including our pipelines and storage facilities.

Item 3. Legal Proceedings

For a discussion of certain of our current legal proceedings, please read Note 3 in Item 8 of this Report.

Item 4. Submission of Matters to a Vote of Security Holders

None.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Market Information

As of February 15, 2008, we had 90,656,122 common units outstanding held of record by approximately 36 holders. BPHC owns 53,256,122 of our common units and all of our subordinated units. Our common units are traded on the NYSE under the symbol "BWP."

The following table sets forth, for the periods indicated, the high and low sales prices for our common units, as reported on the NYSE Composite Transactions Tape, and information regarding our quarterly distributions. The last reported sales price of our common units on the NYSE on February 15, 2008 was $29.44 per unit.

	Sales Price Range per Common Unit		**Cash Distributions per Unit (a)**
	High	Low	
Year ended December 31, 2007:			
Fourth quarter	$ 33.33	$ 29.76	$ 0.46
Third quarter	37.79	28.80	0.45
Second quarter	37.46	32.65	0.44
First quarter	39.20	30.13	0.43
Year ended December 31, 2006:			
Fourth quarter	$ 31.64	$ 25.25	$ 0.415
Third quarter	29.00	23.63	0.40
Second quarter	25.18	20.90	0.38
First quarter	22.00	17.98	0.36

(a) Represents cash distributions attributable to the quarter and declared and paid to common and subordinated unitholders within 60 days after quarter end. We also paid cash distributions to our general partner with respect to its 2.0% general partner interest and, with respect to that portion of the distribution in excess of $0.4025 per unit, its incentive distribution rights described below.

Our Cash Distribution Policy

Our cash distribution policy is consistent with the terms of our partnership agreement which requires us to distribute our "available cash," as that term is defined in our partnership agreement, to unitholders on a quarterly basis. However, there is no guarantee that unitholders will receive quarterly distributions from us. Our distribution policy may be changed at any time and is subject to certain restrictions or limitations, including, among others, our general partner's broad discretion to establish reserves which could reduce cash available for distributions, FERC regulations which place restrictions on various types of cash management programs employed by companies in the energy industry, including our operating subsidiaries, the requirements of applicable state partnership and limited liability company laws, and the requirements of our revolving credit facility which would prohibit us from making distributions to unitholders if an event of default were to occur. In addition, we may lack sufficient cash to pay distributions to unitholders due to a number of factors, including those described in Item 1A, "Risk Factors," of this Report.

Incentive Distribution Rights

Incentive distribution rights represent the right to receive an increasing percentage of quarterly distributions of available cash from operating surplus after the minimum quarterly distribution and the subsequent target distribution levels have been achieved. Our general partner currently holds all of our incentive distribution rights, but may transfer these rights separately from its general partner interest, subject to restrictions in our partnership agreement.

Assuming we do not issue any additional classes of units and our general partner maintains its 2.0% interest, if we make distributions to our unitholders from operating surplus in an amount equal to the minimum quarterly distribution for any quarter, assuming no arrearages, then we will distribute any additional available cash from operating surplus for that quarter among the unitholders and our general partner as follows:

	Total Quarterly Distribution	**Marginal Percentage Interest in Distributions**	
	Target Amount	**Common and Subordinated Unitholders**	**General Partner**
Minimum Quarterly Distribution	$0.3500	98.0%	2.0%
First Target Distribution	up to $0.4025	98.0%	2.0%
Second Target Distribution	above $0.4025 up to $0.4375	85.0%	15.0%
Third Target Distribution	above $0.4375 up to $0.5250	75.0%	25.0%
Thereafter	above $0.5250	50.0%	50.0%

Subordination Period

During the subordination period, holders of our common units will have the right to receive distributions of available cash from operating surplus in an amount equal to $0.35 per unit per quarter, which we refer to as the "minimum quarterly distribution," plus any arrearages, before any distributions of available cash from operating surplus may be made on the subordinated units. No arrearages will be paid on the subordinated units. Assuming there are no arrearages in payment of the minimum quarterly distribution, the subordination period will end, and all subordinated units will convert to common units, at such time as we have made distributions from operating surplus on the common and subordinated units at least equal to the minimum quarterly distribution for each of the immediately preceding three consecutive, non-overlapping four-quarter periods; provided also that the "adjusted operating surplus" (as defined in our partnership agreement) generated during such periods equaled or exceeded the sum of the minimum quarterly distributions on all of our units during such periods. Alternatively, assuming there are no arrearages, the subordination period will end at such time as we have made distributions from operating surplus on the common and subordinated units at least equal to 150.0% of the minimum quarterly distribution for the immediately preceding four-quarter period; provided also that the adjusted operating surplus generated during such period equaled or exceeded 150.0% of the minimum quarterly distributions on all of our units during such period. The subordination period will also end, and each subordinated unit will convert into one common unit, if unitholders remove our general partner other than for cause and no units held by our general partner and its affiliates are voted in favor of such removal. We have made distributions from operating surplus on our common and subordinated units in excess of the minimum quarterly distribution for the previous two consecutive, non-overlapping four-quarter periods preceding the date of this Report.

For information about our equity compensation, please see Part III, Item 12 – "Securities Authorized for Issuance under Equity Compensation Plans."

Common Unit Repurchases

On February 27, 2007, our general partner purchased 1,500 of our common units in the open market at a price of $36.61 per unit. These units were granted to our independent directors on March 5, 2007, as part of their director compensation. For information about our director compensation, please see Part III, Item 11 – "Director Compensation."

Item 6. Selected Financial Data

The following table presents summary historical financial and operating data for us and our predecessors, Boardwalk Pipelines and Texas Gas, as of the dates and for the periods indicated. In connection with the consummation of our initial public offering (IPO), BPHC contributed all of the equity interests in Boardwalk Pipelines to us. This contribution was accounted for as a transfer of assets between entities under common control in accordance with Statement of Financial Accounting Standards (SFAS) No. 141, *Business Combinations*. Therefore, the results of Boardwalk Pipelines prior to November 15, 2005, have been combined with our results subsequent to November 15, 2005, as our consolidated results for 2005. Boardwalk Pipelines was formed in April 2003 to acquire all of the outstanding capital stock of Texas Gas, the acquisition of which was completed on May 16, 2003 (the TG-Acquisition). Boardwalk Pipelines had no assets or operations prior to the TG-Acquisition; therefore, we refer to Texas Gas as their predecessor.

The TG-Acquisition was accounted for using the purchase method of accounting and, accordingly, the post-acquisition financial information included below reflects the allocation of the purchase price resulting from the acquisition. As a result, the financial statements of Texas Gas for the periods prior to May 16, 2003 are not directly comparable to our financial statements subsequent to that date. The consolidated financial and operating data shown below have been separated by a bold black line delineating our predecessor's financial data from ours.

The acquisition of Gulf South by Boardwalk Pipelines in December 2004 was also accounted for using the purchase method of accounting. Accordingly, the post-acquisition financial information included below reflects the purchase. As a result, our results of operations for the year ended December 31, 2004, and prior periods are not readily comparable with our results of operations for the years ended December 31, 2007, 2006 and 2005.

Prior to its converting to a limited partnership on November 15, 2005, Boardwalk Pipelines' taxable income was included in the consolidated federal income tax return of Loews and Boardwalk Pipelines recorded a charge-in-lieu of income taxes pursuant to a tax-sharing agreement with Loews. The tax-sharing agreement required Boardwalk Pipelines to remit to Loews on a quarterly basis any federal income taxes as if it were filing a separate return. Boardwalk Pipelines and its subsidiaries were also included in the state franchise tax filings of BPHC. The franchise taxes were charged to, and recorded by, Boardwalk Pipelines and its subsidiaries pursuant to the companies' tax sharing policy. Following our IPO, we no longer record certain state franchise taxes incurred by BPHC and no longer participate in a tax-sharing agreement with Loews. Our subsidiaries directly incur some income-based state taxes, which are shown as Income taxes and charge-in-lieu of income taxes on the Consolidated Statements of Income.

As used herein, EBITDA means earnings before interest, income taxes, and depreciation and amortization. This measure is not calculated or presented in accordance with accounting principles generally accepted in the United States of America (GAAP). We explain this measure below and reconcile it to its most directly comparable financial measures calculated and presented in accordance with GAAP in "**Non-GAAP Financial Measure." The financial data below should be read in conjunction with the consolidated financial statements and notes thereto included in this Report (in thousands, except Earnings per common and subordinated unit):

	Boardwalk Pipeline Partners, LP					Predecessor
	For the Year Ended December 31,				For the Period May 17, 2003 through December 31,	For the Period January 1, 2003 through May 16,
	2007	**2006**	**2005**	**2004**	**2003**	**2003**
Total operating revenues	$ 643,268	$ 607,642	$ 560,466	$ 263,621	$ 142,860	$ 113,447
Net income	227,756	197,550	100,925	48,825	22,451	34,474
Total assets	4,157,306	2,951,299	2,465,491	2,472,140	1,238,627	N/A
Long-term debt	1,847,914	1,350,920	1,101,290	1,106,135	548,115	N/A
Earnings per common and subordinated unit	$ 1.87	$ 1.85	*	N/A	N/A	N/A
EBITDA**	$ 349,839	$ 331,468	$ 289,002	$ 144,489	$ 77,241	$ 78,380

* Our net income was $35,992, or $0.35 per common and subordinated unit, for the period from November 15, 2005, the closing date of our IPO, through December 31, 2005.

****Non-GAAP Financial Measure**

EBITDA is used as a supplemental financial measure by management and by external users of our financial statements, such as investors, commercial banks, research analysts and rating agencies, to assess:

- our financial performance without regard to financing methods, capital structure or historical cost basis;
- our ability to generate cash sufficient to pay interest on our indebtedness and to make distributions to our partners;
- our operating performance and return on invested capital as compared to those of other companies in the natural gas transportation and storage business, without regard to financing methods and capital structure; and
- the viability of acquisitions and capital expenditure projects.

EBITDA should not be considered an alternative to, or more meaningful than, net income, operating income, cash flow from operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP, or as an indicator of our operating performance or liquidity. Certain items excluded from EBITDA are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure, as well as historic costs of depreciable assets. We have included information concerning EBITDA because EBITDA provides additional information as to our ability to meet our fixed charges and is presented solely as a supplemental measure. However, viewing EBITDA as an indicator of our ability to make cash distributions on our common units should be done with caution, as we might be required to conserve funds or to allocate funds to business or legal purposes other than making distributions. EBITDA is not necessarily comparable to a similarly titled measure of another company.

The following table presents a reconciliation of EBITDA to the most directly comparable GAAP financial measures, on a historical basis, as applicable, for each of the periods presented below (in thousands):

	Boardwalk Pipeline Partners, LP					Predecessor
	For the Year Ended December 31,				For the Period May 17, 2003 through December 31,	For the Period January 1, 2003 through May 16,
	2007	2006	2005	2004	2003	2003
Net income	$ 227,756	$ 197,550	$ 100,925	$ 48,825	$ 22,451	$ 34,474
Income taxes and charge-in-lieu of income taxes	769	253	49,494	32,333	15,104	22,387
Elimination of cumulative deferred taxes	-	-	10,102	-	-	-
Depreciation and amortization	81,824	75,771	72,078	33,977	20,544	16,092
Interest expense	61,023	62,123	60,067	30,081	19,368	7,392
Interest income	(21,489)	(4,202)	(1,478)	(352)	(205)	-
Interest income from affiliates, net	(44)	(27)	(2,186)	(375)	(21)	(1,965)
EBITDA	$ 349,839	$ 331,468	$ 289,002	$ 144,489	$ 77,241	$ 78,380

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis of financial condition and results of operations should be read in conjunction with our consolidated financial statements and the related notes thereto, included in Item 8, and with Item 1A, "Risk Factors."

Overview

We are a Delaware limited partnership formed to own and operate the business conducted by our operating subsidiaries, including the interstate transportation and storage of natural gas. We own and operate pipeline systems in the Gulf Coast states of Texas, Louisiana, Mississippi, Alabama, and Florida and which extend northeasterly through Arkansas to the Midwestern states of Tennessee, Kentucky, Illinois, Indiana, and Ohio.

Our transportation services consist of firm transportation, whereby the customer pays a capacity reservation charge to reserve pipeline capacity at certain receipt and delivery points along our pipeline systems, plus a commodity and fuel charge on the volume actually transported, and interruptible transportation, whereby the customer pays to transport gas only when capacity is available and used. We offer firm storage services in which the customer reserves and pays for a specific amount of storage capacity, including injection and withdrawal rights, and interruptible storage and PAL services where the customer receives and pays for capacity only when it is available and used. Some PAL agreements are paid for at inception of the service and revenues for these agreements are recognized as service is provided over the term of the agreement. For the year ended December 31, 2007, the percentage of our Total operating revenues associated with firm contracts was approximately 81.7%.

We are not in the business of buying and selling natural gas other than for system management purposes, but changes in the price of natural gas can affect the overall supply and demand of natural gas, which in turn does affect our results of operations. We deliver to a broad mix of customers including LDCs, municipalities, interstate and intrastate pipelines, direct industrial users, electric power generation plants, marketers and producers. In addition to serving directly connected markets, our pipeline systems have indirect market access to the northeastern and southeastern United States through interconnections with unaffiliated pipelines.

Our business is affected by trends involving natural gas price levels and natural gas price spreads, including spreads between physical locations on our pipeline system, which affects our transportation revenues, and spreads in natural gas prices across time (for example summer to winter), which primarily affects our PAL and storage revenues. High natural gas prices in recent years have helped to drive increased production levels in producing locations such as the Bossier Sands and Barnett Shale gas producing regions in East Texas, which has resulted in additional supply being available on the west side of our system. This has resulted in widened west-to-east basis differentials which have benefited our transportation revenues. The high natural gas prices have also driven increased production in regions such as the Fayetteville Shale in Arkansas and the Caney Woodford Shale in Oklahoma, which, together with the higher production levels in East Texas, have formed the basis for several pipeline expansion projects including those being undertaken by us. Wide spreads in natural gas prices between time periods during the past two to three years, for example fall 2006 to spring 2007, were favorable for our PAL and interruptible storage services during that period. These spreads decreased substantially in 2007, which resulted in reduced PAL and interruptible storage revenues. We cannot predict future time period spreads or basis differentials.

Critical Accounting Policies and Estimates

Certain amounts included in or affecting our consolidated financial statements and related disclosures must be estimated, requiring us to make certain assumptions with respect to values or conditions that cannot be known with certainty at the time the financial statements are prepared. These estimates and assumptions affect the amounts we report for assets and liabilities and our disclosure of contingent assets and liabilities in our financial statements. We evaluate these estimates on an ongoing basis, utilizing historical experience, consultation with third parties and other methods we consider reasonable. Nevertheless, actual results may differ significantly from our estimates. Any effects on our business, financial position or results of operations resulting from revisions to these estimates are recorded in the periods in which the facts that give rise to the revisions become known.

Earnings per Unit

We calculate net income per limited partner unit in accordance with Emerging Issues Task Force (EITF) Issue No. 03-6, *Participating Securities and the Two-Class Method under FASB Statement No. 128*. In Issue 3 of EITF No. 03-6, the EITF reached a consensus that undistributed earnings for a period should be allocated to a participating security based on the contractual participation rights of the security to share in those earnings as if all of the earnings for the period had been distributed. Our general partner holds contractual participation rights which are incentive distribution rights in accordance with the partnership agreement as described in Item 5 of this Report under “Incentive Distribution Rights.” The amounts reported for net income per limited partner unit on the Consolidated Statements of Income for the years ended December 31, 2007 and 2006, were adjusted to take into account an assumed incremental allocation to the general partner's incentive distribution rights. Payments made on account of the incentive distribution rights are determined in relation to actual declared distributions.

Regulation

Under the FERC’s regulations certain revenues that we collect may be subject to possible refunds to our customers. Accordingly, during an open rate case, estimates of rate refund reserves are recorded considering regulatory proceedings, advice of counsel and estimated risk-adjusted total exposure, as well as other factors. At December 31, 2007 and 2006, there were no liabilities for any open rate case recorded on our Consolidated Balance Sheets. Currently, neither of our operating subsidiaries is involved in an open general rate case.

SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation*, requires rate-regulated public utilities to account for and report assets and liabilities consistent with the economic effect of the manner in which independent third-party regulators establish rates. In applying SFAS No. 71, Texas Gas records certain costs and benefits as regulatory assets and liabilities, respectively, in order to provide for recovery from or refund to customers in future periods. Gulf South does not apply SFAS No. 71, because certain services provided by it are priced using market-based rates and competition in its market area can result in discounts from the maximum allowable cost-based rates being granted to customers, such that the application of SFAS No. 71 is not appropriate.

The storage facilities operated by our operating subsidiaries store gas that is owned by them as well as gas owned by customers. Due to its method of accounting for storage, volumes held on behalf of others by Gulf South are not reflected on the Consolidated Balance Sheets. Consistent with the method of storage accounting elected by Texas Gas and the risk-of-loss provisions included in its tariff, Texas Gas reflects an equal and offsetting receivable and payable for certain customer-owned gas in its facilities for certain storage and related services. For further discussion of our gas in storage, please see Note 2 in Item 8 of this Report.

Environmental Liabilities

Our environmental liabilities are based on management’s best estimate of the undiscounted future obligation for probable costs associated with environmental assessment and remediation of our operating sites. These estimates are based on evaluations and discussions with counsel and operating personnel and the current facts and circumstances related to these environmental matters. At December 31, 2007, we had accrued approximately $17.0 million for environmental matters. Our environmental accrued liabilities could change substantially in the future due to factors such as the nature and extent of any contamination, changes in remedial requirements, technological changes, discovery of new information, and the involvement of and direction taken by the Environmental Protection Agency, the FERC and other governmental authorities on these matters. We continue to conduct environmental assessments and are implementing a variety of remedial measures that may result in increases or decreases in the total estimated environmental costs.

Impairment

At June 30, 2007, the carrying value of our Magnolia storage expansion project was tested for impairment. As a result of the impairment test, we recognized a $14.7 million impairment charge representing the carrying value of the storage cavern. In determining that the fair value of the cavern was zero, estimates and assumptions were made regarding the cash flows associated with the storage cavern disposal through sale or abandonment. Certain costs remain inestimable related to potential regulatory or contractual obligations associated with abandonment of the storage cavern. We believe that alternative uses for the storage cavern may be possible in the hands of a third-party, and will pursue these options with the lessor, however, we have assumed no future cash flows related to these options in our impairment analysis. In assessing the carrying value of the other associated facilities which include pipeline, compressors and other equipment and facilities, we assumed that the facilities would be used in conjunction with a replacement storage cavern to be developed. Our expected cash flows related to the other facilities include the cost of developing a new cavern and revenues from the sale of storage services to third-parties over the useful life of the asset. If storage spreads were to compress appreciably or significant difficulties were to arise in the development of the cavern, the actual cash flows could differ materially from the expected cash flows used in assessing the carrying value of the facilities which could result in the recognition of an additional impairment charge. If it is determined in the future that the assets cannot be used in conjunction with a new cavern, we may be required to record an additional impairment charge at the time that determination is made.

Jackson Storage Gas Loss

Our Jackson, Mississippi aquifer storage facility has a working gas capacity of approximately 5.0 Bcf and is primarily used for operational purposes. In the fourth quarter 2007, it was determined that, based upon tests used to estimate the amount of gas stored in the facility, gas loss had occurred in the range of 1.3 to 1.7 Bcf. As a result of the estimated gas loss, we recognized a charge of $0.7 million to Operation and maintenance expense in the fourth quarter 2007. This amount was determined by applying the carrying value of gas in the facility of $0.53 per million British thermal units (MMBtu), to the low end of the range of estimated gas loss of 1.3 Bcf. An assessment is underway to determine whether the gas will need to be replaced in order to operate the facility and support pipeline operations. A more comprehensive test of the field will be performed in the second quarter 2008. If the pending test results indicate that the actual gas loss is greater than the estimated 1.3 Bcf, this could result in a future adjustment to the estimate.

Goodwill

As of December 31, 2007, we had $163.5 million of goodwill recorded as an asset on our Consolidated Balance Sheets. SFAS No. 142, *Goodwill and Other Intangible Assets,* requires the evaluation of goodwill for impairment at least annually or more frequently if events and circumstances indicate that the asset might be impaired.

An impairment test performed in accordance with SFAS No. 142 requires that a reporting unit's fair value be estimated. We used a discounted cash flow model to estimate the fair value of the reporting unit, and that estimated fair value was compared to the carrying amount, including goodwill. The estimated fair value was in excess of the carrying amount at December 31, 2007, and accordingly no impairment was recognized. Judgments and assumptions were used in management's estimate of discounted future cash flows used to calculate the fair value of the reporting unit, including our five-year financial plan operating results, the long-term outlook for growth in natural gas demand in the U.S. and systematic or diversifiable risk used in the calculation of the applied discount rate under the capital asset pricing model. The use of alternate judgments and/or assumptions could result in the recognition of an impairment charge in the financial statements.

Defined Benefit Plans

We are required to make a significant number of assumptions in order to estimate the liabilities and costs related to our pension and postretirement benefit obligations to employees under our benefit plans. The assumptions that have the most impact on pension costs are the discount rate, the expected return on plan assets and the rate of compensation increases. These assumptions are evaluated relative to current market factors in the United States such as inflation, interest rates and fiscal and monetary policies, as well as our policies regarding management of the plans such as the allocation of plan assets among investment options. Changes in these assumptions can have a material impact on pension obligations and pension expense.

In determining the discount rate assumption, we utilize current market information and liability information provided by our plan actuaries, including a discounted cash flow analysis of our pension and postretirement obligations. In particular, the basis for our discount rate selection was the yield on indices of highly rated fixed income debt securities with durations comparable to that of our plan liabilities. The Moody’s Aa Corporate Bond Index is consistently used as the basis for the change in discount rate from the last measurement date with this measure confirmed by the yield on other broad bond indices. Additionally, we supplement our discount rate decision with a yield curve analysis. The yield curve is applied to expected future retirement plan payments to adjust the discount rate to reflect the cash flow characteristics of the plans. The yield curve is developed by the plans’ actuaries and is a hypothetical AA/Aa yield curve represented by a series of annualized discount rates reflecting bond issues having a rating of Aa or better by Moody’s Investors Service, Inc. or a rating of AA or better by Standard & Poor's.

Further information on our pension and postretirement benefit obligations is included in Note 9 in Item 8 of this Report.

Financial Analysis of Operations

We derive our revenues primarily from the interstate transportation and storage of natural gas for third parties. Transportation and storage services are provided under firm and interruptible service agreements. Item 1, Nature of Contracts, contains more information about the nature of our revenues. Our operating costs and expenses typically do not vary significantly based upon the amount of gas transported, with the exception of fuel consumed at Gulf South’s compressor stations, which is part of Operation and maintenance expenses. We charge shippers for fuel in accordance with each pipeline’s individual tariff guidelines and Gulf South’s fuel recoveries are included as part of Gas transportation revenues. The following analysis discusses our financial results of operations for the years 2007, 2006 and 2005.

2007 Compared with 2006

Our net income for the year ended December 31, 2007, increased $30.2 million, or 15.3%, from 2006. The primary drivers for the increase were higher revenues from strong demand for firm transportation services, including pipeline system expansion and related fuel revenues. Higher operating expenses driven by a variety of factors, mainly charges for impairment and remediation costs associated with certain assets, increased fuel and higher depreciation and amortization, were substantially offset by higher interest income. The 2007 results were also favorably impacted by a gain on the sale of storage gas associated with a storage expansion project, which was accounted for as a reduction of operating expenses.

Total operating revenues increased $35.7 million, or 5.9%, to $643.3 million for the year ended December 31, 2007, compared to $607.6 million for the year ended December 31, 2006, primarily due to:

- $23.4 million increase in gas transportation fees due to higher reservation rates, including $8.9 million from new contracts associated with the Carthage, Texas to Keatchie, Louisiana pipeline expansion which was in service for all of 2007;
- $11.9 million increase in fuel revenues due to increased retained volumes from higher system utilization including amounts associated with pipeline expansion; and
- $4.1 million increase from the settlement of a claim related to a firm transportation agreement in the Calpine bankruptcy proceeding.

Operating costs and expenses increased $23.5 million, or 6.6%, to $377.2 million for the year ended December 31, 2007, compared to $353.7 million for the year ended December 31, 2006, primarily due to:

- $14.7 million loss from impairment of the Magnolia storage facility in the second quarter 2007;
- $9.3 million in charges associated with offshore pipeline assets in the South Timbalier Bay area, offshore Louisiana, including $4.8 million related to re-covering the pipeline and a $4.5 million impairment charge;
- $6.9 million increase in fuel costs due to an increase in gas usage;
- $6.0 million increase in depreciation and amortization from increases in our asset base;
- $5.0 million increase in property and other taxes due to increases in the valuation of our asset base;
- $3.8 million increase related to termination of an agreement with a construction contractor on the Southeast expansion project; and
- $22.0 million decrease from a gain on the sale of gas associated with the Western Kentucky storage expansion project which was reported in Net gain on disposal of operating assets and related contracts.

Total other deductions declined by $18.6 million, or 33.2%, to $37.5 million for the year ended December 31, 2007, compared to $56.1 million for the year ended December 31, 2006. The decline is primarily due to an increase in interest income of $17.3 million as a result of higher levels of invested cash which we accumulated through sales of our debt and equity to finance the cost of our expansion projects.

2006 Compared with 2005

Our net income for the year ended December 31, 2006 increased $96.6 million or 95.7% from 2005. The primary drivers for the increase were higher PAL, gas storage and gas transportation revenues and a change in tax status concurrent with our IPO in November 2005, as a result of which we ceased recording a charge-in-lieu of income taxes in our results of operations.

Total operating revenues increased $47.2 million, or 8.4%, to $607.6 million for the year ended December 31, 2006, compared to $560.4 million for the year ended December 31, 2005, primarily due to:

- $38.5 million increase in gas storage and PAL revenues mainly due to favorable natural gas price spreads and volatility in forward natural gas prices;
- $26.0 million increase in firm transportation revenues, excluding fuel, primarily due to higher reservation rates and additional capacity reserved by shippers due to increased production in the East Texas region; and
- $5.3 million increase due mainly to hurricane insurance recoveries received in 2006 and gas lost in 2005 related to hurricanes.

The increases were partly offset by:

- $10.5 million decrease in interruptible transportation revenues due in part to customers shifting to firm services and supply disruptions caused by the hurricanes;
- $7.1 million decrease in fuel retained due to lower realized natural gas prices and reduced throughput; and
- $5.5 million decrease in revenues from the amortization of acquired executory contracts.

Operating costs and expenses increased by $8.7 million, or 2.5%, to $353.7 million for the year ended December 31, 2006, compared to $345.0 million for the year ended December 31, 2005. This increase is primarily due to:

- $12.6 million increase in outside services and overheads mainly due to growth in operations and regulatory compliance;
- $12.2 million from the sale of storage gas related to Phase I of our Western Kentucky storage expansion project reported in Net gain on disposal of operating assets and related contracts in 2005;
- $10.2 million higher employee benefits costs comprised mainly of $6.3 million from the amortization of a regulatory asset for postretirement benefits as a result of the Texas Gas rate case settlement and $3.5 million from a special termination benefit charge recorded as a result of the early retirement incentive program; and
- $3.7 million from an increase in depreciation and amortization due to increases in our asset base and $2.6 million increased expense from the lease of third-party pipeline capacity.

The increases were partly offset by:

- $18.2 million decrease in hurricane-related costs from $7.3 million of hurricane-related insurance recoveries recognized in 2006 and a reduction in hurricane-related operating expenses from amounts incurred in 2005;
- $14.9 million decrease in company-used gas due to operational efficiencies, lower natural gas prices and reduced throughput resulting in decreased usage.

Total other deductions increased by $1.2 million, or 2.2%, of which $2.1 million is primarily due to interest expense related to borrowings under our revolving credit facility and the issuance of new debt in November 2006, offset by an increase in interest income.

Liquidity and Capital Resources

We are a partnership holding company and derive all of our operating cash flow from our operating subsidiaries. Our operating subsidiaries use funds from their respective operations to fund their operating activities and maintenance capital requirements, service their indebtedness and make advances or distributions to Boardwalk Pipelines. Boardwalk Pipelines uses cash provided from the operating subsidiaries and, as needed, borrowings under its revolving credit facility discussed below, to service its outstanding indebtedness and, when available, make distributions or advances to us to fund our distributions to unitholders.

Our operating subsidiaries participate in a cash management program to the extent they are permitted under FERC regulations. Under the cash management program, depending on whether a participating subsidiary has short-term cash surpluses or cash requirements, Boardwalk Pipelines either provides cash to them or they provide cash to Boardwalk Pipelines.

Maintenance Capital Expenditures

Maintenance capital expenditures were $47.1 million, $41.7 million and $52.9 million in 2007, 2006 and 2005. We expect to fund our 2008 maintenance capital expenditures of approximately $60.0 million from our operating cash flows.

Expansion Capital Expenditures

Expansion capital expenditures were $1,162.7 million, $158.6 million and $30.1 million in 2007, 2006 and 2005. As discussed above in Item 1, Business – Expansion Projects, we have undertaken significant capital expansion projects, substantially all of which have been or are expected to be funded with proceeds from equity and debt financings.

Since our IPO through December 31, 2007, we have raised $726.0 million through issuances of equity limited partnership units and contributions from our general partner and $743.6 million through issuances of unsecured notes by us and our subsidiaries, as described below under Equity and Debt Financing, and in Note 7 to the consolidated financial statements contained in Item 8 of this Report. At December 31, 2007, we had approximately $317.3 million in cash and $814.4 million of borrowing capacity available under our $1.0 billion revolving credit facility discussed below.

We expect to incur expansion capital expenditures of approximately $3.1 billion in 2008 and approximately $0.2 billion in 2009 to complete our pipeline expansion projects, based upon our current cost estimates. However, as noted elsewhere in this report, we have experienced cost increases in these projects and various factors could cause our costs to exceed that amount. We expect to finance our remaining pipeline expansion capital costs through equity financings and the incurrence of debt, including sales of debt by us and our subsidiaries, and borrowings under our revolving credit facility, as well as available operating cash flow in excess of our operating needs. However, the impact of the cost increases we have experienced and may experience in the future to complete our expansion capital projects could adversely impact our financing costs, which could have a material adverse affect on our results of operations, financial condition and cash flows. See Item 1A, Risk Factors – We are undertaking large, complex expansion projects which involve significant risks that may adversely affect our business. See also Item 1 – Pipeline Expansion Projects.

Equity and Debt Financing

In November 2007, we completed an offering of 7.5 million of our common units at a price of $30.90 per unit. The offering resulted in net proceeds of $232.8 million, after deducting underwriting discounts and offering expenses of $3.7 million and including $4.7 million received from our general partner to maintain its 2.0% interest in us. After the offering, we have 90.7 million common units and 33.1 million subordinated units issued and outstanding, of which 37.4 million common units are held by the public.

In August 2007, we sold $225.0 million of 5.75% senior unsecured notes of Gulf South due August 15, 2012, and $275.0 million of 6.30% senior unsecured notes of Gulf South due August 15, 2017. We received net proceeds of approximately $495.3 million after deducting initial purchaser discounts and offering expenses of $4.7 million.

In March 2007, we completed a public offering of 8.0 million of our common units at a price of $36.50 per unit. We received proceeds of approximately $293.8 million, net of underwriting discounts and offering expenses of $4.2 million and including approximately $6.0 million from the general partner to maintain its 2.0% general partner interest.

The proceeds of these offerings have been and will be primarily used to fund capital expenditures associated with our expansion projects.

In August 2007, we entered into a Treasury rate lock for a notional amount of $150.0 million of principal to hedge the risk attributable to changes in the risk-free component of forward 10-year interest rates through February 1, 2008. The reference rate on the Treasury rate lock was 4.74%. On February 1, 2008, we paid the counterparty approximately $15.0 million to settle the rate lock. The Treasury lock was designated as a cash flow hedge in accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities,* as amended; therefore the loss will be recognized in Interest expense over the term of the related debt to be issued.

Credit Facility

We maintain a $1.0 billion revolving credit facility, which was increased from $700.0 million in November 2007, under which Boardwalk Pipelines, Gulf South and Texas Gas each may borrow funds, up to applicable sub-limits. Interest on amounts drawn under the credit facility is payable at a floating rate equal to an applicable spread per annum over the London Interbank Offered Rate (LIBOR) or a base rate defined as the greater of the prime rate or the Federal funds rate plus 50 basis points. Under the terms of the agreement, each of the borrowers must maintain a minimum ratio, as of the last day of each fiscal quarter, of consolidated total debt to consolidated earnings before income taxes, depreciation and amortization (as defined in the agreement), measured for the preceding twelve months, of not more than five to one. As of December 31, 2007, we were in compliance with all the covenant requirements under our credit agreement and no funds were drawn under this facility. However, at December 31, 2007, we had outstanding letters of credit under the facility for $185.6 million to support certain obligations associated with the Fayetteville Lateral and Gulf Crossing expansion projects which reduced the available capacity under the facility by such amount. The revolving credit facility has a maturity date of June 29, 2012.

Contractual Obligations

The following table summarizes significant contractual cash payment obligations as of December 31, 2007, by period (in millions):

	Total	Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years
Principal payments on long-term debt	$ 1,860.0	-	-	$ 225.0	$ 1,635.0
Interest on long-term debt	963.7	$ 103.6	$ 207.4	207.4	445.3
Capital commitments	851.1	834.7	16.4	-	-
Lease commitments	36.7	6.7	10.8	6.0	13.2
Total	$ 3,711.5	$ 945.0	$ 234.6	$ 438.4	$ 2,093.5

Pursuant to the settlement of the Texas Gas rate case in 2006, we are required to annually fund an amount to the Texas Gas pension plan equal to the amount of actuarially determined net periodic pension cost, including a minimum of $3.0 million. The above table does not reflect commitments we have made after December 31, 2007, relating to our expansion projects. For information on these projects, please read "Capital Expenditures" above.

Changes in cash flow from operating activities

Net cash provided by operating activities increased $26.2 million, or 10.3%, to $281.7 million for the year ended December 31, 2007, compared to $255.5 million for the comparable 2006 period, primarily due to:

- $16.0 million increase in cash due to gas purchases made in 2006;
- $8.5 million increase in cash due to the timing of expenditures; and
- $3.0 million increase in cash from the change in net income, excluding non-cash items such as depreciation and amortization, impairment charges and recognition of previously deferred revenues.

Changes in cash flow from investing activities

Net cash used in investing activities increased $988.8 million to $1.2 billion for the year ended December 31, 2007, compared to $191.5 million for the comparable 2006 period, primarily due to an increase in capital expenditures mainly for our expansion projects.

Changes in cash flow from financing activities

Net cash provided by financing activities increased $547.7 million to $816.9 million for the year ended December 31, 2007, compared to $269.2 million for the comparable 2006 period, primarily due to:

- $327.2 million increase in net proceeds from the sale of common units and related general partner capital contributions;
- $157.0 million increase in net proceeds from the issuance of long term debt; and
- $132.1 million decrease in cash used from the payment of notes and other long term debt in 2006.

These increases were partly offset by $68.6 million increase in cash distributions to unitholders and the general partner.

Impact of Inflation

We have experienced increased costs in recent years due to the effect of inflation on the cost of labor, benefits, materials and supplies, and property, plant and equipment (PPE). A portion of the increased labor and materials and supplies costs have directly affected income through increased operating and maintenance costs. The cumulative impact of inflation over a number of years has resulted in increased costs for current replacement of productive facilities. The majority of our PPE and materials and supplies is subject to rate-making treatment, and under current FERC practices, recovery is limited to historical costs. Amounts in excess of historical cost are not recoverable unless a rate case is filed. However, cost-based regulation, along with competition and other market factors, limit our ability to price jurisdictional services or products to ensure recovery of inflation's effect on costs.

Off-Balance Sheet Arrangements

At December 31, 2007, we had no guarantees of off-balance sheet debt to third parties, no debt obligations that contain provisions requiring accelerated payment of the related obligations in the event of specified levels of declines in credit ratings, and no other off-balance sheet arrangements.

Recent Accounting Pronouncements

For a discussion regarding recent accounting pronouncements, please read Note 15 in Item 8 of this Report.

Calpine Energy Services (Calpine) Settlement

In 2002 and 2003, Calpine entered into two 20-year transportation agreements with Gulf South. In December 2005, Calpine filed for Chapter 11 Bankruptcy protection and in early 2006 discontinued making payments on one of the transportation agreements. Gulf South continued to invoice Calpine under the transportation agreements and fully reserved the revenues associated with the contract on which Calpine was not making payments. In December 2007, Gulf South and Calpine filed a stipulation and agreement with the Bankruptcy court, which was approved in January 2008, to terminate the firm transportation agreement on which Calpine was delinquent, and to settle all of Gulf South's claims in the Bankruptcy proceedings for approximately $16.5 million. The claim was to be paid in the form of Calpine stock, along with other general creditors having claims in the Bankruptcy proceeding. In January 2008, we sold the Bankruptcy claim to a third party and received a cash payment of approximately $15.3 million. The assignment is with recourse subject to the issuance of Calpine stock in the full amount of the claim. As a result of the settlement, in 2007 we recognized $4.1 million in Gas transportation revenues related to invoiced amounts past due, which were previously reserved. The remainder of the settlement amount will be recognized upon full payment of the settlement amount by Calpine.

Forward-Looking Statements

Investors are cautioned that certain statements contained in this report, as well as some statements in periodic press releases and some oral statements made by our officials and our subsidiaries during presentations about us, are "forward-looking." Forward-looking statements include, without limitation, any statement that may project, indicate or imply future results, events, performance or achievements, and may contain the words "expect," "intend," "plan," "anticipate," "estimate," "believe," "will likely result," and similar expressions. In addition, any statement made by our management concerning future financial performance (including future revenues, earnings or growth rates), ongoing business strategies or prospects, and possible actions by our partnership or its subsidiaries, are also forward-looking statements.

Forward-looking statements are based on current expectations and projections about future events and are inherently subject to a variety of risks and uncertainties, many of which are beyond our control that could cause actual results to differ materially from those anticipated or projected. These risks and uncertainties include, among others:

- We may not complete projects, including growth or expansion projects, that we have commenced or will commence, or we may complete projects on materially different terms, cost or timing than anticipated and we may not be able to achieve the intended economic or operational benefits of any such project, if completed.

- The successful completion, timing, cost, scope and future financial performance of our expansion projects could differ materially from our expectations due to availability of contractors or equipment, weather, difficulties or delays in obtaining regulatory approvals or denied applications, land owner opposition, the lack of adequate materials, labor difficulties or shortages, expansion costs that are higher than anticipated and numerous other factors beyond our control.

- We may not complete any future debt or equity financing transaction.

- The gas transmission and storage operations of our subsidiaries are subject to rate-making policies and actions by the FERC or customers that could have an adverse impact on the rates we charge and our ability to recover our income tax allowance, our full cost of operating our pipelines and a reasonable return.

- We are subject to laws and regulations relating to the environment and pipeline operations which may expose us to significant costs, liabilities and loss of revenues. Any changes in such regulations or their application could negatively affect our business, financial condition and results of operations.

- Our operations are subject to operational hazards and unforeseen interruptions for which we may not be adequately insured.

- The cost of insuring our assets may increase dramatically.

- Because of the natural decline in gas production connected to our system, our success depends on our ability to obtain access to new sources of natural gas, which is dependent on factors beyond our control. Any decrease in supplies of natural gas in our supply areas could adversely affect our business, financial condition and results of operations.

- Successful development of LNG import terminals in the eastern or northeastern United States could reduce the demand for our services.

- We may not be able to maintain or replace expiring gas transportation and storage contracts at favorable rates.

- Significant changes in natural gas prices could affect supply and demand, reducing system throughput and adversely affecting our revenues.

Developments in any of these areas could cause our results to differ materially from results that have been or may be anticipated or projected. Forward-looking statements speak only as of the date of this report and we expressly disclaim any obligation or undertaking to update these statements to reflect any change in our expectations or beliefs or any change in events, conditions or circumstances on which any forward-looking statement is based.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Our debt has been issued at fixed rates, therefore interest expense would not be impacted by changes in interest rates. Total long-term debt at December 31, 2007, had a carrying value of $1.8 billion and a fair value of $1.8 billion. A 100 basis point increase in interest rates on our fixed rate debt would result in a decrease in fair value of approximately $118.8 million at December 31, 2007. A 100 basis point decrease would result in an increase in fair value of approximately $129.3 million at December 31, 2007. The weighted-average interest rate of our long-term debt was 5.82% at December 31, 2007.

In August 2007, we entered into a Treasury rate lock for a notional amount of $150.0 million of principal to hedge the risk attributable to changes in the risk-free component of forward 10-year interest rates through February 1, 2008. The reference rate on the rate lock was 4.74%. On February 1, 2008, we paid the counterparty approximately $15.0 million to settle the rate lock. The Treasury lock was designated as a cash flow hedge in accordance with SFAS No. 133, therefore the loss will be recognized in Interest expense over the term of the related debt to be issued.

Certain volumes of our gas stored underground are available for sale and subject to commodity price risk. At December 31, 2007, approximately $16.3 million of gas stored underground, which we own and carry as current Gas stored underground, is exposed to commodity price risk. We utilize derivatives to hedge certain exposures to market price fluctuations on the anticipated operational sales of gas.

In the second quarter 2007, we entered into natural gas price swaps to hedge exposure to prices associated with the purchase of 2.1 Bcf of natural gas to be used for line pack for our Gulf Crossing and Southeast expansion projects, approximately 1.3 Bcf of which remained outstanding at December 31, 2007. The derivatives were not designated as hedges in accordance with SFAS No. 133 and were marked to fair value through earnings resulting in a loss of $1.0 million for the year ended December 31, 2007. Changes in the fair value of the derivatives will be recognized in earnings each quarter until settlement. When the gas is purchased, the ultimate cost will be recorded to Property, Plant and Equipment and recognized in earnings as the property is depreciated. A $1.00 increase in the price of NYMEX natural gas futures would result in the recognition of a $1.3 million gain in earnings. Conversely, a $1.00 decrease would result in the recognition of a $1.3 million loss.

With the exception of the derivatives related to line pack gas purchases referred to above, the derivatives related to the sale or purchase of natural gas, cash for fuel reimbursement and debt issuance generally qualify for cash flow hedge accounting under SFAS No. 133 and are designated as such. The effective component of related unrealized gains and losses resulting from changes in fair values of the derivatives contracts designated as cash flow hedges are deferred as a component of accumulated other comprehensive income. The deferred gains and losses are recognized in the Consolidated Statements of Income when the anticipated transactions affect earnings. Generally, for gas sales and cash for fuel reimbursement, any gains and losses on the related derivatives would be recognized in Operating Revenues. Any gains and losses on the derivatives related to the line pack gas purchases would be recognized in Miscellaneous other income, net.

The changes in fair values of the derivatives designated as cash flow hedges are expected to, and do, have a high correlation to changes in value of the anticipated transactions. Each reporting period we measure the effectiveness of the cash flow hedge contracts. To the extent the changes in the fair values of the hedge contracts do not effectively offset the changes in the estimated cash flows of the anticipated transactions, the ineffective portion of the hedge contracts is currently recognized in earnings. If the anticipated transactions are deemed no longer probable to occur, hedge accounting would be terminated and changes in the fair values of the associated derivative financial instruments would be recognized currently in earnings.

We are exposed to credit risk relating to the risk of loss resulting from the nonperformance by a customer of its contractual obligations. Our exposure generally relates to receivables for services provided, as well as volumes owed by customers for imbalances or gas lent by us to them, generally under PAL and NNS. We maintain credit policies intended to minimize credit risk and actively monitor these policies. Natural gas price volatility has increased dramatically in recent years, which has materially increased credit risk related to gas loaned to customers. As of December 31, 2007, the amount of gas loaned out by our subsidiaries was 12.7 trillion British thermal units (TBtu) and, assuming an average market price during December 2007 of $7.13 per MMBtu, the market value of gas loaned out at December 31, 2007, would have been approximately $90.6 million. If any significant customer of ours should have credit or financial problems resulting in a delay or failure to repay the gas they owe to us, this could have a material adverse effect on our financial condition, results of operations and cash flows.

As of December 31, 2007, our cash and cash equivalents were invested primarily in mutual funds. Due to the short-term nature and type of our investments, a hypothetical 10.0% increase in interest rates would not have a material effect on the fair market value of our portfolio. Since we have the ability to liquidate this portfolio, we do not expect our Consolidated Statements of Income or Cash Flows to be materially impacted by the effect of a sudden change in market interest rates on our investment portfolio.

During 2007, we began investing in short-term investments such as U.S. Government securities, primarily Treasury notes, under repurchase agreements. Generally, we have engaged in overnight repurchase transactions where purchased securities are sold back to the counterparty the following business day. Pursuant to the master repurchase agreements, we take actual possession of the purchased securities. In the event of default by the counterparty under the agreement, the repurchase would be deemed immediately to occur and we would be entitled to sell the securities in the open market, or give the counterparty credit based on the market price on such date, and apply the proceeds (or deemed proceeds) to the aggregate unpaid repurchase amounts and any other amounts owed by the counterparty. We had no investments under repurchase agreements at December 31, 2007, however since then we have reinitiated our program of investing in short-term repurchase agreements.

Item 8. Financial Statements and Supplementary Data

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Boardwalk GP, LLC and the Partners of Boardwalk Pipeline Partners, LP

We have audited the accompanying consolidated balance sheets of Boardwalk Pipeline Partners, LP and subsidiaries (the “Partnership”) as of December 31, 2007 and 2006, and the related consolidated statements of income, member’s equity and partners’ capital, comprehensive income, and cash flows for each of the three years in the period ended December 31, 2007. Our audits also included the financial statement schedule included in the Index at Item 15. These financial statements and financial statement schedule are the responsibility of the Partnership's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Boardwalk Pipeline Partners, LP and subsidiaries as of December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

As discussed in Note 1 to the consolidated financial statements, the accompanying financial statements reflect a change in the Partnership’s tax status.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Partnership's internal control over financial reporting as of December 31, 2007, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 26, 2008 expressed an unqualified opinion on the Partnership's internal control over financial reporting.

DELOITTE & TOUCHE LLP
Chicago, Illinois
February 26, 2008

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of
Boardwalk GP, LLC and the Partners of Boardwalk Pipeline Partners, LP

We have audited the internal control over financial reporting of Boardwalk Pipeline Partners, LP and subsidiaries (the "Partnership") as of December 31, 2007, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Partnership's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Partnership's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Boardwalk Pipeline Partners, LP and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedule as of and for the year ended December 31, 2007 of the Partnership and our report dated February 26, 2008 expressed an unqualified opinion on those financial statements and financial statement schedule and included an explanatory paragraph regarding a change in the Partnership's tax status.

DELOITTE & TOUCHE LLP
Chicago, Illinois
February 26, 2008

BOARDWALK PIPELINE PARTNERS, LP

CONSOLIDATED BALANCE SHEETS
(Thousands of Dollars)

ASSETS	December 31, 2007	December 31, 2006
Current Assets:		
Cash and cash equivalents	$ 317,319	$ 399,032
Receivables:		
Trade, net	60,661	54,082
Other	12,748	12,759
Gas Receivables:		
Transportation and exchange	12,467	9,115
Storage	1,266	11,704
Inventories	16,581	14,110
Costs recoverable from customers	6,358	11,236
Gas stored underground	16,322	14,001
Prepaid expenses and other current assets	11,927	22,117
Total current assets	455,649	548,156
Property, Plant and Equipment:		
Natural gas transmission plant	2,392,503	1,832,006
Other natural gas plant	223,952	213,926
	2,616,455	2,045,932
Less—accumulated depreciation and amortization	262,477	187,412
	2,353,978	1,858,520
Construction work in progress	951,433	165,916
Property, plant and equipment, net	3,305,411	2,024,436
Other Assets:		
Goodwill	163,474	163,474
Gas stored underground	172,438	161,537
Costs recoverable from customers	15,870	19,767
Other	44,464	33,929
Total other assets	396,246	378,707
Total Assets	$ 4,157,306	$ 2,951,299

The accompanying notes are an integral part of these consolidated financial statements.

BOARDWALK PIPELINE PARTNERS, LP

CONSOLIDATED BALANCE SHEETS
(Thousands of Dollars, except number of units)

LIABILITIES AND PARTNERS' CAPITAL	December 31, 2007	December 31, 2006
Current Liabilities:		
Payables:		
Trade	$ 190,639	$ 56,604
Affiliates	1,292	3,014
Other	5,089	14,459
Gas Payables:		
Transportation and exchange	17,849	15,485
Storage	35,250	42,127
Accrued taxes, other	20,164	16,082
Accrued interest	30,801	19,376
Accrued payroll and employee benefits	22,337	18,198
Construction retainage	32,195	2,336
Deferred income	7,235	22,147
Other current liabilities	26,459	18,590
Total current liabilities	389,310	228,418
Long –Term Debt	1,847,914	1,350,920
Other Liabilities and Deferred Credits:		
Pension and postretirement benefits	17,211	15,761
Asset retirement obligation	16,059	14,307
Provision for other asset retirement	42,380	39,644
Other	41,430	29,742
Total other liabilities and deferred credits	117,080	99,454
Commitments and Contingencies		
Partners' Capital:		
Common units - 90,656,122 and 75,156,122 common units issued and outstanding as of December 31, 2007 and 2006	1,473,924	941,792
Subordinated units - 33,093,878 units issued and outstanding as of December 31, 2007 and 2006	291,662	285,543
General partner	33,204	22,060
Accumulated other comprehensive income, net of tax	4,212	23,112
Total partners' capital	1,803,002	1,272,507
Total Liabilities and Partners' Capital	$ 4,157,306	$ 2,951,299

The accompanying notes are an integral part of these consolidated financial statements.

BOARDWALK PIPELINE PARTNERS, LP

CONSOLIDATED STATEMENTS OF INCOME
(Thousands of Dollars, except earnings per unit and number of units)

	For the Year Ended December 31,		
	2007	**2006**	**2005**
Operating Revenues:			
Gas transportation	$ 529,717	$ 508,241	$ 505,148
Parking and lending	42,793	49,163	21,426
Gas storage	39,429	32,396	21,667
Other	31,329	17,842	12,225
Total operating revenues	643,268	607,642	560,466
Operating Costs and Expenses:			
Operation and maintenance	173,759	161,279	174,641
Administrative and general	97,039	97,298	78,752
Depreciation and amortization	81,824	75,771	72,078
Taxes other than income taxes	29,162	24,175	27,361
Asset impairment	19,218	-	-
Net gain on disposal of operating assets and related contracts	(23,767)	(4,829)	(7,846)
Total operating costs and expenses	377,235	353,694	344,986
Operating income	266,033	253,948	215,480
Other Deductions (Income):			
Interest expense	61,023	62,123	60,067
Interest income	(21,489)	(4,202)	(1,478)
Interest income from affiliates, net	(44)	(27)	(2,186)
Miscellaneous other income, net	(1,982)	(1,749)	(1,444)
Total other deductions	37,508	56,145	54,959
Income before income taxes	228,525	197,803	160,521
Income taxes and charge-in-lieu of income taxes *	769	253	49,494
Elimination of cumulative deferred taxes *	-	-	10,102
Net income *	$ 227,756	$ 197,550	$ 100,925

*Results of operations for the year ended December 31, 2005, reflect a change in the tax status associated with Boardwalk Pipeline Partners, LP and Boardwalk Pipelines coincident with the IPO. Boardwalk Pipeline Partners, LP recorded a charge-in-lieu of income taxes and certain state franchise taxes for the period January 1, 2005 through the date of the offering. Pursuant to the change in tax status, Boardwalk Pipeline Partners, LP also eliminated its balance of accumulated deferred income taxes at the date of the offering (as presented in line item "Elimination of cumulative deferred taxes"). The subsidiaries of Boardwalk Pipeline Partners, LP directly incur some income-based state taxes following the date of the offering. See Note 1 to the consolidated financial statements for additional information.

Calculation of limited partners' interest in Net income:	For the Year Ended December 31,		For the Period November 15, 2005 through December 31,
	2007	**2006**	**2005**
Net income	$ 227,756	$ 197,550	$ 35,992
Less general partner's interest in Net income	7,030	3,951	720
Limited partners' interest in Net income	$ 220,726	$ 193,599	$ 35,272
Basic and diluted net income per limited partner unit:			
Common and subordinated units	$ 1.87	$ 1.85	$ 0.35
Cash distribution to common and subordinated unitholders	$ 1.74	$ 1.32	-
Weighted-average number of limited partners units outstanding:			
Common units	82,510,917	68,977,766	68,256,122
Subordinated units	33,093,878	33,093,878	33,093,878

The accompanying notes are an integral part of these consolidated financial statements.

BOARDWALK PIPELINE PARTNERS, LP

CONSOLIDATED STATEMENTS OF CASH FLOWS
(Thousands of Dollars)

	For the Year Ended December 31, 2007	2006	2005
OPERATING ACTIVITIES:			
Net income	$ 227,756	$ 197,550	$ 100,925
Adjustments to reconcile to cash provided by operations:			
Depreciation and amortization	81,824	75,771	72,078
Amortization of deferred costs	8,319	8,758	1,313
Amortization of acquired executory contracts	(1,098)	(3,997)	(9,630)
Provision for deferred income taxes	(17)	(39)	54,682
Asset impairment	19,218	-	-
Gain on disposal of operating assets and related contracts	(23,767)	(4,829)	(7,846)
Changes in operating assets and liabilities:			
Trade and other receivables	(4,141)	(436)	(27,257)
Gas receivables and storage assets	5,446	21,451	(25,474)
Costs recoverable from customers	3,598	(3,968)	(8,215)
Other assets	(15,816)	(15,583)	32,259
Trade and other payables	(15,960)	9,117	(7,461)
Gas payables	(17,935)	(45,066)	35,567
Accrued liabilities	12,929	(8,091)	21,467
Other liabilities	1,347	24,850	(13,694)
Net cash provided by operating activities	281,703	255,488	218,714
INVESTING ACTIVITIES:			
Capital expenditures	(1,209,848)	(200,330)	(82,955)
Proceeds from sale of operating assets	28,741	3,646	4,725
Proceeds from insurance reimbursements and other recoveries	1,726	5,928	4,177
Advances to affiliates, net	(945)	(696)	(28,252)
Net cash used in investing activities	(1,180,326)	(191,452)	(102,305)
FINANCING ACTIVITIES:			
Proceeds from notes payable	-	-	42,100
Payments of notes payable	-	(42,100)	(250,000)
Proceeds from long-term debt, net of issuance costs	495,271	338,307	569,369
Payment of long-term debt	-	(90,000)	(575,000)
Distributions	(204,950)	(136,388)	(131,686)
Proceeds from sale of common units, net of related transaction costs	515,900	195,209	271,398
Capital contribution from parent and general partner	10,689	4,176	6,684
Net cash provided by (used in) financing activities	816,910	269,204	(67,135)
(Decrease) increase in cash and cash equivalents	(81,713)	333,240	49,274
Cash and cash equivalents at beginning of period	399,032	65,792	16,518
Cash and cash equivalents at end of period	$ 317,319	$ 399,032	$ 65,792

The accompanying notes are an integral part of these consolidated financial statements.

BOARDWALK PIPELINE PARTNERS, LP

CONSOLIDATED STATEMENTS OF CHANGES IN MEMBER'S EQUITY AND PARTNERS' CAPITAL
(Thousands of Dollars, except units)

	Paid in Capital	Retained Earnings	Accumulated Other Comp Income (Loss)	Common Units	Subordinated Units	General Partner	Total Partners' Capital
Balance January 1, 2005	$ 1,071,651	$ 21,276	-	-	-	-	-
Add (deduct):							-
Net income	-	64,933	-	-	-	-	-
Capital contribution	6,684	-	-	-	-	-	-
Dividends paid	-	(233,087)	-	-	-	-	-
Other comprehensive income, net of tax	-	-	$ 287	-	-	-	-
Elimination of deferred taxes on accumulated other comprehensive income	-	-	64	-	-	-	-
Balance November 15, 2005	$ 1,078,335	$ (146,878)	$ 351	-	-	-	-
Boardwalk Pipeline Partners, LP							
Add (deduct):							
Capital contribution, including assumption of debt of $250.0 million (53,256,122 common units, 33,093,878 subordinated units and 2% general partner interest)	-	-	$ 351	$ 410,456	$ 255,061	$ 15,941	$ 681,809
Sale of common units, net of related transaction costs (15,000,000 units)	-	-	-	271,398	-	-	271,398
Other comprehensive loss, net of tax	-	-	(525)	-	-	-	(525)
Net income	-	-	-	23,755	11,517	720	35,992
Balance December 31, 2005	-	-	$ (174)	$ 705,609	$ 266,578	$ 16,661	$ 988,674
Add (deduct):							
Net income	-	-	-	130,990	62,609	3,951	197,550
Distributions paid	-	-	-	(90,016)	(43,644)	(2,728)	(136,388)
Sale of common units, net of related transaction costs (6,900,000 units)	-	-	-	195,209	-	-	195,209
Capital contribution	-	-	-	-	-	4,176	4,176
Other comprehensive income, net of tax	-	-	8,483	-	-	-	8,483
Adjustment to initially apply SFAS No. 158, net of tax	-	-	14,803	-	-	-	14,803
Balance December 31, 2006	-	-	$ 23,112	$ 941,792	$ 285,543	$ 22,060	$ 1,272,507
Add (deduct):							
Net income	-	-	-	157,189	63,537	7,030	227,756
Distributions paid	-	-	-	(140,957)	(57,418)	(6,575)	(204,950)
Sale of common units, net of related transaction costs (15,500,000 units)	-	-	-	515,900	-	-	515,900
Capital contribution from general partner	-	-	-	-	-	10,689	10,689
Other comprehensive							

loss, net of tax	-	-	(18,900)	-	-		(18,900)
Balance December 31, 2007	-	-	$ 4,212	$ 1,473,924	$ 291,662	$ 33,204	$ 1,803,002

The accompanying notes are an integral part of these consolidated financial statements.

BOARDWALK PIPELINE PARTNERS, LP

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Thousands of Dollars)

	For the Year Ended December 31, 2007	2006	2005
Net income	$ 227,756	$ 197,550	$ 100,925
Other comprehensive (loss) income:			
(Loss) gain on cash flow hedges	(9,864)	19,405	(2,735)
Reclassification adjustment transferred to Net income from cash flow hedges	(7,336)	(10,922)	2,561
Pension and other postretirement benefits costs	(1,700)	-	-
Total comprehensive income	$ 208,856	$ 206,033	$ 100,751

These accompanying notes are an integral part of these consolidated financial statements.

BOARDWALK PIPELINE PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1: Corporate Structure

Boardwalk Pipeline Partners, LP (the Partnership) is a Delaware limited partnership formed to own and operate the business conducted by Boardwalk Pipelines, LP (Boardwalk Pipelines) and its subsidiaries, Gulf South Pipeline Company, LP (Gulf South) and Texas Gas Transmission, LLC (Texas Gas) (together, the operating subsidiaries). Boardwalk Pipelines Holding Corp. (BPHC) a wholly-owned subsidiary of Loews Corporation (Loews) owns 53.3 million common units and 33.1 million subordinated units constituting approximately 70.0% of the Partnership's equity. Boardwalk GP, LP (Boardwalk GP), an indirect wholly-owned subsidiary of BPHC is the Partnership's general partner and holds a 2.0% general partner interest and all of the incentive distribution rights, further described in Note 10. The Partnership is traded under the symbol "BWP" on the New York Stock Exchange (NYSE).

Basis of Presentation

The accompanying consolidated financial statements of the Partnership were prepared in accordance with accounting principles generally accepted in the United States of America (GAAP).

In connection with the consummation of the Partnership's initial public offering (IPO), BPHC contributed all of the equity interests of Boardwalk Pipelines to the Partnership. This contribution was accounted for as a transfer of assets between entities under common control in accordance with Statement of Financial Accounting Standards (SFAS) No. 141, *Business Combinations*. Therefore, the results of Boardwalk Pipelines prior to November 15, 2005, have been combined with the results of the Partnership subsequent to November 15, 2005, as the consolidated results of the Partnership.

Results of operations for the year ended December 31, 2005, reflect a change in the tax status associated with the Partnership and Boardwalk Pipelines, coincident with the IPO. Prior to converting to a limited partnership on November 15, 2005, Boardwalk Pipelines' taxable income was included in the consolidated federal income tax return of Loews, and Boardwalk Pipelines recorded a charge-in-lieu of income taxes pursuant to a tax sharing agreement with Loews. Accordingly, the Partnership recorded a charge-in-lieu of income taxes of $49.5 million for the period January 1, 2005, through the date of the offering. Pursuant to the change in tax status, the Partnership also eliminated its balance of accumulated deferred income taxes at the date of the offering as presented in Elimination of cumulative deferred taxes on the Consolidated Statements of Income. The subsidiaries of the Partnership directly incur some income-based state taxes which are presented in Income taxes and charge-in-lieu of income taxes on the Consolidated Statements of Income.

Note 2: Accounting Policies

Principles of Consolidation

The consolidated financial statements include the Partnership's accounts and those of its wholly-owned subsidiaries, Boardwalk Pipelines, Gulf South, Texas Gas and Gulf Crossing Pipeline Company, LLC (Gulf Crossing) after elimination of intercompany transactions.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and disclosure of contingent assets and liabilities. On an ongoing basis, the Partnership evaluates its estimates, including but not limited to those related to bad debts, materials and supplies obsolescence, investments, goodwill, property and equipment and other long-lived assets, property taxes, pensions and other postretirement and postemployment benefits, share-based and other incentive compensation, contingent liabilities, revenues subject to refund, and prior to converting to a limited partnership, charge-in-lieu of income taxes. The Partnership bases its estimates on historical experience and on various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results could differ from such estimates.

Segment Information

The Partnership operates in one reportable segment – the operation of interstate natural gas pipeline systems. This segment consists of interstate natural gas pipeline systems originating in the Gulf Coast area and running north and east through Texas, Louisiana, Arkansas, Mississippi, Alabama, Florida, Tennessee, Kentucky, Indiana, Ohio and Illinois, with 13,550 miles of pipelines and integrated storage fields.

Cash and Cash Equivalents

Cash equivalents are highly liquid investments with an original maturity of three months or less. Cash equivalents are stated at cost plus accrued interest, which approximates fair value. Certain short-term investments, for example, those held overnight, result in significant cumulative inflows and outflows of cash. In accordance with SFAS No. 95, *Statement of Cash Flows*, the Partnership reflects these activities on a net basis in the Investing Activities section of the Consolidated Statements of Cash Flows. The Partnership had no restricted cash at December 31, 2007 and 2006.

Cash Management and Advances to Affiliates

The operating subsidiaries participate in a cash management program to the extent they are permitted under Federal Energy Regulatory Commission (FERC) regulations. Under the cash management program, depending on whether a participating subsidiary has short-term cash surpluses or cash requirements, Boardwalk Pipelines either provides cash to them or they provide cash to Boardwalk Pipelines. The Partnership also periodically pays for certain taxes on behalf of BPHC. The obligations to repay these amounts are represented by demand notes and are stated at historical carrying amounts. Interest income and expense is recognized on an accrual basis when collection is reasonably assured. The interest rate on intercompany demand notes is London Interbank Offered Rate (LIBOR) plus one percent and is adjusted every three months.

Inventories

Inventories consisting of materials and supplies are carried at the lower of average cost or market, less an allowance for obsolescence.

Gas in Storage and Gas Receivables/Payables

Both operating subsidiaries have underground gas in storage which is utilized for system management and operational balancing, as well as for certain tariff services including firm, interruptible and no-notice (NNS) storage and parking and lending (PAL) services. Certain of these volumes are a result of providing storage services which allow third parties to store their own natural gas in the pipelines' underground facilities.

The accompanying consolidated financial statements reflect the balance of underground gas in storage recorded at historical cost, as well as the resulting activity relating to the storage services and balancing activity. Gas stored underground includes natural gas volumes owned by the pipelines, at times reduced by certain operational encroachments upon that gas. Current gas stored underground represents retained fuel and excess working gas which is available for resale and is valued at the lower of weighted-average cost or market. Retained fuel is a component of Gulf South's tariff structure and is recognized as transportation revenue at market prices in the month of retention. Customers can pay Gulf South's fuel rate by physically delivering gas or making a cash payment.

In the course of providing transportation and storage services to customers, the pipelines may receive different quantities of gas from shippers and operators than the quantities delivered on behalf of those shippers and operators. This results in transportation and exchange gas receivables and payables, commonly known as imbalances, which are primarily settled through the receipt or delivery of gas in the future or with cash. Settlement of imbalances requires agreement between the pipelines and shippers or operators as to allocations of volumes to specific transportation contracts and timing of delivery of gas based on operational conditions. For Gulf South, these receivables and payables are valued at market price. For Texas Gas, these amounts are valued at the historical value of gas in storage, consistent with the regulatory treatment and the settlement history.

Due to the method of storage accounting elected by Gulf South, the Partnership does not reflect volumes held by Gulf South on behalf of others on its Consolidated Balance Sheets. As of December 31, 2007 and 2006, Gulf South held 52.0 trillion British thermal units (TBtu) and 61.0 TBtu of gas owned by shippers, and had loaned 0.2 TBtu of gas to shippers as of December 31, 2007. No gas was loaned by Gulf South to shippers as of December 31, 2006. Consistent with the method of storage accounting elected by Texas Gas and the risk-of-loss provisions included in its tariff, Texas Gas reflects an equal and offsetting receivable and payable for customer-owned gas in its facilities for storage and related services. The amount reflected in Gas Payables on the Consolidated Balance Sheets is valued at a historical cost of gas of $36.6 million and $45.7 million at December 31, 2007 and 2006.

Derivative Financial Instruments

Subsidiaries of the Partnership use futures, swaps, and option contracts (collectively, derivatives) to hedge exposure to various risks, including natural gas commodity and interest rate risk. These hedge contracts are reported at fair value in accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended. The effective portion of the related unrealized gains and losses resulting from changes in fair values of the derivatives contracts designated as cash flow hedges are deferred as a component of Accumulated other comprehensive income. The deferred gains and losses are recognized in the Consolidated Statements of Income when the hedged anticipated transactions affect earnings. Changes in fair value of derivatives that are not designated as cash flow hedges in accordance with SFAS No. 133 are recognized in earnings in the periods that those changes in fair value occur. Note 8 contains more information regarding the Partnership's derivative financial instruments.

Property, Plant and Equipment

Property, plant and equipment (PPE) is recorded at its original cost of construction or fair value of assets purchased. Construction costs and expenditures for major renewals and improvements, which extend the lives of the respective assets, are capitalized. Construction work in progress is included in the financial statements as a component of PPE.

Gulf South depreciates assets using the straight-line method of depreciation over the estimated useful lives of the assets, which range from 3 to 35 years. The ordinary sale or retirement of property in the Gulf South system could result in a gain or loss. Depreciation at Texas Gas is provided primarily on the straight-line method at FERC-prescribed rates over estimated useful lives of 5 to 62 years. Reflecting the application of composite depreciation, gains and losses from the ordinary sale and retirement of PPE for Texas Gas generally do not impact PPE, net.

The Partnership evaluates long-lived assets for impairment when, in management's judgment, events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. When such a determination has been made, management's estimate of undiscounted future cash flows attributable to the assets is compared to the carrying value of the assets to determine whether an impairment has occurred. If an impairment of the carrying value has occurred, the amount of impairment recognized in the consolidated financial statements is determined by estimating the fair value of the assets and recording a loss for the amount that the carrying value exceeds the estimated fair value. Note 4 contains more information regarding the Partnership's PPE.

Goodwill

SFAS No. 142, *Goodwill and Other Intangible Assets*, requires an evaluation of goodwill for impairment at least annually or more frequently if events and circumstances indicate that the asset might be impaired. The impairment test for goodwill is performed annually at December 31. No impairment of goodwill was recorded during 2007, 2006 or 2005.

Regulatory Accounting

The operating subsidiaries are regulated by FERC. SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation*, requires that rate-regulated entities that meet certain specified criteria account for and report assets and liabilities consistent with the economic effect of the manner in which independent third-party regulators establish rates. Gulf South does not apply SFAS No. 71. Certain services provided by Gulf South are market-based and competition in its market area has often resulted in discounts from the maximum allowable cost-based rates being granted to customers, such that SFAS No. 71 has not been appropriate. Therefore, Gulf South does not record any regulatory assets or liabilities. Texas Gas applies SFAS No. 71. Therefore, certain costs and benefits are recorded as regulatory assets and liabilities based on expected recovery from customers or refund to customers in future periods.

The Partnership monitors the regulatory and competitive environment in which it operates to determine that the regulatory assets continue to be probable of recovery. If the Partnership were to determine that all or a portion of these regulatory assets no longer met the criteria for recognition as regulatory assets under SFAS No. 71, that portion which was not recoverable would be written off, net of any regulatory liabilities. Note 6 contains more information regarding the Partnership's regulatory assets and liabilities.

Acquired Executory Contracts

As a result of the Gulf South acquisition in December 2004, the Partnership recorded certain shipper contracts at fair value. The below-market valuation balance of $0.2 million and $1.3 million as of December 31, 2007 and 2006 was included as a component of Other current liabilities At the date of acquisition, these deferred credits were to be amortized over the life of the shipper contracts ranging from three months to three years. Amortization for 2007, 2006 and 2005 was $1.1 million, $4.0 million and $9.6 million and is expected to be $0.2 million for 2008.

Asset Retirement Obligations

SFAS No. 143, *Accounting for Asset Retirement Obligations*, addresses accounting and reporting for existing legal obligations associated with the future retirement of long-lived assets. SFAS No. 143 requires entities to record the fair value of a liability for an asset retirement obligation (ARO) in the period during which the liability is incurred. The liability is initially recognized at fair value and is increased with the passage of time as accretion expense is recorded, until the liability is ultimately settled. Corresponding retirement costs are capitalized as part of the carrying amount of the related long-lived asset and depreciated over the useful life of the asset. Note 5 contains more information regarding the Partnership's asset retirement obligations.

Unit-Based Compensation

The Partnership provides awards of phantom units to certain employees under its Long Term Incentive Plan and Strategic Long Term Incentive Plan. Pursuant to SFAS No. 123(R), *Share-Based Payment,* the Partnership measures the cost of an award issued in exchange for employee services based on the grant-date fair value of the award, which is remeasured each reporting period until settlement, and recognizes it as compensation expense over the period the employee is required to provide service in exchange for the award, usually the vesting period. To the extent forfeitures of awards occur during a period due to employee terminations, cumulative compensation expense previously recognized is reversed in the period of forfeiture. Note 9 contains additional information regarding the Partnership's unit-based compensation.

Revenue Recognition

The maximum rates that may be charged by the operating subsidiaries for their gas transportation and storage services are established through the FERC cost-based rate-making process. Rates charged by the operating subsidiaries may be less than those allowed by the FERC. Revenues from the transportation of gas are recognized in the period the service is provided based on contractual terms and the related volumes transported. Revenues from storage services are recognized over the term of the contracts. In connection with certain PAL agreements, cash is received at inception of the service period resulting in the recording of deferred revenues which are recognized in revenues over the period the services are provided. The Partnership had deferred revenues of $7.2 million at December 31, 2007, related to PAL services to be provided mainly in 2008. At December 31, 2006, the Partnership had deferred revenues of $22.4 million.

Retained fuel is a component of Gulf South's tariff structure and is recognized in revenues at market prices in the month of retention. The related fuel consumed in providing transportation services is recorded as a component of Operation and maintenance expense at market prices in the month consumed. Customers may elect to pay cash for fuel, instead of having fuel retained in-kind. Transportation revenues recognized from retained fuel for the years ended December 31, 2007, 2006 and 2005 were $73.0 million, $73.2 million and $86.7 million.

Under the FERC's regulations, certain revenues that the operating subsidiaries collect may be subject to possible refunds to their customers. Accordingly, during a rate case, estimates of rate refund reserves are recorded considering regulatory proceedings, advice of counsel and estimated risk-adjusted total exposure, as well as other factors. At December 31, 2007 and 2006, there were no liabilities for any open rate case recorded on the Consolidated Balance Sheets. Currently, neither of the operating subsidiaries is involved in an open general rate case.

Trade and Other Receivables

Trade and other receivables are stated at the historical carrying amount, net of allowances for doubtful accounts or write-offs. The Partnership establishes an allowance for doubtful accounts on a case-by-case basis when it believes the required payment of specific amounts owed is unlikely to occur. Uncollectible receivables are written off when a settlement is reached for an amount that is less than the outstanding historical balance or a receivable amount is deemed otherwise unrealizable.

Repair and Maintenance Costs

The operating subsidiaries account for repair and maintenance costs in accordance with FERC regulations, which is consistent with GAAP. FERC identifies installation, construction and replacement costs that are to be capitalized. All other costs are expensed as incurred.

Capitalized Interest and Allowance for Funds Used During Construction (AFUDC)

Capitalized interest represents the cost of borrowed funds used to finance construction activities. The Partnership records capitalized interest in connection with Gulf South construction activities. AFUDC represents the cost of funds, including equity funds, applicable to the regulated natural gas transmission plant under construction as permitted by FERC regulatory practices. In accordance with SFAS No. 71, the Partnership records AFUDC in connection with Texas Gas construction activities. Capitalized interest and the allowance for borrowed funds used during construction are recognized as a reduction to Interest expense and the allowance for equity funds used during construction is included in Miscellaneous other income within the Consolidated Statements of Income. The following table summarizes capitalized interest and the allowance for borrowed funds and allowance for equity funds used during construction (in millions):

	For the Year Ended December 31,		
	2007	**2006**	**2005**
Capitalized interest and allowance for borrowed funds used during construction	$ 27.1	$ 2.3	$ 0.7
Allowance for equity funds used during construction	3.0	1.2	1.4

Partner Capital Accounts

For purposes of maintaining the capital accounts, items of income and loss of the Partnership are allocated among the partners in each taxable year, or portion thereof in accordance with the partnership agreement. Generally, net income for each period is allocated among the partners based on their respective ownership interests after deducting any priority allocations in the form of cash distributions paid to the general partner as the holder of incentive distribution rights.

Income Taxes

The Partnership is not a taxable entity for federal income tax purposes. As such, it does not directly pay federal income tax. The Partnership's taxable income or loss, which may vary substantially from the net income or loss reported in the Consolidated Statements of Income, is includable in the federal income tax returns of each partner. The aggregate difference in the basis of the Partnership's net assets for financial and income tax purposes cannot be readily determined as the Partnership does not have access to the information about each partner's tax attributes related to the Partnership. The subsidiaries of the Partnership directly incur some income-based state taxes which are presented in Income taxes and charge-in-lieu of income taxes on the Consolidated Statements of Income. Note 11 contains more information regarding the Partnership's income taxes.

Reclassifications

Certain reclassifications have been made to the 2006 and 2005 financial statements to conform to the 2007 presentation, primarily related to individual amounts and captions within the Operating Activities section of the Consolidated Statements of Cash Flows.

Note 3: Commitments and Contingencies

Calpine Energy Services (Calpine) Settlement

In 2002 and 2003, Calpine entered into two 20-year transportation agreements with Gulf South. In December 2005, Calpine filed for Chapter 11 Bankruptcy protection and in early 2006 discontinued making payments on one of the transportation agreements. Gulf South continued to invoice Calpine under the transportation agreements and fully reserved the revenues associated with the contract on which Calpine was not making payments. In December 2007, Gulf South and Calpine filed a stipulation and agreement with the Bankruptcy court, which was approved in January 2008, to terminate the firm transportation agreement on which Calpine was delinquent, and to settle all of Gulf South's claims in the Bankruptcy proceedings for approximately $16.5 million. The claim was to be paid in the form of Calpine stock, along with other general creditors having claims in the Bankruptcy proceeding. In January 2008, Boardwalk sold the Bankruptcy claim to a third party and received a cash payment of approximately $15.3 million. The assignment is with recourse subject to the issuance of Calpine stock in the full amount of the claim. As a result of the settlement, in 2007 Boardwalk recognized $4.1 million in Gas transportation revenues related to invoiced amounts past due, which were previously reserved. The remainder of the settlement amount will be recognized upon full payment of the settlement amount by Calpine.

Jackson Storage Gas Loss

The Partnership's Jackson, Mississippi aquifer storage facility has a working gas capacity of approximately 5.0 billion cubic feet (Bcf) and is primarily used for operational purposes. In the fourth quarter 2007, it was determined that, based upon tests used to estimate the amount of gas stored in the facility, gas loss had occurred in the range of 1.3 to 1.7 Bcf. As a result of the estimated gas loss, the Partnership recognized a charge of $0.7 million to Operation and maintenance expense in the fourth quarter 2007. This amount was determined by applying the carrying value of gas in the facility of $0.53 per million British thermal units (MMBtu), to the low end of the range of estimated gas loss of 1.3 Bcf. An assessment is underway to determine whether the gas will need to be replaced in order to operate the facility and support pipeline operations. A more comprehensive test of the field will be performed in the second quarter 2008. If the pending test results indicate that the actual gas loss is greater than the estimated 1.3 Bcf, this could result in a future adjustment to the estimate.

Impact of Hurricanes Katrina and Rita

In August and September 2005, Hurricanes Katrina and Rita (hurricanes), and related storm activity caused extensive and catastrophic physical damage to the offshore, coastal and inland areas in the Gulf Coast region of the United States. A substantial portion of the Partnership's assets are located in the area directly impacted by the hurricanes. The remediation work related to the hurricanes was completed in 2007.

The Partnership reduced its liability for estimated costs associated with the hurricanes by $0.4 million in 2007 and increased the liability by $0.1 million in 2006. The Partnership recorded charges related to the hurricanes of $12.9 million in 2005, $2.0 million of which was recorded to Operating revenues and $10.9 million of which was recorded to Operating costs and expenses. The accrued liability for the hurricanes was zero at December 31, 2007, and $1.0 million at December 31, 2006.

In the third quarter 2007, the Partnership accrued estimated insurance proceeds of $5.1 million for claims related to Hurricane Rita which represented the minimum amount of insurance proceeds that were probable of recovery. This amount resulted in a reduction of Operating Costs and Expenses. In 2006, the Partnership recognized $10.7 million of insurance recoveries associated with Hurricane Katrina, $7.4 million of which was recorded to Operating Costs and Expenses and $3.3 million of which was recorded to Operating Revenues. The Partnership received a cash payment of $6.0 million in the fourth quarter 2006 and the remaining $4.7 million was recorded as a receivable at December 31, 2006. In the first quarter 2007, the Partnership received a final cash payment of $6.2 million of insurance proceeds related to damages incurred during Hurricane Katrina, $4.7 million of which was applied against the receivable and $1.5 million of which was recognized in Gas transportation revenues. Through December 31, 2007, the Partnership has received a total of approximately $12.2 million in insurance proceeds related to Hurricane Katrina, and will continue to pursue additional recovery of insurance proceeds related to Hurricane Rita.

Legal Proceedings

Napoleonville Salt Dome Matter

In December 2003, natural gas leaks were observed near two natural gas storage caverns that were being leased and operated by Gulf South for natural gas storage in Napoleonville, Louisiana. Gulf South commenced remediation efforts immediately and ceased using those storage caverns. Two class action lawsuits were filed relating to this incident and were converted to individual actions. Several individual actions have been filed against Gulf South and other defendants by local residents and businesses. In addition, the lessor of the property has filed an affirmative claim against Gulf South in an action filed against the lessor by one of Gulf South's insurers. Gulf South continues to vigorously defend each of these actions, however it is not possible to predict the outcome of this litigation as the cases remain in discovery. Litigation is subject to many uncertainties, and it is possible these actions could be decided unfavorably. Gulf South has settled many of the cases filed against it and may enter into discussions in an attempt to settle other cases if Gulf South believes it is appropriate to do so.

The remediation work related to the incident was completed in November 2006. Gulf South incurred $8.9 million for remediation costs, root cause investigation, and legal fees. Gulf South has made demand for reimbursement from its insurance carriers and will continue to pursue recoveries of the remaining expenses, including legal expenses. To date the insurance carriers have not taken any definitive coverage positions on all of the issues raised in the various lawsuits. During 2007, Gulf South has received $0.3 million of insurance reimbursements for legal expenses and root cause investigation.

Other Legal Matters

In connection with the acquisition of Texas Gas, The Williams Companies, Inc. (Williams) agreed to indemnify Boardwalk Pipelines for any liabilities or obligations in connection with certain litigation or potential litigation. Williams continues to defend the Partnership and Texas Gas and has retained responsibility for these claims. Therefore these claims are not expected to have a material effect upon the Partnership’s future financial condition, results of operations or cash flows.

The Partnership's subsidiaries are parties to various other legal actions arising in the normal course of business. Management believes the disposition of all known outstanding legal actions will not have a material adverse impact on the Partnership's financial condition, results of operations or cash flows.

Regulatory and Rate Matters

Pipeline Expansion Projects

East Texas to Mississippi Expansion. On June 18, 2007, the FERC granted the Partnership the authority to construct, own and operate a pipeline expansion consisting of approximately 242 miles of 42-inch pipeline from DeSoto Parish in western Louisiana to near Harrisville, Mississippi and approximately 110,000 horsepower of new compression having approximately 1.7 Bcf of new peak-day transmission capacity. Customers have contracted at fixed rates for 1.4 Bcf per day of firm transportation capacity on a long-term basis (with a weighted average term of approximately 6.8 years) from Carthage, Texas, which represents substantially all of the normal operating capacity. The pipeline facilities from Keatchie, Louisiana in DeSoto Parish to interconnects with Texas Gas near Bosco, Louisiana, and Columbia Gulf Transmission pipeline at Delhi, Louisiana began flowing gas on December 31, 2007. The remaining pipeline facilities from Delhi, Louisiana to Harrisville, Mississippi, began flowing gas during January 2008. Currently, the three compressor units at the Carthage compressor station are operational and the Partnership is making all of its primary firm contractual deliveries into the Delhi, Louisiana area and a substantial percentage of its primary firm contractual deliveries to markets in Mississippi. The Partnership is in the process of commissioning the remaining compression facilities associated with this project, which the Partnership expects to be completed during the second quarter 2008.

Gulf Crossing Project. The Partnership is pursuing construction of a new interstate pipeline that will begin near Sherman, Texas and proceed to the Perryville, Louisiana area. The project will be owned by Gulf Crossing, the Partnership's newly formed interstate pipeline subsidiary, and will consist of approximately 357 miles of 42-inch pipeline having up to approximately 1.7 Bcf of peak-day transmission capacity. Additionally, Gulf Crossing has entered into, subject to regulatory approval: (i) an operating lease for up to 1.4 Bcf per day of capacity on the Partnership's Gulf South pipeline system (including capacity on the Southeast Expansion and capacity on a portion of the East Texas to Mississippi Expansion) to make deliveries to an interconnect with Transcontinental Pipe Line Company (Transco) in Choctaw County, Alabama (Transco 85); and (ii) an operating lease with Enogex, a third-party intrastate pipeline, which will bring certain gas supplies to the Partnership's system. Customers have contracted at fixed rates for 1.1 Bcf per day of long-term firm transportation capacity (with a weighted average term of approximately 9.5 years). The certificate application for this project was filed with the FERC on June 19, 2007, and the Partnership expects this project to be in service by the first quarter 2009.

Southeast Expansion. On September 28, 2007, the FERC granted the Partnership the authority to construct, own and operate a pipeline expansion originating near Harrisville, Mississippi and extending to an interconnect with Transco 85. This expansion will initially consist of approximately 112 miles of 42-inch pipeline having approximately 1.2 Bcf of peak-day transmission capacity. To accommodate volumes expected to come from the Gulf Crossing leased capacity discussed above, this project will be expanded to 2.2 Bcf of peak-day transmission capacity. In addition, the FERC approved the Partnership's 260 million cubic feet (MMcf) per day operating lease with Destin Pipeline Company which will provide the Partnership enhanced access to markets in Florida. Customers have contracted at fixed rates for 660 MMcf per day of firm transportation capacity on a long-term basis (with a weighted-average term of 8.7 years), in addition to the capacity leased to Gulf Crossing discussed above. Construction has commenced and the Partnership expects this project to be in service during the second quarter 2008.

Fayetteville and Greenville Laterals. The Partnership is pursuing the construction of two laterals connected to its Texas Gas pipeline system to transport gas from the Fayetteville Shale area in Arkansas to markets directly and indirectly served by the Partnership's existing interstate pipelines. The Fayetteville Lateral will originate in Conway County, Arkansas and proceed southeast through the Bald Knob, Arkansas, area to an interconnect with the Texas Gas mainline in Coahoma County, Mississippi and consist of approximately 165 miles of 36-inch pipeline with an initial design of approximately 0.8 Bcf of peak-day transmission capacity. The Greenville Lateral will originate at the Texas Gas mainline near Greenville, Mississippi and proceed east to the Kosciusko, Mississippi, area consisting of approximately 95 miles of pipeline with an initial design capacity of approximately 0.8 Bcf of peak-day transmission capacity. The Greenville Lateral will allow customers to access additional markets, primarily in the Midwest, Northeast and Southeast. Customers have contracted at fixed rates for 575 MMcf per day of initial capacity, with options for additional capacity that, if exercised, could add 325 MMcf per day of capacity. The certificate application for this project was filed with the FERC on July 11, 2007. The Partnership expects the first 60 miles of the Fayetteville Lateral to be in service during the third quarter 2008 and the remainder of the Fayetteville and Greenville Laterals to be in service during the first quarter 2009.

Pipeline Expansion Project Costs and Timing. The total capital expenditures for the pipeline expansion projects through December 31, 2007 were $1.2 billion.

Storage Expansion Projects

Western Kentucky Storage Expansion Phase II. In December 2006, the FERC issued a certificate approving the Phase II storage expansion project which expanded the working gas capacity in the Partnership's western Kentucky storage complex by approximately 9.0 Bcf. This project is supported by binding commitments from customers to contract on a long-term basis (with a weighted-average term of 8.3 years) for the full additional capacity at the Texas Gas maximum applicable rate. The project was placed in service in November 2007.

Western Kentucky Storage Expansion Phase III. The Partnership has signed 10-year precedent agreements for 5.1 Bcf of storage capacity for its Phase III storage project. The certificate application for this project was filed with the FERC on June 25, 2007, seeking approval to develop up to 8.3 Bcf of new storage capacity if Texas Gas is granted market-based rate authority for the new storage capacity being proposed. The cost of this project will be dependent on the ultimate size of the expansion. The Partnership expects 5.4 Bcf of storage capacity to be in service in 2008.

Magnolia Storage Facility. The Partnership was developing a salt dome storage cavern near Napoleonville, Louisiana. Operational tests, which were completed in July 2007, indicated that due to geological and other anomalies that could not be corrected, the Partnership will be unable to place the cavern in service as expected. As a result, the Partnership has elected to abandon that cavern and is exploring the possibility of securing a new site on which a new cavern could be developed. In accordance with the requirements of SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets,* the carrying value of the cavern and related facilities of approximately $45.1 million was tested for recoverability. In the second quarter 2007, the Partnership recognized an impairment charge to earnings of approximately $14.7 million, representing the carrying value of the cavern, the fair value of which was determined to be zero based on discounted expected future cash flows. The charge was presented as Asset impairment on the Consolidated Statements of Income. The Partnership expects to use the other assets associated with the project, which include pipeline, compressors, and other equipment and facilities, in conjunction with a replacement storage cavern to be developed. If it is determined in the future that the assets cannot be used in conjunction with a new cavern, the Partnership may be required to record an additional impairment charge at the time that determination is made. Additional costs to abandon the impaired cavern may be incurred due to regulatory or contractual obligations, however the amounts are inestimable at this time.

Pipeline Integrity

The Partnership expenses all costs incurred in the development of its integrity management program, as defined by the Pipeline and Hazardous Materials Safety Administration (PHMSA), and the ongoing inspecting, testing and reporting on the condition of the pipeline system except costs incurred to replace segments of pipeline or install software or equipment which are capitalized to the extent they meet the requirements of the Partnership's capitalization policy for those types of expenditures. As of December 31, 2007, the Partnership has invested approximately $12.3 million to develop and implement integrity management program computer systems that allow it to dynamically assess various pipeline risks on an integrated basis. The Partnership has systematically used smart, in-line inspection tools to verify the integrity of certain of its pipelines.

Environmental and Safety Matters

The operating subsidiaries are subject to federal, state, and local environmental laws and regulations in connection with the operation and remediation of various operating sites. The Partnership accrues for environmental expenses resulting from existing conditions that relate to past operations when the costs are probable and can be reasonably estimated. In addition to federal and state mandated remediation requirements, the Partnership often enters into voluntary remediation programs with the agencies.

As of December 31, 2007 and 2006, the Partnership had an accrued liability of approximately $17.0 million and $18.4 million related to assessment and/or remediation costs associated with the historical use of polychlorinated biphenyls, petroleum hydrocarbons and mercury, enhancement of groundwater protection measures and other costs. The expenditures are expected to occur over approximately the next ten years. The accrual represents management's estimate of the undiscounted future obligations based on evaluations and discussions with counsel and operating personnel and the current facts and circumstances related to these matters. As of December 31, 2007 and 2006, approximately $2.7 million and $3.5 million were recorded in Other current liabilities. As of December 31, 2007 and 2006, approximately $14.3 million and $14.9 million were recorded in Other Liabilities and Deferred Credits.

On October 20, 2006, Texas Gas received notice from the Environmental Protection Agency (EPA) that Texas Gas is a potentially responsible party under the Comprehensive Environmental Response, Compensation, and Liability Act of 1980 with respect to the LWD, Inc. Superfund Site in Calvert City, Kentucky. The Partnership is unable to estimate with any certainty at this time any potential liability it may incur related to this notice but does not expect the outcome to have a material effect on its financial condition, results of operations or cash flows.

On November 2, 2005, Texas Gas received notice from the EPA that it has been identified as a *de minimis* settlement waste contributor at a Mercury Refining Superfund Site located at the Towns of Colonie and Guilderland, Albany County, New York. A *de minimis* party is one which sent less than 1.0% of the total mercury and/or mercury bearing materials to the site. As a *de minimis* party, Texas Gas was offered participation in a settlement agreement. The settlement amount for Texas Gas is approximately $0.1 million. The EPA held a 30-day public comment period regarding the settlement, but has not acted on it. In November 2007, Texas Gas received a notice from the EPA that it was withdrawing its settlement offer and would be issuing a new settlement offer in the future. Based upon the EPA's notice it appears that Texas Gas will still be considered a *de minimis* party, and it is not expected that the new settlement will have a material effect on our financial condition, results of operations or cash flows.

The Partnership's pipelines are subject to the Clean Air Act (CAA) and the CAA Amendments of 1990 (Amendments) which added significant provisions to the CAA. The Amendments require the EPA to promulgate new regulations pertaining to mobile sources, air toxins, areas of ozone non-attainment and acid rain. The Partnership presently operates two facilities in areas affected by non-attainment requirements for the current ozone standard (eight-hour standard). As of December 31, 2007, the Partnership had incurred costs of approximately $13.7 million for emission control modifications of compression equipment located at facilities required to comply with current CAA provisions, the Amendments and state implementation plans for nitrogen oxide reductions. These costs are being recorded as additions to PPE as the modifications are added. If the EPA designates additional new non-attainment areas or promulgates new air regulations where the Partnership operates, the cost of additions to PPE is expected to increase, however the Partnership is unable at this time to estimate with any certainty the cost of any additions that may be required.

In June 2007, the EPA proposed to lower the 8-hour ozone standard relevant to non-attainment areas. If adopted, new non-attainment areas will likely be identified which may require additional emission controls for compliance at as many as 14 facilities operated by the Partnership. The anticipated effective date for compliance with the proposed standard if adopted in its current state, is between 2013 and 2016.

In addition, the EPA and the State of Texas promulgated new rules regarding hazardous air pollutants which required additional controls or equipment modifications at seven Partnership facilities. The Partnership has substantially complied and has incurred costs of $2.6 million at these facilities.

The Partnership has assessed the impact of the CAA on its facilities and does not believe compliance with these regulations will have a material impact on the results of continuing operations or cash flows.

The Partnership considers environmental assessment, remediation costs and costs associated with compliance with environmental standards to be recoverable through base rates, as they are prudent costs incurred in the ordinary course of business and, therefore, no regulatory asset has been recorded to defer these costs. The actual costs incurred will depend on the actual amount and extent of contamination discovered, the final cleanup standards mandated by the EPA or other governmental authorities and other factors.

For further discussion of the Partnership's environmental exposure included in the calculation of its asset retirement obligations, see Note 5 of these Notes to Consolidated Financial Statements.

Lease Commitments

The Partnership has various operating lease commitments extending through the year 2018 generally covering offices and equipment. Total lease expenses for the years ended December 31, 2007, 2006 and 2005 were approximately $7.3 million, $4.7 million and $4.2 million. The following table summarizes minimum future commitments related to these items at December 31, 2007 (in millions):

2008	$	6.7
2009		5.5
2010		5.3
2011		3.0
2012		3.0
Thereafter		13.2
Total	$	36.7

Commitments for Construction

The Partnership incurred $1.2 billion of capital expenditures in 2007. The Partnership's future capital commitments as of December 31, 2007, for contracts already authorized are expected to approximate the following amounts (in millions):

Less than 1 year	$	834.7
1-3 years		16.4
4-5 years		-
More than 5 years		-
Total	$	851.1

Note 4: Property, Plant and Equipment

On December 31, 2007, the Partnership placed in service a portion of its East Texas to Mississippi expansion project from Keatchie, Louisiana in DeSoto Parish to its interconnects with Texas Gas near Bosco, Louisiana and Columbia Gulf Transmission pipeline at Delhi, Louisiana. As a result, approximately $476.0 million was transferred from construction work in progress to depreciable PPE. The assets will generally be depreciated over a term of 35 years. The remaining pipeline to Harrisville, Mississippi was placed in service during January 2008 and the related compression at one of the three compressor stations went in service in January and February 2008.

In November 2007, the Partnership placed in service Phase II of its Western Kentucky storage expansion project which increased the working gas capacity of its Texas Gas system by 9.0 Bcf, resulting in reclassification of approximately $50.0 million from construction work in progress to depreciable PPE. As a result of the expansion, approximately 4.0 Bcf of base gas was sold in 2007, resulting in a total gain of $22.0 million including gains on the settlement of related derivatives.

In conjunction with a review of its offshore pipeline assets in the South Timbalier Bay area, offshore Louisiana, the Partnership discovered that approximately 6 to 7 miles of offshore pipeline did not have adequate cover. In 2007, the Partnership entered into an agreement to sell for a nominal amount the offshore pipeline assets in their current condition and recognized an impairment charge of approximately $4.5 million representing the net book value of the assets. In accordance with the agreement, the Partnership paid the buyer approximately $4.8 million primarily to settle the liability to re-cover the pipeline and other maintenance issues. The total charge for 2007 related to the remediation payment and impairment charge was $9.3 million, $4.8 million of which was recorded to Operation and maintenance expense and the remainder to Asset impairment. The Partnership expects the sale to be completed in 2008.

In 2006, the Partnership received $4.0 million in settlement of a lawsuit concerning the parties' rights and obligations under a lease for a platform being decommissioned in the Eugene Island area in the Gulf of Mexico. The proceeds were used to offset the costs of rebuilding certain offshore facilities. Also, in 2006, the Partnership received $2.5 million for the sale of offshore transmission facilities in the Gulf of Mexico at West Cameron 294. The sale of the facilities was considered a normal retirement. In accordance with the composite method of accounting for PPE, the proceeds and the related book value of the plant were recorded to accumulated depreciation which is classified within PPE, net on the Consolidated Balance Sheets.

The following table presents the Partnership's PPE as of December 31, 2007 and 2006 (in thousands):

Category	**2007 Class Amount**	**Weighted-Average Useful Lives (Years)**	**2006 Class Amount**	**Weighted-Average Useful Lives (Years)**
Depreciable plant:				
Intangible	$ 24,897	9	$ 18,901	9
Gathering	92,828	19	90,787	19
Storage	198,110	49	163,323	48
Transmission	2,125,864	43	1,601,064	45
General	79,605	15	63,698	16
Total utility depreciable plant	2,521,304	41	1,937,773	43
Non-depreciable:				
Land	9,643		9,386	
Storage	71,182		85,392	
Construction work in progress	951,433		165,916	
Other	14,326		13,381	
Total other	1,046,584		274,075	
Total PPE	3,567,888		2,211,848	
Less: accumulated depreciation	262,477		187,412	
Total PPE, net	$ 3,305,411		$ 2,024,436	

The non-transmission assets have weighted-average useful lives of 33 years and 32 years as of December 31, 2007 and 2006 and depreciable asset values of $395.4 million and $336.7 million as of December 31, 2007 and 2006. The non-depreciable assets and construction work in progress were not included in the calculation of the weighted-average useful lives.

The Partnership holds undivided interests in certain assets, particularly the Bistineau storage facility of which the Partnership owns 91.7%, the Mobile Bay Pipeline of which the Partnership owns 50.0%, offshore pipeline assets, onshore pipeline and gathering assets, in each of which the Partnership holds various ownership interests. The proportionate share of investment associated with these interests has been recorded as PPE on the Consolidated Balance Sheets. The Partnership records its portion of direct operating expenses associated with the assets in Operation and maintenance expense. As of December 31, 2007, the gross investment in PPE related to these assets was $87.5 million, approximately $57.0 million, $12.8 million and $11.2 million of which was due to the Bistineau storage, offshore assets and Mobile Bay Pipeline interests. The accumulated depreciation was $17.4 million, approximately $5.0 million, $10.4 million and $1.0 million of which was due to the Bistineau storage, offshore assets and Mobile Bay Pipeline interests.

Note 5: Asset Retirement Obligations

The Partnership has identified and recorded legal obligations associated with the abandonment of offshore pipeline laterals and certain onshore facilities as well as abatement of asbestos when removed from certain compressor stations and meter station buildings. Pursuant to federal regulations, the Partnership has a legal obligation to cut and purge any pipeline that will remain in place after abandonment and to remove offshore platforms after the related gas flows have ceased. Abatement of asbestos consists of removal, transportation and disposal. Legal obligations exist for certain other Partnership assets; however, the fair value of the obligations cannot be determined because the end of the system life is potentially indefinite and therefore cannot be estimated with the degree of accuracy necessary to establish a liability for the obligations.

The following table summarizes the aggregate carrying amount of AROs (in thousands):

	2007	2006
Balance at beginning of year	$ 14,307	$ 14,074
Liabilities recorded	1,529	(366)
Liabilities settled	(499)	-
Accretion expense	722	599
Balance at end of year	$ 16,059	$ 14,307

The Financial Accounting Standards Board (FASB) Interpretation No. 47, *Accounting for Conditional AROs,* clarifies when an entity is required to recognize a liability for the fair value of a conditional ARO. In light of this interpretation, the Partnership believes that an ARO exists for the Texas Gas corporate office building constructed in Owensboro, Kentucky, in 1962. Under the legal requirements enacted by the EPA during 1973, Texas Gas became legally obligated to dismantle and remove the asbestos from its corporate office at the end of its useful life, estimated to be within a range of years between 2112 through 2162. The Partnership believes that the spray-applied asbestos can be maintained, in place, undisturbed, indefinitely, by following written maintenance procedures. The Partnership believes that the fair value of any liability relating to future remediation is not material to its financial position, results of operations or cash flows and that any costs incurred for this remediation would be recoverable in its rates.

Depreciation rates for utility plant at Texas Gas, as approved by the FERC are comprised of two components: one based on economic service life (capital recovery) and one based on net costs of removal (negative salvage). Texas Gas accrues and collects in its rates estimated net costs of removal of long-lived assets through negative salvage expense, which does not represent an existing legal obligation. The Partnership has classified $42.4 million and $39.6 million as of December 31, 2007 and 2006, in the accompanying Consolidated Balance Sheets as Provision for other asset retirement.

Note 6: Regulatory Assets and Liabilities

The amounts recorded as regulatory assets and liabilities in the Consolidated Balance Sheets as of December 31, 2007 and 2006, are summarized in the table below. The table also includes amounts related to unamortized debt expense and unamortized discount on long-term debt. While these amounts are not regulatory assets and liabilities as defined by SFAS No. 71, they are a critical component of the embedded cost of debt financing utilized in the Texas Gas rate proceedings. The tax effect of the equity component of AFUDC represents amounts recoverable from rate payers for the tax effects created prior to the change in Boardwalk Pipelines' tax status. Certain amounts in the table are reflected as a negative, or a reduction, to be consistent with the manner in which Texas Gas records these items in its regulatory books of account. None of the regulatory assets shown below were earning a return as of December 31, 2007 and 2006 (in thousands):

	2007	2006
Regulatory Assets:		
Pension	$ 9,490	$ 7,820
Tax effect of AFUDC equity	6,381	6,794
Unamortized debt expense and premium on reacquired debt	10,705	11,703
Postretirement benefits other than pension	5,414	10,569
Fuel tracker	943	5,783
Imbalances/storage valuation tracker	-	37
Total regulatory assets	$ 32,933	$ 42,706
Regulatory Liabilities:		
System management/cashout tracker	$ 242	-
Provision for asset retirement	42,380	$ 39,644
Unamortized discount on long-term debt	(1,677)	(1,851)
Postretirement benefits other than pension	12,448	-
Total regulatory liabilities	$ 53,393	$ 37,793

Note 7: Financing

Offerings of Common Units

In addition to its IPO in November 2005, the Partnership has completed three follow-on public equity offerings. The proceeds of the follow-on offerings have been and will be used to finance the Partnership's expansion activities discussed in Note 3. In addition to funds received from the public, the general partner has concurrently contributed amounts to maintain its 2.0% interest in the Partnership. The following table shows the key information related to the follow-on public equity offerings (in millions, except the offering price):

Month of Offering	Number of Common Units	Offering Price	Less Underwriting Discounts and Expenses	Net Proceeds (including General Partner Contribution)	Common Units Outstanding After Offering	Common Units Held by the Public After Offering
November 2007	7.5	$ 30.90	$ 3.7	$ 232.8	90.7	37.4
March 2007	8.0	36.50	4.2	293.8	83.2	29.9
November 2006	6.9	29.65	9.4	199.4	75.2	21.9

The Partnership completed its IPO in November 2005, resulting in net proceeds of approximately $271.4 million. After the IPO, the Partnership had 68.3 million common units issued and outstanding, of which 15.0 million were held by the public. In connection with the IPO, the Partnership and its affiliates effected a number of transactions, including among others:

- the distribution by Boardwalk Pipelines of $126.4 million of cash, receivables and other working capital assets to BPHC;
- the contribution, directly and indirectly, by BPHC of all the equity interests of Boardwalk Pipelines to the Partnership;
- the Partnership's reimbursement to BPHC for $42.1 million of capital expenditures it incurred in connection with the acquisition of Gulf South;
- the assumption by the Partnership of $250.0 million of indebtedness to Loews from BPHC;
- the issuance by the Partnership of limited partner interest in the Partnership to BPHC; and
- the issuance by the Partnership of a 2.0% general partner interest and all of its incentive distribution rights to Boardwalk GP.

Senior Unsecured Debt

On August 17, 2007, the Partnership received net proceeds of approximately $495.3 million after deducting initial purchaser discounts and offering expenses of $4.7 million from the sale of $225.0 million of 5.75% senior unsecured notes of Gulf South due August 15, 2012, and $275.0 million of 6.30% senior unsecured notes of Gulf South due August 15, 2017. Interest on the notes will be payable on February 15 and August 15 of each year, beginning on February 15, 2008.

On November 21, 2006, Boardwalk Pipelines received net proceeds of approximately $248.3 million after deducting underwriting discounts and commissions and offering expenses of $1.7 million from its offering of $250.0 million of 5.88% senior unsecured notes, which are guaranteed by the Partnership. Interest on the notes will be payable on May 15 and November 15 of each year, beginning on May 15, 2007. The notes will mature on November 15, 2016.

The Gulf South and Boardwalk Pipelines notes are redeemable, in whole or in part, at the Partnership's option at any time, at a redemption price equal to the greater of 100.0% of the principal amount of the notes to be redeemed or a "make whole" redemption price based on the remaining scheduled payments of principal and interest discounted to the date of redemption at a Treasury rate plus 20 basis points in the case of the 2012 Gulf South notes and 2016 Boardwalk Pipelines notes, or 25 basis points in the case of the 2017 Gulf South notes, plus accrued and unpaid interest, if any. Other customary covenants apply, including those concerning events of default.

The following table represents all long-term debt issues outstanding (in thousands):

	December 31, 2007	December 31, 2006
Boardwalk Pipelines		
5.88% Notes due 2016	$ 250,000	$ 250,000
5.20% Notes due 2018	185,000	185,000
5.50% Notes due 2017	300,000	300,000
Gulf South		
6.30% Notes due 2017	275,000	-
5.75% Notes due 2012	225,000	-
5.05% Notes due 2015	275,000	275,000
Texas Gas		
7.25% Debentures due 2027	100,000	100,000
4.60% Notes due 2015	250,000	250,000
	1,860,000	1,360,000
Unamortized debt discount	(12,086)	(9,080)
Total long-term debt	$ 1,847,914	$ 1,350,920

As of December 31, 2007 and 2006, the weighted-average interest rate of the Partnership's long-term debt was 5.82% and 5.40%.

The long-term debt has restrictive covenants which provide that, with certain exceptions, neither the Partnership nor any of its subsidiaries may create, assume or suffer to exist any lien upon any property to secure any indebtedness unless the debentures and notes shall be equally and ratably secured. The Partnership relies on distributions and advances from the operating subsidiaries to fulfill its debt obligations. All debt obligations are unsecured. At December 31, 2007, Boardwalk Pipelines and the operating subsidiaries were in compliance with their debt covenants.

Revolving Credit Facility

The Partnership maintains a $1.0 billion revolving credit facility, which was increased from $700.0 million in November 2007, under which Boardwalk Pipelines, Gulf South and Texas Gas each may borrow funds, up to applicable sub-limits. Interest on amounts drawn under the credit facility is payable at a floating rate equal to an applicable spread per annum over LIBOR or a base rate defined as the greater of the prime rate or the Federal funds rate plus 50 basis points. Under the terms of the agreement, each of the borrowers must maintain a minimum ratio, as of the last day of each fiscal quarter, of consolidated total debt to consolidated earnings before interest, income taxes and depreciation and amortization (as defined in the agreement), measured for the preceding twelve months, of not more than five to one. The revolving credit facility has a maturity date of June 29, 2012.

As of December 31, 2007, no funds were drawn under the facility, however, the Partnership had outstanding letters of credit under the facility for $185.6 million to support certain obligations associated with the Fayetteville and Greenville Lateral and Gulf Crossing expansion projects which reduced the available capacity under the facility by such amount. As of December 31, 2007, the Partnership was in compliance with all the covenant requirements under the credit agreement. During 2006, the Partnership had borrowed and repaid $90.0 million under this credit facility. The interest rates on the borrowings were 5.55% to 5.73%.

Note 8: Derivatives

Subsidiaries of the Partnership use futures, swaps, and option contracts (collectively, derivatives) to hedge exposure to various risks, including natural gas commodity price risk and interest rate risk. These hedge contracts are reported at fair value in accordance with SFAS No. 133.

Certain volumes of gas stored underground are available for sale and subject to commodity price risk. At December 31, 2007 and December 31, 2006, approximately $16.3 million and $14.0 million of gas stored underground, which the Partnership owns and carries on its Consolidated Balance Sheets as current Gas stored underground, was exposed to commodity price risk. The Partnership utilizes derivatives to hedge certain exposures to market price fluctuations on the anticipated operational sales of gas.

As a result of the approval of Phase II of the Western Kentucky storage expansion project, approximately 4.8 Bcf of gas stored underground with a book value of $11.3 million became available for sale, although it was subsequently determined that 0.8 Bcf of the gas would be used for line pack for the Partnership’s Fayetteville and Greenville Lateral expansion project. The Partnership entered into derivatives to hedge the price exposure related to 3.0 Bcf of the storage gas sold under forward sales agreements, which were designated as cash flow hedges during February 2007, concurrent with the designation of the forward sales agreements as normal sales. The derivatives were settled in March 2007, when the sales price was determined. The Partnership entered into derivatives related to the remaining 1.0 Bcf of storage gas available for sale which were not designated as cash flow hedges and have been marked to fair value through earnings. In the third and fourth quarters 2007, all of the storage gas available for sale was sold and the related derivatives were settled resulting in a gain of $22.0 million. The gain was included in Net gain on disposal of operating assets and related contracts on the Consolidated Statements of Income.

In the second quarter 2007, the Partnership entered into natural gas price swaps to hedge exposure to prices associated with the purchase of 2.1 Bcf of natural gas to be used for line pack for the Partnership’s Gulf Crossing and Southeast Expansion projects, approximately 1.3 Bcf of which remained outstanding at December 31, 2007. The derivatives were not designated as hedges and were marked to fair value through earnings resulting in a loss of $1.0 million for the year ended December 31, 2007.

In August 2007, the Partnership entered into a Treasury rate lock for a notional amount of $150.0 million of principal to hedge the risk attributable to changes in the risk-free component of forward 10-year interest rates through February 1, 2008. The reference rate on the rate lock was 4.74%. Under the terms of the rate lock, the counterparty would pay the Partnership a settlement amount if the 10-year Treasury rate is greater than the reference rate on February 1, 2008. Conversely, the Partnership would pay the counterparty a settlement amount if the 10-year Treasury rate is less than the reference rate. The Treasury rate lock was designated as a cash flow hedge in accordance with SFAS No. 133. As of December 31, 2007, the Partnership recorded a payable of $8.4 million and a corresponding amount in Accumulated other comprehensive income for the fair value of the rate lock. On February 1, 2008, the Partnership paid the counterparty approximately $15.0 million to settle the rate lock. The effective portion of the loss will be recognized in Interest expense over the term of the related debt to be issued.

In August 2006, the Partnership entered into Treasury rate locks with two counterparties each for a notional amount of $100.0 million of principal to hedge the risk attributable to changes in the risk-free component of forward 10-year interest rates through August 1, 2007. The reference rates on the rate locks were 5.00% and 4.96%. The rate locks were designated as cash flow hedges in accordance with SFAS No. 133. In August 2007, the rate locks were settled resulting in payments to the counterparties of approximately $3.9 million. The effective amount of the hedge, of approximately $3.4 million is being amortized to interest expense over the 10-year term of the related notes which were issued in August 2007.

With the exception of the derivatives related to storage gas volumes and line pack gas purchases referred to above, the derivatives related to the sale or purchase of natural gas, cash for fuel reimbursement and debt issuance generally qualify for cash flow hedge accounting under SFAS No. 133 and are designated as such. The effective component of related unrealized gains and losses resulting from changes in fair values of the derivatives contracts designated as cash flow hedges are deferred as a component of Accumulated other comprehensive income. The deferred gains and losses are recognized in the Consolidated Statements of Income when the anticipated transactions affect earnings. Generally, for gas sales and cash for fuel reimbursement, any gains and losses on the related derivatives would be recognized in Operating Revenues. For the sale of gas related to the Western Kentucky storage expansion project, any gains and losses on the related derivatives were recognized in Net gain on disposal of operating assets and related contracts. Any gains and losses on the derivatives related to the line pack gas purchases would be recognized in Miscellaneous other income, net.

The fair values of derivatives existing as of December 31, 2007 and 2006, were included in the following captions in the Consolidated Balance Sheets (in millions):

	December 31, 2007	**December 31, 2006**
Prepaid expenses and other current assets	$ 2.2	$ 13.7
Other current liabilities	9.4	5.1
Accumulated other comprehensive (loss) income	(8.9)	8.3

The changes in fair values of the derivatives designated as cash flow hedges are expected to, and do, have a high correlation to changes in value of the anticipated transactions. Each reporting period the Partnership measures the effectiveness of the cash flow hedge contracts. To the extent the changes in the fair values of the hedge contracts do not effectively offset the changes in the estimated cash flows of the anticipated transactions, the ineffective portion of the hedge contracts is currently recognized in earnings. If the anticipated transactions are deemed no longer probable to occur, hedge accounting would be terminated and changes in the fair values of the associated derivative financial instruments would be recognized currently in earnings. Ineffectiveness decreased Net income by $0.1 million for the year ended December 31, 2007 and increased Net income by $0.5 million for the year ended December 31, 2006. No ineffectiveness was recorded during 2005. The Partnership did not discontinue any cash flow hedges during the years ended December 31, 2007 and 2006.

Note 9: Employee Benefits

Retirement Plans

Texas Gas employees hired before November 1, 2006, are covered under a non-contributory, defined benefit pension plan. The Texas Gas Supplemental Retirement Plan (SRP) provides pension benefits for the portion of an eligible employee's pension benefit that becomes subject to compensation limitations under the Internal Revenue Code. Effective November 1, 2006, the defined benefit pension plan was closed to new participants and new employees will be provided benefits under a defined contribution money purchase plan. The Partnership uses a measurement date of December 31 for its benefits plans.

As a result of its rate case settlement in 2006, the Partnership is required to fund the amount of the Texas Gas annual net periodic pension cost, including a minimum of $3.0 million which is the amount included in rates. During 2006, the Partnership funded approximately $18.0 million to the Texas Gas retirement plan including approximately $11.4 million of additional funding that the Partnership elected to provide to immediately improve the funded status of the plan. Due to the additional funding, the Partnership was not required to fund any amount to the Texas Gas retirement plan in 2007 and does not expect to fund any amount in 2008. Through December 31, 2007, no funding has been provided for the SRP other than the payment of benefits under the plan, and the Partnership does not expect to fund this plan in the future until such time as benefits are paid.

The Partnership recognizes each year the actuarially determined amount of net periodic pension cost in expense, including a minimum amount of $3.0 million, in accordance with the rate case settlement. Texas Gas is permitted to seek future rate recovery for amounts of annual pension costs in excess of $6.0 million and is precluded from seeking future recovery of annual pension costs between $3.0 and $6.0 million. As a result, the Partnership would recognize a regulatory asset for amounts of annual pension cost in excess of $6.0 million and would reduce its regulatory asset to the extent that any amounts of annual pension cost are less than $3.0 million. Annual pension costs between $3.0 million and $6.0 million will be charged to expense.

Postretirement Benefits Other Than Pensions (PBOP)

Texas Gas provides postretirement medical benefits and life insurance to retired employees who were employed full time, hired prior to January 1, 1996, and have met certain other requirements. The Partnership contributed $0.9 million, $0.3 million and $3.9 million to the plan in 2007, 2006 and 2005. Due to plan changes regarding benefits available to current and future retirees described below, the PBOP plan is currently in an overfunded status, therefore the Partnership does not expect to make any contributions to the plan in 2008.

In May 2006, as part of an overall cost reduction program, Texas Gas announced to its employees and retirees a plan to make changes to its postretirement benefits plan beginning January 1, 2007. Under the amended plan, Texas Gas will cap its contributions toward medical benefit coverage for retirees younger than age 65 to the amount contributed for each retiree in 2006. For retirees age 65 and older, Texas Gas will cap its contribution at three times the 2006 amount. In addition, Texas Gas will no longer cover prescription drug costs for retirees age 65 and older. The changes resulted in an estimated reduction in the accumulated postretirement benefit obligation (APBO) of approximately $75.3 million. For the year ended December 31, 2006, the change resulted in a reduction to net periodic benefit cost of $9.0 million from the amount that would otherwise have been recognized.

Due to the Texas Gas rate case settlement in the first quarter 2006, the Partnership began to amortize the balance of its regulatory asset for PBOP of approximately $32.0 million on a straight-line basis over 5 to 6 years. Texas Gas is precluded from seeking future recovery of additional amounts for PBOP costs.

Early Retirement Incentive Program

In 2006, Texas Gas implemented an early retirement incentive program (ERIP) which was made available to approximately 240 non-executive employees age 52 and older with at least five years of service. Under the program, Texas Gas would provide eligible employees three additional years for purposes of age-based vesting under the postretirement medical plan and three additional years of pay credits under the pension plan.

In 2007, all of the approximately 100 employees who elected to participate in the program retired and the Partnership recognized a settlement charge of $4.5 million related to the program. The Partnership recognized a special termination benefit of approximately $6.0 million for pension and $0.9 million for PBOP in 2006.

Projected Benefit Obligation, Fair Value of Assets and Funded Status

The projected benefit obligation, fair value of assets, funded status and the amounts not yet recognized as components of net periodic pension and postretirement benefits cost for the retirement plans and PBOP at December 31, 2007 and 2006, were as follows (in thousands):

	Retirement Plans		PBOP	
	For the Year Ended December 31,		For the Year Ended December 31,	
	2007	2006	2007	2006
Change in benefit obligation:				
Benefit obligation at beginning of period	$ 136,886	$ 116,931	$ 65,341	$ 134,188
Service cost	3,929	4,432	608	1,319
Interest cost	6,599	6,695	3,274	5,147
Plan participants' contributions	-	-	828	1,509
Actuarial (gain) loss	(2,197)	6,326	(9,343)	4,902
Benefits paid	(575)	(3,576)	(4,083)	(7,633)
Retirement / PBOP plan amendment	3	73	-	(75,271)
Settlement	(36,141)	-	-	-
Special termination benefits (ERIP)	-	6,005	-	884
Retiree drug subsidy	-	-	309	296
Benefit obligation at end of period	$ 108,504	$ 136,886	$ 56,934	$ 65,341
Change in plan assets:				
Fair value of plan assets at beginning of period	$ 121,125	$ 96,193	$ 80,218	$ 79,462
Actual return on plan assets	6,489	10,468	6,381	6,539
Benefits paid	(575)	(3,576)	(4,082)	(7,633)
Company contributions	395	18,040	883	341
Plan participants' contributions	-	-	828	1,509
Settlement	(36,141)	-	-	-
Fair value of plan assets at end of period	$ 91,293	$ 121,125	$ 84,228	$ 80,218
Funded status	$ (17,211)	$ (15,761)	$ 27,294	$ 14,877
Items not yet recognized as components of net periodic cost:				
Prior service cost	$ 71	$ 73	$ (62,984)	$ (70,744)
Net actuarial loss	11,731	17,967	10,658	22,316
Total	$ 11,802	$ 18,040	$ (52,326)	$ (48,428)

The Partnership does not anticipate that any plan assets will be returned to the Partnership during 2008. At December 31, 2007 and 2006, the following aggregate information relates only to the underfunded retirement plan (in thousands):

	For the Year Ended December 31,	
	2007	2006
Projected benefit obligation	$ 108,504	$ 136,886
Accumulated benefit obligation	94,590	118,147
Fair value of plan assets	91,293	121,125

Components of Net Periodic Benefit Cost

Components of net periodic benefit cost for both the retirement plans and PBOP for the years ended December 31, 2007, 2006 and 2005 were the following (in thousands):

	Retirement Plans			PBOP		
	For the Year Ended December 31,			For the Year Ended December 31,		
	2007	2006	2005	2007	2006	2005
Service cost	$ 3,929	$ 4,432	$ 4,067	$ 608	$ 1,319	$ 2,076
Interest cost	6,599	6,695	6,283	3,274	5,147	7,222
Expected return on plan assets	(7,146)	(7,131)	(6,859)	(4,734)	(4,653)	(4,632)
Amortization of prior service credit	5	-	-	(7,760)	(4,527)	-
Amortization of unrecognized net loss	242	713	300	668	1,112	362
Settlement charge	4,454	-	-	-	-	-
Special termination benefit (ERIP)	-	6,005	-	-	884	-
Regulatory asset (increase) decrease	(1,669)	(3,979)	(3,713)	5,415	7,337	-
Net periodic pension expense	$ 6,414	$ 6,735	$ 78	$ (2,529)	$ 6,619	$ 5,028

The decrease in the regulatory asset for PBOP was due primarily to the amortization of costs incurred in prior years. The regulatory asset for the retirement plans was increased due to the accumulated cost for the year exceeding the expense cap established in the Texas Gas rate case settlement. In accordance with the rate case settlement, Texas Gas is permitted to seek future rate recovery for amounts of annual pension costs in excess of $6.0 million.

Estimated Future Benefit Payments

The following table shows benefit payments, which reflect expected future service, as appropriate, which are expected to be paid for both the retirement plans and PBOP (in thousands):

	Retirement Plans	PBOP
2008	$ 3,397	$ 4,693
2009	3,633	4,499
2010	5,783	4,294
2011	7,140	4,282
2012	9,391	4,116
2013-2017	67,556	19,997

Weighted –Average Assumptions

The Partnership's weighted-average asset allocations at December 31, 2007 and 2006, for both the qualified retirement plan and PBOP trusts by category were as follows:

	Retirement Plans		PBOP	
	December 31, 2007	**December 31, 2006**	**December 31, 2007**	**December 31, 2006**
Debt securities	45.5%	49.1%	40.4%	46.6%
Equity securities	22.7%	27.1%	22.1%	29.2%
Limited partnerships	13.3%	9.3%	25.2%	23.6%
Comingled funds	12.5%	9.4%	-	-
Cash, short-term investments and other	6.0%	5.1%	12.3%	0.6%
Total	100.0%	100.0%	100.0%	100.0%

The Partnership employs a total-return approach whereby a mix of equities and fixed income investments is used to maximize the long-term return of plan assets for a prudent level of risk. The intent of this strategy is to minimize plan expenses by outperforming plan liabilities over the long run. Risk tolerance is established through careful consideration of the plan liabilities, plan funded status and the financial conditions of the Partnership. The Partnership's goal for 2007 was to allocate between 30.0% and 50.0% of the investment portfolio to equity and alternative investments, including limited partnerships, with consideration given to market conditions and target asset returns. The portion of the portfolio not invested in equity and alternative investments was invested primarily in fixed income securities, comingled funds and the remainder in cash and short-term investments. The investment portfolio contains a diversified blend of U.S. and non-U.S. fixed income and equity investments. Alternative investments, including hedge funds, are used judiciously to enhance risk-adjusted long-term returns while improving portfolio diversification. Derivatives may be used to gain market exposure in an efficient and timely manner. Investment risk is measured and monitored on an ongoing basis through annual liability measurements, periodic asset/liability studies and quarterly investment portfolio reviews.

Weighted-average assumptions used to determine benefit obligations for the years ended December 31, 2007 and 2006 were the following:

	Retirement Plans		PBOP	
	For the Year Ended December 31,		**For the Year Ended December 31,**	
	2007	**2006**	**2007**	**2006**
Discount rate	6.00%	5.75%	6.00%	5.75%
Rate of compensation increase	4.00%	5.50%	-	-

Weighted-average assumptions used to determine net periodic benefit cost for the periods indicated were as follows:

	Retirement Plans			PBOP		
	For the Year Ended December 31,			**For the Year Ended December 31,**		
	2007	**2006**	**2005**	**2007**	**2006**	**2005**
Discount rate	5.94%	5.63%	5.88%	5.75%	5.63% to 5.75%	5.88%
Expected return on plan assets	7.50%	7.50%	7.50%	5.00% to 6.15%	5.00% to 6.15%	5.00% to 6.15%
Rate of compensation increase	5.50%	5.50%	5.50%	-	-	-

PBOP assumed health care cost trends

Assumed health care-cost-trend rates have a significant effect on the amounts reported for PBOP. A one-percentage-point change in assumed health care-cost-trend rates would have had the following effects on amounts reported for the year ended December 31, 2007 (in thousands):

Effect of 1% Increase:	**2007**
Benefit obligation at end of year	$ 1,212
Total of service and interest costs for year	81
Effect of 1% Decrease:	
Benefit obligation at end of year	$ (1,481)
Total of service and interest costs for year	(102)

For measurement purposes, at December 31, 2007, health care costs for the plans were assumed to increase 9.0% for 2008-2009 grading down to 5.0% in 0.5% annual increments for participants not eligible for Medicare and 10.0% grading down to 5.0% in 0.5% annual increments for participants eligible for Medicare. For December 31, 2006, measurement purposes, health care costs for the plans were assumed to increase 9.0% for 2007-2008, grading down to 5.0% in 0.5% annual increments for participants not eligible for Medicare and 10.5% grading down to 5.0% in 0.5% annual increments for participants eligible for Medicare.

Defined Contribution Plans

Texas Gas employees hired on or after November 1, 2006 and Gulf South employees are provided retirement benefits under a similar defined contribution money purchase plan. The operating subsidiaries also provide 401(k) plan benefits to their employees. Costs related to the Partnership's defined contribution plans were $5.3 million, $5.1 million and $3.9 million for the years ended December 31, 2007, 2006 and 2005.

Strategic Long Term Incentive Plan

In 2006, Boardwalk GP approved the Partnership's Strategic Long Term Incentive Plan (SLTIP). The SLTIP provides for the issuance of up to 500 phantom general partner units (Phantom GP Units) to selected employees of the Partnership and its subsidiaries. The Partnership believes that such awards better align the interests of the selected employees with those of the general partner and common unitholders. Each Phantom GP Unit entitles the holder thereof, upon vesting, to a lump sum cash payment in an amount determined by a formula based on cash distributions made by the Partnership to its general partner during the four quarters preceding the vesting date and the implied yield on the Partnership's common units, up to a maximum of $50,000 per unit.

A summary of the status of the Partnership's SLTIP as of December 31, 2007 and 2006, and changes during the years ended December 31, 2007 and 2006, is presented below:

	Phantom GP Units	**Total Fair Value (in thousands)**	**Weighted-Average Vesting Period (in years)**
Granted 7/15/2006 (a)	125	$ 3,398	3.5
Granted 12/20/2006 (a)	125	6,250	4.0
Outstanding @ 12/31/2006 (b)	250	12,500	3.5
Granted (a)	116	5,800	4.0
Forfeited	(5)	-	-
Outstanding @ 12/31/2007 (b)	361	18,050	3.0

(a) Represents fair value and weighted-average vesting period of awards at grant date.
(b) Represents fair value and remaining weighted-average vesting period of outstanding awards at the end of the period.

The fair value of the awards at the date of grant was based on the formula contained in the SLTIP and assumptions made regarding potential future cash distributions made to the general partner during the four quarters preceding the vesting date and the future implied yield on the Partnership's common units. The fair value of the awards will be recognized ratably over the vesting period and remeasured each quarter until settlement in accordance with the treatment of awards classified as liabilities prescribed in SFAS No. 123(R). The Partnership recorded $3.3 million and $0.8 million in Administrative and general expenses during 2007 and 2006 for the ratable recognition of the GP Phantom Unit awards fair value. The total estimated remaining unrecognized compensation expense related to the GP Phantom Units outstanding at December 31, 2007, of $13.9 million will be recognized over the average remaining vesting period of approximately 3.0 years. Approximately 139 Phantom GP Units were available for grant under the plan at December 31, 2007.

Long-Term Incentive Plan

In 2005, the Partnership adopted the Long-Term Incentive Plan (LTIP) for the officers and directors of its general partner and for selected employees of its subsidiaries. The Partnership believes that such awards better align the interests of the selected employees with those of the common unitholders. The Partnership has reserved 3,525,000 units for grants of units, restricted units, unit options and unit appreciation rights under the plan. The Partnership has granted phantom common units under the plan. Each such grant includes: a tandem grant of Distribution Equivalent Rights (DERs); vests 50.0% on the second anniversary of the grant date and 50.0% on the third anniversary of the grant date; and will be payable to the grantee in cash upon vesting in an amount equal to the sum of the fair market value of the units (as defined in the plan) that vest on the vesting date plus the vested amount then credited to the grantee's DER account, less applicable taxes. The fair value of the awards will be recognized ratably over the vesting period and remeasured each quarter until settlement based on the market price of the Partnership's common units and amounts credited under the DERs. The Partnership did not make any grants of units, restricted units, unit options and unit appreciation rights under the plan.

A summary of the status of the Partnership's LTIP as of December 31, 2007, 2006 and 2005, and changes during the years ended December 31, 2007 and 2006, is presented below:

	Phantom Common Units	Total Fair Value (in thousands)	Weighted-Average Vesting Period (in years)
Outstanding @ 12/31/2005 (a)	29,177	$ 525	2.3
Granted (b)	49,387	1,537	2.5
Forfeited	(3,479)	-	-
Outstanding @ 12/31/2006 (a)	75,085	2,413	2.2
Granted (b)	49,966	1,530	2.5
Vested (c)	(14,431)	-	-
Forfeited	(2,099)	-	-
Outstanding @ 12/31/2007 (a)	108,521	3,493	1.8

(a) Represents fair value and remaining weighted-average vesting period of outstanding awards at the end of the period.
(b) Represents fair value and weighted-average vesting period of awards at grant date.
(c) Represents cash paid for vested awards.

The fair value of the awards at the date of grant was based on the formula contained in the LTIP. The fair value of the awards will be recognized ratably over the vesting period and remeasured each quarter until settlement in accordance with the treatment of awards classified as liabilities prescribed in SFAS No. 123(R). The Partnership recorded $1.1 million and $0.4 million in Administrative and general expenses during 2007 and 2006 for the ratable recognition of the Phantom Common Unit awards fair value. Amounts recognized in 2005 were immaterial. The total estimated remaining unrecognized compensation expense related to the Phantom Common Units outstanding at December 31, 2007, of $2.0 million will be recognized over the average remaining vesting period of approximately 1.8 years.

On February 27, 2007, the general partner purchased 1,500 of the Partnership's common units in the open market at a price of $36.61 per unit and on March 23, 2006, the general partner purchased 1,000 common units in the open market at a price of $21.38 per unit. These units were granted under the LTIP to the independent directors as part of their director compensation. At December 31, 2007, 3,522,500 units were available for grants under LTIP.

Note 10: Net Income per Limited Partner Unit and Cash Distributions

The Partnership calculates net income per limited partner unit in accordance with Emerging Issues Task Force (EITF) Issue No. 03-6, *Participating Securities and the Two-Class Method under FASB Statement No. 128*. In Issue 3 of EITF No. 03-6, the EITF reached a consensus that undistributed earnings for a period should be allocated to a participating security based on the contractual participation rights of the security to share in those earnings as if all of the earnings for the period had been distributed. The Partnership's general partner holds contractual participation rights which are incentive distribution rights (IDRs) in accordance with the partnership agreement as follows:

	Total Quarterly Distribution	Marginal Percentage Interest in Distributions	
	Target Amount	Common and Subordinated Unitholders	General Partner
Minimum Quarterly Distribution	$0.3500	98.0%	2.0%
First Target Distribution	up to $0.4025	98.0%	2.0%
Second Target Distribution	above $0.4025 up to $0.4375	85.0%	15.0%
Third Target Distribution	above $0.4375 up to $0.5250	75.0%	25.0%
Thereafter	above $0.5250	50.0%	50.0%

The amounts reported for net income per limited partner unit on the Consolidated Statements of Income for the years ended December 31, 2007, 2006 and 2005, were adjusted to take into account an assumed allocation to the general partner's incentive distribution rights. Payments made on account of the incentive distribution rights are determined in relation to actual declared distributions. A reconciliation of the limited partners' interest in net income and net income available to limited partners used in computing net income per limited partner unit follows (in thousands, except weighted average units and per unit data):

	For the Year Ended December 31,		For the Period November 15, 2005 through December 31,
	2007	2006	2005
Limited partners' interest in net income	$ 220,726	$ 193,599	$ 35,272
Less assumed allocation to incentive distribution rights	4,323	5,187	-
Net income available to limited partners	216,403	188,412	35,272
Less assumed allocation to subordinated units	61,949	61,087	11,382
Net income available to common units	$ 154,454	$ 127,325	$ 23,890
Weighted average common units	82,510,917	68,977,766	68,256,122
Weighted average subordinated units	33,093,878	33,093,878	33,093,878
Net income per limited partner unit – common and subordinated units	$ 1.87	$ 1.85	$ 0.35

The Partnership has declared quarterly distributions per unit to unitholders of record, including common and subordinated units and the 2.0% general partner interest and IDRs held by its general partner as follows (in thousands, except distribution per unit):

Payable Date	Distribution per Unit	Amount Paid to Common and Subordinated Unitholders	Amount Paid to General Partner (Including IDRs)
February 25, 2008	$ 0.46	$ 56,925	$ 2,709
November 12, 2007	0.45	52,313	2,158
August 13, 2007	0.44	51,150	1,770
May 14, 2007	0.43	49,988	1,519
February 27, 2007	0.415	44,924	1,128
November 6, 2006	0.40	40,540	827
August 18, 2006	0.38	38,513	786
May 19, 2006	0.36	36,486	745
February 23, 2006	0.179*	18,121	370

*Distribution represented a prorated portion of the $0.35 per unit "minimum quarterly distribution" (as defined in the Partnership's partnership agreement) for the period November 15, 2005 through December 31, 2005.

Note 11: Income Tax

Results of operations for the year ended December 31, 2005, reflect a change in the tax status associated with the Partnership and Boardwalk Pipelines, coincident with the IPO. Accordingly, the Partnership recorded a charge-in-lieu of income taxes for the period January 1, 2005, through the date of the offering. Pursuant to the change in tax status, the Partnership also eliminated its balance of accumulated deferred income taxes at the date of the offering. The subsidiaries of the Partnership directly incur some income-based state taxes which are accrued as Income taxes and charge-in-lieu of income taxes on the Consolidated Statements of Income.

In July 2006, the FASB issued Interpretation No. (FIN) 48, *Accounting for Uncertainty in Income Taxes - An Interpretation of FASB Statement No. 109*, which is effective for the Partnership's year beginning January 1, 2007. This interpretation was issued to clarify the accounting for uncertainty in income taxes recognized in the financial statements by prescribing a comprehensive model for how a company should recognize, measure, present, and disclose uncertain tax positions taken or expected to be taken in a tax return. The Partnership has determined that FIN 48 does not have an impact on its results of operations. The Partnership's tax years 2005 through 2007 remain subject to examination by the Internal Revenue Service (IRS) and the states in which it operates.

Following is a summary of the provision for Income taxes and charge-in-lieu of income taxes for the periods ended December 31, 2007, 2006 and 2005 (in thousands):

	For the Year Ended December 31, 2007	2006	2005
Current expense:			
Federal	-	-	$ 4,044
State	$ 787	$ 292	870
Total	787	292	4,914
Deferred provision (benefit):			
Federal	-	-	36,690
State	(18)	(39)	7,890
Elimination of cumulative deferred taxes	-	-	10,102
Total	(18)	(39)	54,682
Income taxes and charge-in-lieu of income taxes	$ 769	$ 253	$ 59,596

Reconciliations from the provision at the statutory rate to the Income tax and charge-in-lieu of income taxes provision are as follows (in thousands):

	For the Year Ended December 31, 2007	2006	2005
Provision at statutory rate	-	-	$ 43,583
Increases in taxes resulting from:			
State income taxes	$ 769	$ 253	5,694
Other, net	-	-	217
Elimination of deferred taxes	-	-	10,102
Income taxes and charge-in-lieu of income taxes	$ 769	$ 253	$ 59,596

As of December 31, 2007 and 2006, there were no significant deferred income tax assets or liabilities.

Note 12: Financial Instruments

The following methods and assumptions were used in estimating the Partnership's fair-value disclosures for financial instruments:

Cash and Cash Equivalents: For cash and short-term financial assets and liabilities, the carrying amount is a reasonable estimate of fair value due to the short maturity of those instruments.

Advances to Affiliates: Advances to affiliates, which are represented by demand notes, earn a variable rate of interest, which is adjusted regularly to reflect current market conditions. Therefore, the carrying amount is a reasonable estimate of fair value. The interest rate on intercompany demand notes is LIBOR plus one percent and is adjusted every three months.

Long-Term Debt: All long-term debt is publicly traded, except for debt held by Gulf South. Estimated fair value is based on quoted market prices and market prices of similar debt, for debt held by Gulf South, at December 31, 2007 and 2006.

The carrying amount and estimated fair values of the Partnership's financial instruments as of December 31, 2007 and 2006 were as follows (in thousands):

	2007		2006	
Financial Assets	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
Cash and cash equivalents	$ 317,319	$ 317,319	$ 399,032	$ 399,032
Financial Liabilities				
Long-term debt	$ 1,847,914	$ 1,834,161	$ 1,350,920	$ 1,318,293

Note 13: Accumulated Other Comprehensive Income (Loss)

The following table shows the components of Accumulated other comprehensive income, net of tax which is included in Partners' Capital on the Consolidated Balance Sheets (in thousands):

	For the Year Ended December 31,	
	2007	**2006**
(Loss) gain on cash flow hedges, net of tax	$ (8,891)	$ 8,309
Deferred components of net periodic benefit cost, net of tax	13,103	14,803
Total Accumulated other comprehensive income, net of tax	$ 4,212	$ 23,112

In 2008, the Partnership will recognize $8.7 million of the amounts shown above in earnings. This amount is comprised of increases to earnings of $1.2 million related to cash flow hedges and $7.5 million related to net periodic benefit cost.

Note 14: Major Customers and Transactions with Affiliates

Major Customers

Operating revenues received from the Partnership's major customer (in thousands) and the percentage of Total operating revenues were:

	For the Year Ended December 31,					
	2007		2006		2005	
Customer	**Revenue**	**%**	**Revenue**	**%**	**Revenue**	**%**
Atmos Energy	$ 63,900	10.0 %	$ 56,413	9.3 %	$ 61,774	11.0 %

Natural gas price volatility has increased dramatically in recent years, which has materially increased credit risk related to gas loaned to customers. As of December 31, 2007, the amount of gas loaned by the operating subsidiaries was approximately 12.7 TBtu and, assuming an average market price during December 2007 of $7.13 per MMBtu, the market value of that gas was approximately $90.6 million. If any significant customer should have credit or financial problems resulting in a delay or failure to repay the gas owed to the operating subsidiaries, this could have a material adverse effect on the Partnership's financial condition, results of operations and cash flows.

Transactions with Affiliates

Loews provides a variety of corporate services to the Partnership and its subsidiaries under services agreements. Services provided by Loews include, among others, information technology, tax, risk management, internal audit and corporate development services. Loews charged $12.1 million, $13.0 million, and $9.7 million for the years ended December 31, 2007, 2006 and 2005 to the Partnership based on the actual time spent by Loews personnel performing these services, plus related expenses.

Distributions paid related to common and subordinated units held by BPHC, 2.0% general partner interest and IDRs held by Boardwalk GP were $156.4 million during 2007 and $116.6 million during 2006.

The Partnership pays franchise and certain other taxes on behalf of BPHC and records a note receivable from BPHC for the amounts paid, which is settled quarterly. The notes accrue interest at LIBOR plus one percent. In 2007 and 2006, the Partnership paid $3.4 million and $0.8 million on behalf of BPHC. A note receivable of $1.6 million remained at December 31, 2007.

Note 15: Recently Issued Accounting Pronouncements

SFAS No. 157, Fair Value Measurements

On September 15, 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*. Fair value refers to the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants in the market in which the reporting entity transacts. The standard clarifies the principle that fair value should be based on the assumptions market participants would use when pricing the asset or liability. In support of this principle, the standard establishes a fair value hierarchy that prioritizes the information used to develop those assumptions. The fair value hierarchy gives the highest priority to quoted prices in active markets and the lowest priority to unobservable data, for example, the reporting entity's own data. Under the standard, fair value measurements would be separately disclosed by level within the fair value hierarchy. The Statement is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. The Partnership is currently evaluating the impact, if any, that SFAS No. 157 would have on its financial statements.

SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities- including an amendment of SFAS No. 115*. SFAS No. 159 allows companies to elect to measure financial assets and financial liabilities at fair value. Unrealized gains and losses on items for which the fair value option has been chosen are reported in earnings. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. The effective date for the Partnership is January 1, 2008. The Partnership is currently evaluating the impact, if any, of adopting SFAS No. 159 on its financial statements.

Note 16: Supplemental Disclosure of Cash Flow Information (in thousands):

	For the Year Ended December 31,		
	2007	**2006**	**2005**
Cash paid during the period for:			
Interest (net of amount capitalized)	$ 46,106	$ 58,111	$ 45,357
Income taxes, net	340	215	-
Non-cash capital contribution	-	-	681,809
Non-cash dividends	-	-	101,401

Note 17: Selected Quarterly Financial Data (Unaudited)

The Partnership's operating income may vary by quarter. Based on the current rate structure, the operating subsidiaries experience higher income in the first and fourth quarters as compared to the second and third quarters. The following tables summarize selected quarterly financial data for 2007 and 2006 for the Partnership (in thousands, except for earnings per unit):

	2007 For the Quarter Ended:			
	December 31	September 30	June 30	March 31
Operating revenues	$ 169,882	$ 134,732	$ 150,542	$ 188,112
Operating expenses	89,048	86,185	106,236	95,766
Operating income	80,834	48,547	44,306	92,346
Interest expense, net	9,704	9,003	8,567	12,216
Other (income) expense	(1,232)	(575)	159	(334)
Income before income taxes	72,362	40,119	35,580	80,464
Income taxes	267	140	132	230
Net income	$ 72,095	$ 39,979	$ 35,448	$ 80,234
Earnings per unit:				
Common units	$ 0.56	$ 0.35	$ 0.35	$ 0.61
Subordinated units	$ 0.56	$ 0.30	$ 0.17	$ 0.61

	2006 For the Quarter Ended:			
	December 31	September 30	June 30	March 31
Operating revenues	$ 171,489	$ 133,045	$ 128,662	$ 174,446
Operating expenses	92,811	88,272	82,798	89,813
Operating income	78,678	44,773	45,864	84,633
Interest expense, net	13,882	14,414	14,510	15,088
Other income	(366)	(406)	(792)	(185)
Income before income taxes	65,162	30,765	32,146	69,730
Income taxes	(111)	118	246	-
Net income	$ 65,273	$ 30,647	$ 31,900	$ 69,730
Earnings per unit:				
Common units	$ 0.57	$ 0.35	$ 0.35	$ 0.58
Subordinated units	$ 0.57	$ 0.19	$ 0.22	$ 0.58

Note 18: Disposition of Coal Reserves

The Partnership has begun efforts to sell its investment in certain coal reserves along the Ohio River in northern Kentucky and southern Indiana that were originally acquired in the 1970's. A data room has been made available to prospective buyers. The book value of the assets at December 31, 2007 and 2006 was zero. The Partnership expects to complete a sale of the assets in 2008.

Note 19: Guarantee of Securities of Subsidiaries

The Partnership has no independent assets or operations other than its investment in its subsidiaries. The Partnership's operating subsidiaries have issued securities which have all been fully and unconditionally guaranteed by the Partnership. The Partnership does have separate partners' capital including publicly traded limited partner common units.

The Partnership's subsidiaries have no significant restrictions on their ability to pay distributions or make loans to the Partnership and have no restricted assets at December 31, 2007. See Note 7 for additional information.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

We maintain a system of disclosure controls and procedures which is designed to ensure that information required to be disclosed by us in reports that we file or submit under the federal securities laws, including this report is recorded, processed, summarized and reported on a timely basis. These disclosure controls and procedures include controls and procedures designed to ensure that information required to be disclosed by us under the federal securities laws is accumulated and communicated to us on a timely basis to allow decisions regarding required disclosure.

Our principal executive officer (CEO) and principal financial officer (CFO) undertook an evaluation of our disclosure controls and procedures as of the end of the period covered by this report. The CEO and CFO have concluded that our controls and procedures were effective as of December 31, 2007.

Changes in Internal Control over Financial Reporting

There were no other changes in our internal control over financial reporting that occurred during the quarter ended December 31, 2007, that have materially affected or that are reasonably likely to materially affect our internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting for us. Our internal control system was designed to provide reasonable assurance regarding the preparation and fair presentation of our published financial statements.

There are inherent limitations to the effectiveness of any control system, however well designed, including the possibility of human error and the possible circumvention or overriding of controls. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Management must make judgments with respect to the relative cost and expected benefits of any specific control measure. The design of a control system also is based in part upon assumptions and judgments made by management about the likelihood of future events, and there can be no assurance that a control will be effective under all potential future conditions. As a result, even an effective system of internal control over financial reporting can provide no more than reasonable assurance with respect to the fair presentation of financial statements and the processes under which they were prepared.

Our management assessed the effectiveness of our internal control over financial reporting as of December 31, 2007. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control – Integrated Framework*. Based on this assessment, our management believes that, as of December 31, 2007, our internal control over financial reporting was effective. Deloitte & Touche LLP, the independent registered public accounting firm that audited our financial statements included in Item 8 of this Report, has issued a report on our internal control over financial reporting.

Item 9B. Other Information

None.

PART III

Item 10. Directors and Executive Officers of the Registrant

Management of Boardwalk Pipeline Partners, LP

Boardwalk GP manages our operations and activities on our behalf. The operations of Boardwalk GP are managed by its general partner, Boardwalk GP, LLC (BGL). We sometimes refer to Boardwalk GP and BGL collectively as "our general partner." Our general partner is not elected by unitholders and is not subject to re-election on a regular basis in the future. Unitholders are not entitled to elect the directors of our general partner or directly or indirectly participate in our management or operation. Our general partner owes a fiduciary duty to our unitholders. Our general partner is liable, as general partner, for all of our debts (to the extent not paid from our assets), except for indebtedness or other obligations that are made specifically nonrecourse to it. Whenever possible, our general partner intends to cause us to incur indebtedness or other obligations that are nonrecourse to it. BGL has a board of directors that oversees our management, operations and activities. We refer to the board of directors of BGL, the members of which are appointed by BPHC, as our Board.

Whenever our general partner makes a determination or takes or declines to take an action in its individual, rather than representative, capacity, it is entitled to make such determination or to take or decline to take such other action free of any fiduciary duty or obligation to any limited partner and is not required to act in good faith or pursuant to any other standard imposed by our partnership agreement or under any law. Examples include the exercise of its limited call rights on our units, as provided in our partnership agreement, its voting rights with respect to the units it owns, its registration rights and its determination whether or not to consent to any merger or consolidation of the Partnership all of which are described in our partnership agreement. Actions of our general partner which are made in its individual capacity will be made by BPHC, the sole member of BGL, rather than by our Board.

Directors and Executive Officers

The following table shows information for the directors and executive officers of BGL:

Name	Age	Position
Rolf A. Gafvert	54	Chief Executive Officer, President and Director
Jamie L. Buskill	43	Chief Financial Officer, Senior Vice-President and Treasurer
Brian A. Cody	50	Senior Vice President of Marketing and Chief Commercial Officer
John C. Earley Jr.	45	Senior Vice President of Operations
Michael E. McMahon	52	Senior Vice President and General Counsel, Secretary
Arthur L. Rebell	67	Director, Chairman of the Board
William R. Cordes	59	Director
Thomas E. Hyland	62	Director
Jonathan E. Nathanson	46	Director
Mark L. Shapiro	63	Director
Andrew H. Tisch	58	Director

All directors have served since 2005 except for Mr. Cordes who was elected to the Board in October 2006. All directors serve until replaced or upon their voluntary resignation.

Rolf A. Gafvert—Mr. Gafvert has been the Chief Executive Officer of BGL since February 2007 and President since February 2008. Prior to February 2007 he had been the Co-President of BGL since its inception in 2005. Mr. Gafvert has been the President of Gulf South since 2000 and has been employed by Gulf South or its predecessors since 1993. During that time he also served in various management roles for affiliates of Gulf South, including President of Koch Power, Inc., Managing Director of Koch Energy International and Vice President of Corporate Development for Koch Energy, Inc. Mr. Gafvert is on the Board of Directors of the Interstate Natural Gas Association of America.

Jamie L. Buskill—Mr. Buskill has been the Chief Financial Officer of BGL since its inception in 2005. Mr. Buskill is also the Vice President, Chief Financial Officer and Treasurer of Texas Gas. Mr. Buskill has been employed by Texas Gas in that capacity since Texas Gas was acquired by Boardwalk Pipelines in May 2003. Prior thereto he served in various management roles for Texas Gas and its affiliates since 1986, including Assistant Treasurer and Financial Reporting Manager from 1998 until May 2003.

Brian A. Cody— Mr. Cody has been the Chief Commercial Officer of BGL since March, 2007. Mr. Cody has served in various management roles for Gulf South including: Vice President of Business Development from 2006 to 2007, Chief Financial Officer from 2005 to 2006, Vice President of Long Term Marketing from 2003 to 2005 and Controller from 2000 to 2003 . He has been employed by Gulf South or its predecessors since 1987 and is a Certified Public Accountant.

John C. Earley Jr. —Mr. Earley has been the Senior Vice President of Operations of BGL since March 2007. Prior thereto he had been Senior Vice President of Operations for Gulf South since 2001. Mr. Earley has held various senior leadership roles prior to 2001 and has been employed by Gulf South or it predecessors since 1995.

Michael E. McMahon—Mr. McMahon has been the Senior Vice President and General Counsel of BGL since February 2007. Prior thereto he served as Senior Vice President and General Counsel of Gulf South since 2001. Mr. McMahon has been employed by Gulf South or its predecessors since 1989. Mr. McMahon also serves on the legal committees of Interstate Natural Gas Association of America and the American Gas Association.

Arthur L. Rebell—Mr. Rebell is a Senior Vice President at Loews. He has been employed by Loews in that capacity since 1998 and has been primarily responsible for investments, corporate strategy, mergers and acquisitions and corporate finance. Mr. Rebell also serves as a director for Diamond Offshore Drilling, Inc., a subsidiary of Loews.

William R. Cordes—Mr. Cordes retired as President of Northern Border Pipeline Company in April 2007. He had worked in the natural gas industry for more than 35 years, including as Chief Executive Officer of Northern Border Partners, LP and President of Northern Natural Gas Company and Transwestern Pipeline Company. Mr. Cordes is also a member of the Board for the Kayne Anderson Energy Development fund.

Thomas E. Hyland—Mr. Hyland was a partner in the global accounting firm of PricewaterhouseCoopers, LLP from 1980 until his retirement in July 2005.

Jonathan E. Nathanson—Mr. Nathanson is Vice President—Corporate Development of Loews. He has been employed by Loews in that capacity since 2001 and is responsible for mergers and acquisitions and corporate finance.

Mark L. Shapiro—Mr. Shapiro has been a private investor since 1998.

Andrew H. Tisch—Mr. Tisch has been Co-Chairman of the Board of Loews since January 2006 and is the Chairman of the Executive Committee and a member of the Office of the President of Loews. He has served as a director of Loews since 1985. Mr. Tisch also serves as a director of CNA Financial Corporation, a subsidiary of Loews, and is Chairman of the Board of K12 Inc.

Audit Committee

Our Board's Audit Committee presently consists of Thomas E. Hyland, Chairman, Mark L. Shapiro and William R. Cordes, each of whom is an independent director and satisfies the additional independence and other requirements for Audit Committee members provided for in the listing standards of the NYSE. The Board of Directors has determined that Mr. Hyland qualifies as an "audit committee financial expert," under Securities and Exchange Commission (SEC) rules.

The primary function of the Audit Committee is to assist our Board in fulfilling its responsibility to oversee management's conduct of our financial reporting process, including review of our financial reports and other financial information, our system of internal accounting controls, our compliance with legal and regulatory requirements, the qualifications and independence of our independent registered public accounting firm (independent auditors) and the performance of our internal audit function and independent auditors. The Audit Committee has sole authority to appoint, retain, compensate, evaluate and terminate our independent auditors and to approve all engagement fees and terms for our independent auditors.

Conflicts Committee

Under our partnership agreement, our Board must have a Conflicts Committee consisting of two or more independent directors. Our Conflicts Committee presently consists of Mark L. Shapiro, Chairman, Thomas E. Hyland and William R. Cordes. The primary function of the Conflicts Committee is to determine if the resolution of any conflict of interest with our general partner or its affiliates is fair and reasonable. Any matters approved by the Conflicts Committee will be conclusively deemed to be fair and reasonable, approved by all of the partners and not a breach by our general partner of any duties it may owe to our unitholders.

Executive Sessions of Non-Management Directors

Our Board's non-management directors, from time to time as such directors deem necessary or appropriate, meet in executive sessions without management participation. The Chairman of the Audit Committee and the Conflicts Committee alternate serving as the presiding director at these meetings.

Corporate Governance Guidelines and Code of Conduct

Our Board has adopted Corporate Governance Guidelines to guide it in its operation and a Code of Business Conduct and Ethics applicable to all of the officers and directors of BGL, including the principal executive officer, chief financial officer, principal accounting officer, and all of the directors, officers and employees of our subsidiaries. We intend to post changes to or waivers of this Code for BGL's principal executive officer, principal financial officer and principal accounting officer on our website.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16 of the Exchange Act requires our directors and executive officers, and persons who own more than 10.0% of a registered class of our equity securities, to file initial reports of ownership and reports of changes in ownership with the SEC. Such persons are required by SEC regulation to furnish us with copies of all Section 16(a) forms they file. Based solely on our review of the copies of such forms furnished to us and written representations from our executive officers and directors, we believe that all Section 16(a) filing requirements were met during 2007, in a timely manner, other than one late Form 3 filing for each of Messrs. Cody, Earley and McMahon and one late Form 4 filing for H. Dean Jones II and each of Messrs. Buskill, Cody, Cordes, Earley, Gafvert, Hyland, McMahon and Shapiro.

Item 11. Executive Compensation

Compensation Discussion and Analysis

Overview

The objective of our executive compensation program is to attract and retain highly qualified executive officers and motivate them to provide a high level of performance for the Partnership and our unitholders, including maintaining current levels of unitholder distributions and taking prudent steps to grow unitholder distributions. To meet this objective we have established a compensation policy for our executive officers which combines elements of base salary and cash and equity-based incentive compensation, as well as benefits. We have selected these elements and otherwise structured our executive compensation practices to align the interests of our executives with those of our unitholders and our general partner, improve retention of our executives and appropriately reward their performance both in the long and short term. In doing so, we may consider the executive compensation programs of other companies engaged in similar businesses to ours and historical compensation policies and practices of our operating subsidiaries, as well as applicable tax and accounting impacts of executive compensation, including the tax implications of providing equity-based compensation to our employees in light of our being a limited partnership.

As discussed elsewhere in this Report, our Board does not maintain a Compensation Committee. Therefore, the compensation for Rolf Gafvert our Chief Executive Officer (CEO), Jamie L. Buskill our Chief Financial Officer (CFO) and our three other most highly compensated executive officers (together with our former President, H. Dean Jones II, who has resigned as an officer and director in conjunction with his announced retirement that will be effective March 1, 2008), our “Named Executive Officers”, is reviewed with and is subject to the approval of our entire Board, with Mr. Gafvert not participating in those discussions with respect to his own compensation. Named Executive Officers are those officers whose compensation is required to be reported in accordance with Item 402, *Executive Compensation*, of SEC Regulation S-K rules.

The principal components of compensation for our Named Executive Officers are:

- base salary;
- annual incentive compensation awards, including cash bonuses and grants of phantom common units (Phantom Common Units) under our LTIP;
- annual grants of phantom general partner units (Phantom GP Units) under our SLTIP; and
- retirement, medical and related benefits.

In establishing the aggregate amount of compensation for our Named Executive Officers for a given year, we do not rely on formula-driven plans which could result in unreasonably high compensation levels. Instead, the primary factor in setting compensation is an evaluation of the individual's performance in the context of our overall performance for such year, particularly the individual’s contribution to our financial performance during the year, as well as the compensation paid to the individual in prior years. In light of the shortage of excellent management talent in our industry and our desire to retain our key executives, we may also review and consider compensation levels and types in other companies that are engaged in similar businesses to maintain an understanding of the market for executive talent. Based on these factors, we determine an overall level of compensation.

Base Salary

Our executive compensation policies have emphasized the incentive-based compensation elements discussed below. As a result, the base salaries of our executive officers generally have remained unchanged through the end of 2007, with modest adjustments made from year to year based on merit or other factors. Each year we review the overall mix of compensation to determine if we need to vary any one item of an executive’s compensation package.

Incentive Compensation – Cash Bonuses and Phantom Common Unit Awards

A significant portion of the compensation of our Named Executive Officers consists of an annual incentive compensation award, which is an aggregate dollar amount determined by our Board that is paid in part as a cash bonus and in part as an award of Phantom Common Units. In order to balance our goals of motivating our executives to consider long-term results for our unitholders and providing them with appropriate current cash compensation, we have targeted these compensation elements as approximately three-fourths cash bonus and one-fourth as an award of Phantom Common Units for our most senior executives.

Prior to the beginning of a year, the CEO proposes to the Board bonus targets including cash and equity components for the Partnership as a whole, based on meeting specific financial measures, operating goals and project milestones. At the end of the year, the CEO makes recommendations to the Board regarding amounts to pay both Named Executive Officers and other employees based on whether targets for the year were met and based upon the Named Executive Officers' individual performance and contributions to the Company. The CEO's compensation is determined by the Board based upon a similar appraisal of performance and contributions.

Since we are a limited partnership and our Named Executive Officers are employed by our operating subsidiaries, the executives would incur significant adverse individual tax consequences if they would own our units directly; for example by being taxed as a partner rather than as an employee. Furthermore, the ownership of units by our executives would negatively impact the tax status of our benefit plans. As a result, we have chosen to award our executives equity-based compensation in the form of Phantom Common Units, the economic value of which is directly tied to the value of our common units, but which do not confer any rights of ownership to the grantee. The value of a Phantom Common Unit is equal to the value of a common unit plus accumulated distributions made on such common unit since the award date and that value is paid to the executive by us in cash at the end of a vesting period if the executive is still employed on that date. Our Board has discretion to determine the amount, vesting schedule and certain other terms of awards under our LTIP.

The number of Phantom Common Units awarded to a Named Executive Officer is determined by dividing the dollar amount of such executive's incentive based compensation that has been allocated to such an award by the closing price of our common units on the NYSE on the date of grant. For example, if an executive is awarded $250,000 of incentive compensation, of which $60,000 is designated for an award of Phantom Common Units (the balance being paid as a cash bonus), and the closing price of our common units on the NYSE on the grant date is $30.00 per unit, the executive would be awarded 2,000 Phantom Common Units for that year.

The Phantom Common Units awarded to our Named Executive Officers vest 50.0% on the second anniversary of the grant date and 50.0% on the third anniversary of the grant date, and become payable in cash upon vesting. Since the value of the Phantom Common Units is tied directly to the price of our common units, and the amount of distributions made on those units during the vesting period, this element of compensation directly aligns the interests of our Named Executive Officers with those of our common unitholders. It also promotes retention because the awards would be forfeited if an employee were to resign prior to the vesting date.

We exceeded our financial and operational goals for 2007 and increased our distributions to unitholders in each quarter. As a result, we awarded the full amount of incentive compensation we had targeted for 2007 to our key employees including the Named Executive Officers, of which approximately 75.0% was paid as annual cash bonuses and 25.0% was awarded as Phantom Common Units. In making these awards, our Board considered the factors discussed above, with particular emphasis on the contributions made by the individual executives in 2007 to the success of the expansion projects we have undertaken which are described elsewhere in this Report, among other strategic goals and objectives.

Phantom GP Units

Our Board has also made awards of Phantom GP Units to our Named Executive Officers. These awards give the grantee an economic interest in the performance of our general partner, including our general partner's incentive distribution rights, but do not confer any right of ownership of our general partner to the grantee. Phantom GP Units provide the holder with an opportunity, subject to vesting, to receive a lump sum cash payment in an amount determined under a formula based on the amount of cash distributions made by us to our general partner during the four quarters preceding the vesting date and the implied yield on our common units, up to a maximum of $50,000 per unit.

These awards recognize and reward our Named Executive Officers based on our long term performance and encourage them to continue their employment with us since any awards would be forfeited if the executive is not employed by us on the vesting date. They also encourage our Named Executive Officers to carefully focus on long term returns to unitholders and our general partner when making management decisions. Since the value of these awards is directly linked to our performance and the value of our common units and of our general partner, they further align the interests of our Named Executive Officers with those of our unitholders.

We awarded an aggregate of 116 Phantom GP Units in December 2007, which vest in 4.0 years, to 21 of our key employees, of which 65 were awarded to our Named Executive Officers. In making these awards, our Board considered each grantee's overall performance, with particular emphasis on the contributions made by the individual executive to our expansion projects, among other strategic goals and objectives.

Employee Benefits

Each Named Executive Officer participates in benefit programs available generally to salaried employees of the operating subsidiary which employs such officer, including health and welfare benefits and a qualified defined contribution 401(k) plan that includes a dollar-for-dollar match on elective deferrals of up to 6.0% of eligible compensation within Internal Revenue Code (IRC) requirements. Certain Named Executive Officers participate in a defined contribution money purchase plan available to employees of Gulf South, while others participate in a defined benefit cash balance pension plan available to employees of Texas Gas, which includes a non-qualified restoration plan for amounts earned in excess of IRC limits for qualified retirement plans. Certain Named Executive Officers are also eligible for retiree medical benefits after reaching age 55 as part of a plan offered to other Texas Gas employees.

Equity Ownership Guidelines

As discussed above, our executives would suffer significant negative tax consequences by owning our units directly. As a result, we do not have a policy, nor any guidelines, regarding ownership of our equity by our management. We therefore seek to align the interests of management with our unitholders by granting the Phantom Common Units and Phantom GP Units.

Board of Directors Report on Executive Compensation

In fulfilling its responsibilities, our Board has reviewed and discussed the Compensation Discussion and Analysis with our management. Based on this review and discussion, the Board recommended that the Compensation Discussion and Analysis be included in this annual report on Form 10-K.

By the members of the Board of Directors:

William R. Cordes
Rolf A. Gafvert
Thomas E. Hyland
Jonathon E. Nathanson
Arthur L. Rebell, Chairman
Mark L. Shapiro
Andrew H. Tisch

Compensation Committee Interlocks and Insider Participation

As discussed above, our Board does not maintain a Compensation Committee. Our entire Board of Directors performs the functions of such a committee. None of our directors, except Mr. Gafvert, have been or are officers or employees of us or our subsidiaries. Mr. Gafvert participates in deliberations of our Board with regard to executive compensation generally, but does not participate in deliberations or Board actions with respect to his own compensation. None of our executive officers served as director or member of a compensation committee of another entity that has or has had an executive officer who served as a member of our Board during 2007 or 2006.

Summary of Executive Compensation

The following table shows a summary of total compensation earned by our Named Executive Officers during 2007 and 2006:

Summary Compensation Table

Name and Position	Year	Salary	Bonus (1)	Stock Awards (2)	Option Awards	Non-Equity Incentive Plan Compensation (3)	Change in Pension value and nonqualified deferred compensation earnings	All Other Compensation	Total
Rolf A. Gafvert:									
CEO (PEO)	2007	$ 323,365	$ 300,000	$ 175,253	-	$ 682,664	-	$ 35,360(4)	$ 1,516,642
	2006	240,000	300,000	112,944	-	183,442	-	32,149(4)	868,535
H. Dean Jones II: (10)									
	2007	326,534	275,000	80,013	-	401,786	$ 177,404(5)	31,099(5)	1,291,836
	2006	325,000	195,000	59,778	-	110,065	154,458(5)	24,432(5)	868,733
Jamie L. Buskill:									
CFO (PFO)	2007	225,000	225,000	36,092	-	302,679	46,602(6)	14,386(6)	849,759
	2006	225,000	100,000	26,196	-	87,011	40,333(6)	14,292(6)	492,832
Brian A. Cody:									
SVPM	2007	228,846	175,000	59,288	-	364,137	-	23,107(7)	850,378
John C. Earley Jr.:									
SVPO	2007	226,154	175,000	73,447	-	326,116	-	23,681(8)	824,398
Michael E. McMahon:									
SVPGC	2007	216,346	125,000	59,288	-	297,545	-	28,938(9)	727,117

(1) Reflects cash amounts paid in 2008 and 2007 to the Named Executive Officers for services performed by them during 2007 and 2006.

(2) Represents compensation expense accrued for 2007 and 2006 related to Phantom Common Units granted in 2007, 2006 and 2005. The accruals were made pursuant to SFAS No. 123(R), *Share Based Payments*. See footnote (1) to the Grants of Plan-Based Awards table presented below.

(3) Represents compensation expense accrued for 2007 and 2006 related to Phantom GP Units granted in 2007 and 2006. The accruals were made pursuant to SFAS No. 123(R). See footnote (1) to the Grants of Plan-Based Awards table presented below.

(4) Includes for 2007: matching contributions under 401(k) plan ($13,500), employer contributions to the Gulf South Money Purchase Plan ($9,000), sale of vacation time ($6,250), club memberships ($4,781), imputed life insurance premiums, travel clubs and preferred parking; for 2006: matching contributions under 401(k) plan ($13,200), employer contributions to the Gulf South Money Purchase Plan ($8,800), club memberships ($6,508), physical medical examination reimbursement, preferred parking, sporting event tickets and imputed life insurance premiums.

(5) Includes for 2007: matching contributions under 401(k) plan ($13,500), club memberships ($7,200), salary continuation plan ($6,124), imputed life insurance premiums ($2,741) and tax gross-up on spouse travel; for 2006: matching contributions made under a 401(k) plan ($13,200), club memberships ($7,200), spouse travel, tax gross-up on spouse travel and imputed life insurance premiums. The total included in the change in pension value and nonqualified deferred compensation column for 2007 and 2006 includes the change in qualified retirement plan account balance ($64,897 and $60,562), interest and pay credits for the supplemental retirement plan ($101,028 and $83,935) and excess nonqualified deferred compensation plan earnings ($11,479 and $9,961).

(6) Includes for 2007: matching contributions under 401(k) plan ($13,500) and imputed life insurance premiums; for 2006: matching contributions made under a 401(k) plan ($13,200), spouse travel and imputed life insurance premiums. The total included in the change in pension value and nonqualified deferred compensation column for 2007 and 2006 includes the change in qualified retirement plan account balance ($31,188 and $28,675) and interest and pay credits for the supplemental retirement plan ($15,414 and $11,658).

(7) Includes for 2007: matching contributions under 401(k) plan ($13,500), employer contributions to the Gulf South Money Purchase Plan ($8,426), imputed life insurance premiums, travel clubs and preferred parking.

(8) Includes for 2007: matching contributions under 401(k) plan ($13,500), employer contributions to the Gulf South Money Purchase Plan ($9,000), imputed life insurance premiums, travel clubs and preferred parking.

(9) Includes for 2007: matching contributions under 401(k) plan ($8,481), sale of vacation time ($10,385), employer contributions to the Gulf South Money Purchase Plan ($8,654), imputed life insurance premiums, travel clubs and preferred parking.

(10) H. Dean Jones II has resigned as an officer and director in conjunction with his announced retirement that will be effective March 1, 2008.

Grants of Plan-Based Awards

The following table displays information regarding grants during 2007 and 2006 to our Named Executive Officers of plan-based awards, including Phantom GP Unit awards under our Strategic Long Term Incentive Plan and Phantom Common Unit awards under our Long Term Incentive Plan:

Grants of Plan-Based Awards

		Estimated future payouts under non-equity incentive plan awards (1)			Estimated future payouts under equity incentive plan awards						
Name	**Grant Date**	**Threshold ($)**	**Target ($)**	**Maximum ($)**	**Threshold (#)**	**Target (#)**	**Maximum (#)**	**All other stock awards: number of shares of stock or units (#)**	**All other options awards: number of securities underlying options (#)**	**Exercise or base price of option awards ($/sh)**	**Grant Date Fair Value of Stock and Option Awards ($) (2)**
Rolf A. Gafvert:											
	12/14/07	-	-	1,250,000	-	-	-	6,532	-	-	200,000
	12/20/06	-	-	1,250,000	-	-	-	6,427	-	-	200,000
	7/24/06	-	-	1,250,000	-	-	-	-	-	-	-
H. Dean Jones II:											
	12/20/06	-	-	750,000	-	-	-	2,571	-	-	80,000
	7/24/06	-	-	750,000	-	-	-	-	-	-	-
Jamie L. Buskill:											
	12/14/07	-	-	600,000	-	-	-	-	-	-	-
	12/20/06	-	-	500,000	-	-	-	1,205	-	-	37,500
	7/24/06	-	-	600,000	-	-	-	-	-	-	-
Brian A. Cody:											
	12/14/07	-	-	500,000	-	-	-	3,266	-	-	100,000
John C. Earley Jr.:											
	12/14/07	-	-	450,000	-	-	-	3,266	-	-	100,000
Michael E. McMahon:											
	12/14/07	-	-	450,000	-	-	-	3,266	-	-	100,000

(1) On July 24, 2006, our SLTIP became effective. The plan provides for the issuance of up to 500 Phantom GP Units to our key employees. Each Phantom GP Unit entitles the holder thereof, upon vesting, to a lump sum cash payment in an amount determined by a formula based on cash distributions made by us to our general partner during the four quarters preceding the vesting date and the implied yield on our common units, up to a maximum of $50,000 per unit. On December 14, 2007 Messrs. Gafvert, Buskill, Cody, Earley, and McMahon were awarded 25, 12, 10, 9 and 9 Phantom GP Units that have a 4.0 year vesting period. On December 20, 2006, Messrs. Gafvert, Jones and Buskill were awarded 25, 15 and 10 Phantom GP Units that have a 4.0 year vesting period. Concurrent with the approval of the Plan, on July 24, 2006, Messrs. Gafvert, Jones and Buskill were awarded 25, 15 and 12 Phantom GP Units that have a 3.5 year vesting period. The fair value of the awards was determined as of the date of grant and will be remeasured each quarter until settlement in accordance with the treatment of awards classified as liabilities prescribed in SFAS No. 123(R). The fair value at grant date of the December 14, 2007 grants, December 20, 2006 grants and July 24, 2006 grants were $50,000, $50,000 and $27,422, respectively, per GP Phantom Unit. The fair value of the awards will be recognized ratably over the vesting period. As of December 31, 2007, the remeasured fair value of each of the December 14, 2007, December 20, 2006 and July 24, 2006 grants was $50,000. See footnote (2) to the Outstanding Equity Awards at Fiscal Year –End table presented below. Note 9 in Item 8 of this Report contains more information regarding our SLTIP.

(2) Reflects the fair value at the date of grant of Phantom Common Units under our LTIP. The closing price of our common units on such date on the NYSE for 2007 was $30.62 and for 2006 was $31.12. Each such grant includes a tandem grant of Distribution Equivalent Rights (DERs); vests 50.0% on the second anniversary of the grant date and 50.0% on the third anniversary of the grant date; and will be payable to the grantee in cash upon vesting in an amount equal to the sum of the fair market value of the units (as defined in the plan) that vest on the vesting date plus the vested amount then credited to the grantee's DER account, less applicable taxes. Note 9 in Item 8 of this Report contains more information regarding our LTIP.

Outstanding Equity Awards at Fiscal Year-End

The table displayed below shows the total outstanding equity awards in the form of Phantom Common Units, awarded under our LTIP and held by our Named Executive Officers at December 31, 2007 and 2006:

Outstanding Equity Awards at Fiscal Year End

		Option Awards					Stock Awards			
Name	**Year**	**Number of Securities Underlying Unexercised Options (#) Exercisable**	**Number of Securities Underlying Unexercised Options (#) Unexercisable**	**Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options (#)**	**Option Exercise Price ($)**	**Option Expiration Date**	**Number of Shares or Units of Stock that Have Not Vested (#)(1)**	**Market Value of Shares or Units of Stock that Have not Vested ($) (2)**	**Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights that Have Not Vested (#)**	**Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Rights that Have Not Vested ($)**
Rolf A. Gafvert	2007	-	-	-	-	-	16,974	541,074	-	-
	2006	-	-	-	-	-	14,457	456,155	-	-
H. Dean Jones II	2007						4,712	152,929	-	-
	2006	-	-	-	-	-	6,854	216,888	-	-
Jamie L. Buskill	2007						2,142	69,470	-	-
	2006	-	-	-	-	-	3,079	97,366	-	-
Brian A. Cody	2007	-	-	-	-	-	7,148	226,112	-	-
John C. Earley Jr.	2007	-	-	-	-	-	7,817	248,309	-	-
Michael E. McMahon	2007	-	-	-	-	-	7,148	226,112	-	-

(1) On December 14, 2007, Messrs. Gafvert, Cody, Earley and McMahon were awarded additional grants of Phantom Common Units in the amount of 6,532, 3,266, 3,266 and 3,266. On the December 14, 2007 grant date the closing sale price on the NYSE was $30.62. On December 20, 2006, Messrs. Gafvert, Jones and Buskill were awarded additional grants of Phantom Common Units in the amount of 6,427, 2,571 and 1,205. On the December 20, 2006 grant date the closing sale price on the NYSE was $31.12. On December 15, 2005, Phantom Common Units were awarded to Gafvert, Jones and Buskill in the amount of 8,030, 4,283 and 1,874. The vesting period is 3.5 years. On the grant date, the closing sales price on the common units on the NYSE was $18.68.

(2) The market value per share reported in the above table is based on the NYSE last sale price on December 31, 2007 of $31.10 and December 29, 2006 of $30.82. Included in the market value is the accumulated non-vested amounts related to the DER that were tandem grants to the Phantom Common Units referred to in footnote (1) above. Such DER amounts for Messrs. Gafvert, Jones, Buskill, Cody, Earley and McMahon were $13,183, $6,386, $2,854, $3,809, $5,200 and $3,809 in 2007 and for Messrs. Gafvert, Jones and Buskill were $10,590, $5,648 and $2,471 in 2006

Option Exercises and Stock Vested

All of the equity-based awards granted to our Named Executive Officers have been in the form of Phantom Common Units. We have not issued any awards in the form of options on our units to any employees including Named Executive Officers.

		Options Awards		Stock Awards (1)	
Name	**Year**	**Number of Shares Acquired on Exercise (#)**	**Value Realized on Exercise ($)**	**Number of Shares Acquired on Vesting (#)**	**Value Received on Vesting ($)**
Rolf A. Gafvert	2007	-	-	4,015	135,200
H. Dean Jones II	2007			2,142	72,129
Jamie L. Buskill	2007			937	31,552
Brian A. Cody	2007	-	-	669	22,528
John C. Earley Jr.	2007	-	-	1,339	45,090
Michael E. McMahon	2007	-	-	669	22,528

(1) All vested awards were paid out as a lump sum cash payment and at no time were units issued to or owned by the Named Executive Officers.

Pension Benefits

The table displayed below shows the present value of accumulated benefits for our Named Executive Officers. Pension benefits include both a qualified defined benefit cash balance plan and a non-qualified defined benefit supplemental cash balance plan (SRP).

Pension Benefits

Name	**Year**	**Plan Name**	**Number of Years Credited Service (#)**	**Present Value of Accumulated Benefit ($)**	**Payments During 2007 ($)**	**Payments During 2006 ($)**
H. Dean Jones II	2007	TGRP	27.1	535,760	-	-
		SRP	27.1	677,339	-	-
	2006	TGRP	26.1	470,863	-	-
		SRP	26.1	576,311	-	-
Jamie L. Buskill	2007	TGRP	21.3	173,837	-	-
		SRP	21.3	34,293	-	-
	2006	TGRP	20.3	142,649	-	-
		SRP	20.3	18,879	-	-

The Texas Gas Retirement Plan (TGRP) is a qualified defined benefit cash balance plan. Although this plan was closed to new participants in November 2006, most of our Texas Gas employees are eligible to participate in the TGRP. Participants in the plan vest after five years of credited service. One year of vesting service is earned for each calendar year in which a participant completes 1,000 hours of service.

Eligible compensation used in calculating the plan's annual compensation credits include total salary and bonus paid. The credit rate on all eligible compensation is 4.5% prior to age 30, 6.0% age 30 through 39, 8.0% age 40 through 49 and 10.0% age 50 and older. Additional credit rates on annual pay above Social Security Wage Base is 1.0%, 2.0%, 3.0% and 5.0% for the same age categories. On April 1, 1998, the TGRP was converted to a cash balance plan. Credited service up to March 31, 1998 is eligible for a past service credit of 0.3%. Additionally, participants may qualify for an early retirement subsidy if their combined age and service at March 31, 1998, totaled at least 55 points. The amount of the subsidy is dependent on the number of points and the participant's age of retirement. Upon retirement, the retiree may choose to receive their benefit from a variety of payment options which include a single life annuity, joint and survivor annuity options and a lump-sum cash payment. Joint and survivor benefit elections serve to reduce the amount of the monthly benefit payment paid during the retiree's life but the monthly payments continue for the life of the survivor after the death of the retiree. The TGRP has an early retirement provision that allows vested employees to retire early at age 55. At December 31, 2007, Mr. Jones was eligible for the age 55 early retirement provisions of the TGRP.

The credited years of service appearing in the table above are the same as actual years of service. No payments were made to the Named Executive Officers during 2007 or 2006. The present value of accumulated benefits payable to each of the Named Executive Officers, including the number of years of service credited to each Named Executive Officer, is determined using assumptions consistent with the assumptions used for financial reporting. Interest is credited to the cash balance at December 31, 2007, commencing in the year 2008, using a quarterly compounding up to the normal retirement date of age 65. Salary and bonus pay credits, up to the IRC allowable limits, increase the accumulated cash balance in the year earned. Credited interest rates used to determine the accumulated cash balance at the normal retirement date as of December 31, 2007, 2006, and 2005 were 4.79%, 4.85% and 4.47% and for future years, 4.5%, 4.25%, and 4.125%. The future normal retirement date accumulated cash balance is then discounted using an interest rate at December 31, 2007, 2006 and 2005 of 6.0%, 5.75% and 5.625%. The increase in the present value of accumulated benefit for the TGRP between December 31, 2007 and 2006 of $64,897 for Mr. Jones and $31,188 for Mr. Buskill is reported as compensation in the Summary Compensation Table above. The increase in the present value of accumulated benefit for the TGRP between December 31, 2006 and 2005 of $60,562 for Mr. Jones and $28,675 for Mr. Buskill is reported as compensation in the Summary Compensation Table above.

The Texas Gas SRP is a non-qualified defined benefit cash balance plan that provides supplemental retirement benefits for each Named Executive Officer for earnings that exceed the IRC compensation limitations for qualified defined benefit plans. The present value of accumulated benefit is calculated in the same manner as for TGRP. The increase in the present value of accumulated benefit for the SRP between December 31, 2007 and 2006 of $101,028 for Mr. Jones and $15,414 for Mr. Buskill is reported as compensation in the Summary Compensation Table above. The increase in the present value of accumulated benefit for the SRP between December 31, 2006 and 2005 of $83,935 for Mr. Jones and $11,658 for Mr. Buskill is reported as compensation in the Summary Compensation Table above.

Nonqualified Deferred Compensation

The following table shows nonqualified deferred compensation plan information for our Named Executive Officers. We currently do not have a nonqualified deferred compensation plan that allows for current or future deferrals of compensation. The amounts shown in the table are related to the Texas Gas Salary Continuation Plan that is closed to new participants and compensation deferrals:

Nonqualified Deferred Compensation (1)

Name	Year	Executive Contributions ($)	Registrant Contributions ($)	Aggregate Earnings ($)	Aggregate Withdrawals/ Distributions ($)	Aggregate Balance ($)
H. Dean Jones II	2007	-	-	26,313	-	275,969
	2006	-	-	23,524	-	249,656

(1) The Salary Continuation Plan became closed to new participants and compensation deferrals in 1995. The only activity in the plan is the addition of earnings on individual account balances and any withdrawals from account balances. Earnings on the deferred compensation balances are computed at the prime rate of interest plus 2.0%, compounded monthly. Aggregate earnings in 2007 include $11,479 and in 2006 include $9,961 reported in the Summary Compensation Table above.

Potential Payments Upon Termination or Change-in-Control

We have made grants of Phantom Common Units and Phantom GP Units, subject to vesting, to each of our Named Executive Officers, as discussed elsewhere in this Report. Each of the foregoing grants will vest immediately and become payable to the executive in cash upon a change of control of us, as defined in the applicable plan, or upon the termination of the executive's employment with us and our affiliates by reason of death, disability, retirement or termination by us other than for cause (as defined in such plans); provided, that with respect to the vesting of Phantom GP Units, the minimum distribution amount per unit (as defined in the applicable grant agreements) must have been met for the four consecutive calendar quarters ending on or immediately preceding such termination of employment. Assuming that a termination or change of control event resulting in accelerated vesting had occurred as of December 31, 2007, the Named Executive Officer (i) would be entitled to payment for each Phantom Common Unit held as of such date in an amount equal to $31.10, being the closing price of a common unit on such date on the NYSE, plus the distribution equivalent rights accumulated for such Phantom Common Unit from the date of grant; and (ii) would not be entitled to any payment on account of Phantom GP Units since the Minimum Distribution Amount was not met as of such date for any outstanding Phantom GP Units.

Director Compensation

Each director of BGL who is not an officer or employee of us, our subsidiaries, our general partner or an affiliate of our general partner is paid an annual cash retainer of $35,000 ($40,000 for the chair of the Audit Committee), payable in equal quarterly installments, $1,000 for each Board meeting attended which is not a regularly scheduled meeting, and an annual grant of 500 of our common units. Directors who are officers or employees of us, our subsidiaries, our general partner or an affiliate of our general partner do not receive the compensation described above. All directors are reimbursed for out-of-pocket expenses they incur in connection with attending Board and committee meetings and will be fully indemnified by us for actions associated with being a director to the extent permitted under Delaware law. The following table displays information related to director compensation for 2007:

Name	Fees Earned or Paid in Cash ($) (1)	Stock Awards ($) (3)	Option Awards ($)	Non-Equity Incentive Plan Compensation ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings	All Other Compensation including perquisites ($)	Total ($)
William R. Cordes	49,000	18,305	-	-	-	-	67,305
Thomas E. Hyland	56,000(2)	18,305	-	-	-	-	74,305
Mark L. Shapiro	50,000	18,305	-	-	-	-	68,305

(1) Represents amounts paid in cash for 2007.
(2) Chairman of Audit Committee.
(3) On March 5, 2007, Messrs. Cordes, Hyland and Shapiro were each granted 500 common units. The units were purchased from the NYSE on February 27, 2007 at a unit price of $36.61.

Item 12. Security Ownership of Certain Beneficial Owners and Management

The following table sets forth certain information, at February 15, 2008, as to the beneficial ownership of our common and subordinated units by beneficial holders of 5.0% or more of either such class of units, each member of our Board, each of the Named Executive Officers and all of our executive officers and directors as a group, based on data furnished by them:

Name of Beneficial Owner	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned (1)	Subordinated Units Beneficially Owned	Percentage of Subordinated Units Beneficially Owned (1)	Percentage of Total Equity Securities Beneficially Owned
Jamie L. Buskill	-	-	-	-	-
Brian A. Cody	-	-	-	-	-
William R. Cordes	500	*	-	-	-
John C. Earley Jr.	-	-	-	-	-
Rolf A. Gafvert	-	-	-	-	-
Thomas E. Hyland	6,000	*	-	-	-
Michael E. McMahon	-	-	-	-	-
Jonathan E. Nathanson	15,000	*	-	-	-
Arthur L. Rebell	39,083(2)	*	-	-	-
Mark L. Shapiro	11,000	*	-	-	-
Andrew H. Tisch	18,550(3)	*	-	-	-
All directors and executive officers as a group	90,133	*	-	-	-
BPHC (4)	53,256,122	58.75%	33,093,878	100.00%	70.38%
Loews Corporation (4)	53,256,122	58.75%	33,093,878	100.00%	70.38%

*Represents less than 1.0% of the outstanding common units

(1) As of February 15, 2008, we had 90,656,122 common units and 33,093,878 subordinated units issued and outstanding.

(2) 33,083 of these units are owned by Arebell, LLC, a limited liability company controlled by Mr. Rebell.

(3) Represents one quarter of the number of units owned by a general partnership in which a one-quarter interest is held by a trust of which Mr. Tisch is managing trustee.

(4) Loews Corporation is the parent company of BPHC and may, therefore, be deemed to beneficially own the units held by BPHC. The address of BPHC is 9 Greenway Plaza, Suite 2800, Houston, TX 77046. The address of Loews is 667 Madison Avenue, New York, New York 10065.

Securities Authorized for Issuance Under Equity Compensation Plans

In 2005, our Board adopted the Boardwalk Pipeline Partners, LP Long-Term Incentive Plan. The following table provides certain information as of December 31, 2007, with respect to this plan:

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plan (excluding securities reflected in the first column)
Equity compensation plans approved by security holders	-	N/A	-
Equity compensation plans not approved by security holders	-	N/A	3,522,500

Note 9 in Item 8 of this Report contains more information regarding our equity compensation plan.

Item 13. Certain Relationships and Related Transactions, and Director Independence

It is our Board's policy that any transaction, regardless of the size or amount involved, involving us or any of our subsidiaries in which any related person had or will have a direct or indirect material interest shall be reviewed by, and shall be subject to approval or ratification by our Audit Committee. "Related person" means our general partner and its directors and executive officers, holders of more than 5.0% of our units, and in each case, their "immediate family members," including any child, stepchild, parent, stepparent, spouse, sibling, mother-in-law, father-in-law, son-in-law, daughter-in-law, brother-in-law, or sister-in-law, and any person (other than a tenant or employee) sharing their household. In order to effectuate this policy, our General Counsel reviews all such transactions and reports thereon to the Audit Committee for its consideration. Our General Counsel also determines whether any such transaction presents a potential conflict of interest under our partnership agreement and, if so, presents the transaction to our Conflicts Committee for its consideration. See Note 1 and Note 14 in Item 8 of this Report for a description of certain related party transactions.

Our Independent Directors

Our Board has determined that Thomas E. Hyland, Mark L. Shapiro and William R. Cordes are independent directors under the listing standards of the NYSE. Our Board considered all relevant facts and circumstances and applied the independence guidelines described below in determining that none of these directors has any material relationship with us, our management, our general partner or its affiliates or our subsidiaries.

Our Board has established guidelines to assist it in determining director independence. Under these guidelines, a director would not be considered independent if any of the following relationships exists:

(i) during the past three years the director has been an employee, or an immediate family member has been an executive officer, of us;

(ii) the director or an immediate family member received, during any twelve month period within the past three years, more than $100,000 in direct compensation from us, excluding director and committee fees, pension payments and certain forms of deferred compensation;

(iii) the director is a current partner or employee or an immediate family member is a current partner of a firm that is our internal or external auditor, or an immediate family member is a current employee of such a firm and participates in the firm's audit, assurance or tax compliance (but not tax planning) practice or, within the last three years, the director or an immediate family member was a partner employee of such a firm and personally worked on our audit within that time;

(iv) the director or an immediate family member has at any time during the past three years been employed as an executive officer of another company where any of our present executive officers at the same time serves or served on that company's compensation committee; or

(v) the director is a current employee, or an immediate family member is a current executive officer, of a company that has made payments to, or received payments from, us for property or services in an amount which, in any of the last three years, exceeds the greater of $1.0 million, or 2.0% of the other company's consolidated gross revenues.

Our Board has appointed an Audit Committee comprised solely of independent directors. The NYSE does not require a listed limited partnership, or a listed company that is majority-owned by another listed company, such as us, to have a majority of independent directors on its board of directors or to maintain a compensation or nominating/corporate governance committee. In reliance on these exemptions, our Board is not comprised of a majority of independent directors, nor do we maintain a compensation or nominating/corporate governance committee.

Item 14. Principal Accounting Fees and Services

Audit Fees and Services

The following table presents fees billed by Deloitte & Touche LLP and its affiliates for professional services rendered to us and our subsidiaries in 2007 and 2006 by category as described in the notes to the table (in thousands):

	2007	2006
Audit fees (1)	$ 2,216	$ 1,513
Audit related fees (2)	514	553
Tax fees (3)	2	2
Total	$ 2,732	$ 2,068

(1) Includes the aggregate fees and expenses for annual financial statement audit and quarterly financial statements reviews.

(2) Includes the aggregate fees and expenses for services that were reasonably related to the performance of the financial statement audits or reviews described above and not included under "Audit Fees" above, including, principally, consents and comfort letters, audits of employee benefits plans, Sarbanes-Oxley implementation and other potential acquisitions.

(3) Includes the aggregate fees and expenses for tax professional education services.

Auditor Engagement Pre-Approval Policy

In order to assure the continued independence of our independent auditor, currently Deloitte & Touche LLP, the Audit Committee has adopted a policy requiring its pre-approval of all audit and non-audit services performed for us and our subsidiaries by the independent auditor. Under this policy, the Audit Committee annually pre-approves certain limited, specified recurring services which may be provided by Deloitte & Touche, subject to maximum dollar limitations. All other engagements for services to be performed by Deloitte & Touche must be specifically pre-approved by the Audit Committee, or a designated committee member to whom this authority has been delegated.

Since the formation of the Audit Committee and its adoption of this policy in November 2005, the Audit Committee, or a designated member, has pre-approved all engagements by us and our subsidiaries for services of Deloitte & Touche, including the terms and fees thereof, and the Audit Committee concluded that all such engagements were compatible with the continued independence of Deloitte & Touche in serving as our independent auditor.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) 1. Financial Statements

Included in Item 8 of this report:

Reports of Independent Registered Public Accounting Firm

Consolidated Balance Sheets at December 31, 2007 and 2006

Consolidated Statements of Income for the years ended December 31, 2007, 2006 and 2005

Consolidated Statements of Cash Flows for the years ended December 31, 2007, 2006 and 2005

Consolidated Statements of Changes in Member's Equity and Partners' Capital for the years ended December 31, 2007, 2006 and 2005

Consolidated Statements of Comprehensive Income for the years ended December 31, 2007, 2006 and 2005

Notes to Consolidated Financial Statements

(a) 2. Financial Statement Schedules

Valuation and Qualifying Accounts

The following table presents those accounts that have a reserve as of December 31, 2007, 2006 and 2005 and are not included in specific schedules herein. These amounts have been deducted from the respective assets on the Consolidated Balance Sheets (in thousands):

Description	Balance at Beginning of Period	Charged to Costs and Expenses	Other Additions (Recoveries)	Deductions (Write-offs)	Balance at End of Period
Allowance for doubtful accounts:					
2007	$ 2,610	$ 2,706	$ (4,657)	$ (226)	$ 433
2006	730	2,053	-	(173)	2,610
2005	174	745	(187)	(2)	730
Inventory obsolescence:					
2007	$ 33	$ -	$ 86	$ (33)	$ 86
2006	-	33	-	-	33
2005	201	-	11	(212)	-

(a) 3. Exhibits

The following documents are filed as exhibits to this report:

Exhibit Number	Description
3.1	Certificate of Limited Partnership of Boardwalk Pipeline Partners, LP (Incorporated by reference to Exhibit 3.1 to the Registrant's Registration Statement on Form S-1, Registration No. 333-127578, filed on August 16, 2005).
3.2	Second Amended and Restated Agreement of Limited Partnership of Boardwalk Pipeline Partners, LP dated as of September 19, 2006. (Incorporated by reference to Exhibit 3.1 to Boardwalk Pipeline Partners, LP Current Report on Form 8-K filed on September 25, 2006).
3.3	Certificate of Limited Partnership of Boardwalk GP, LP (Incorporated by reference to Exhibit 3.3 to the Registrant's Registration Statement on Form S-1, Registration No. 333-127578, filed on August 16, 2005).
3.4	Agreement of Limited Partnership of Boardwalk GP, LP (Incorporated by reference to Exhibit 3.4 to Amendment No. 1 to the Registrant's Registration Statement on Form S-1, Registration No. 333-127578, filed on September 22, 2005).
3.5	Certificate of Formation of Boardwalk GP, LLC (Incorporated by reference to Exhibit 3.5 to the Registrant's Registration Statement on Form S-1, Registration No. 333-127578, filed on August 16, 2005).
3.6	Amended and Restated Limited Liability Company Agreement (Incorporated by reference to Exhibit 3.6 to Amendment No. 4 to Registrant's Registration Statement on Form S-1, Registration No. 333-127578, filed on October 31, 2005).
10.1	Amended and Restated Revolving Credit Agreement, dated as of June 29, 2006, among Boardwalk Pipelines, LP, Boardwalk Pipeline Partners, LP, the several banks and other financial institutions or entities parties to the agreement as lenders, the issuers party to the agreement, Wachovia Bank, National Association., as administrative agent for the lenders and the issuers, Citibank, N.A., as syndication agent, JPMorgan Chase Bank, N.A., Deutsche Bank Securities, Inc. and Union Bank of California, N.A., as co-documentation agents, and Wachovia Capital Markets LLC and Citigroup Global Markets Inc., as joint lead arrangers and joint book managers (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on July 5, 2006).
10.2	Amendment No. 1 to Amended and Restated Revolving Credit Agreement, dated as of April 2, 2007, among the Registrant, Boardwalk Pipelines, LP, Texas Gas Transmission, LLC and Gulf South Pipeline Company, LP, each a wholly-owned subsidiary of the Registrant, as Borrowers, and the agent and lender parties identified therein (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on April 5, 2007).
10.3	Amendment No. 2 to Amended and Restated Revolving Credit Agreement, dated as of November 27, 2007, among the Registrant, Boardwalk Pipelines, LP, Texas Gas Transmission, LLC and Gulf South Pipeline Company, LP, and the agent and lender parties identified therein (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on November 29, 2007).
10.4	Contribution, Conveyance and Assumption Agreement, dated as of November 15, 2005, by and among Boardwalk Pipelines Holding Corp., Boardwalk GP, LLC, Boardwalk Pipeline Partners, LP, Boardwalk Operating GP, LLC, Boardwalk GP, LP, and Boardwalk Pipelines, LLC (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on November 18, 2005).
10.5	Indenture dated July 15, 1997, between Texas Gas Transmission Corporation (now known as Texas Gas Transmission, LLC) and The Bank of New York, as Trustee (Incorporated by reference to Exhibit 4.1 to Texas Gas Transmission Corporation's Registration Statement on Form S-3, Registration No. 333-27359, filed on May 19, 1997).
10.6	Indenture dated as of May 28, 2003, between TGT Pipeline, LLC and The Bank of New York, as Trustee (Incorporated by reference to Exhibit 3.6 to TGT Pipeline, LLC's (now known as Boardwalk Pipelines, LP) Registration Statement on Form S-4, Registration No. 333-108693, filed on September 11, 2003).

10.7	Indenture dated as of May 28, 2003, between Texas Gas Transmission, LLC and The Bank of New York, as Trustee (Incorporated by reference to Exhibit 3.5 to Boardwalk Pipelines, LLC's (now known as Boardwalk Pipelines, LP) Registration Statement on Form S-4, Registration No. 333-108693, filed on September 11, 2003).
10.8	Indenture dated as of January 18, 2005 between TGT Pipeline, LLC and The Bank of New York, as Trustee, (Incorporated by reference to Exhibit 10.1 to TGT Pipeline, LLC's (now known as Boardwalk Pipelines, LP) Current Report on Form 8-K filed on January 24, 2005).
10.9	Indenture dated as of January 18, 2005, between Gulf South Pipeline Company, LP and The Bank of New York, as Trustee (Incorporated by reference to Exhibit 10.2 to Boardwalk Pipelines, LLC's (now known as Boardwalk Pipelines, LP) Current Report on Form 8-K filed on January 24, 2005).
10.10	Indenture dated as of November 21, 2006, between Boardwalk Pipelines, LP, as issuer, the Registrant, as guarantor, and The Bank of New York Trust Company, N.A., as Trustee (Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed on November 22, 2006).
10.11	Indenture dated August 17, 2007 between Gulf South Pipeline Company, LP and the Bank of New York Trust Company, N.A. therein (Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed on August 17, 2007).
10.12	Indenture dated August 17, 2007 between Gulf South Pipeline Company, LP and the Bank of New York Trust Company, N.A. (Incorporated by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed on August 17, 2007).
10.13	Services Agreement, dated as of May 16, 2003 by and between Loews Corporation and Texas Gas Transmission, LLC. (Incorporated by reference to Exhibit 10.8 to Amendment No. 3 to the Registrant's Registration Statement on Form S-1, Registration No. 333-127578, filed on October 24, 2005). (1)
10.14	Boardwalk Pipeline Partners, LP Long-Term Incentive Plan (Incorporated by reference to Exhibit 10.9 to Amendment No. 4 to the Registrant's Registration Statement on Form S-1, Registration No. 333-127578, filed on October 31, 2005).
10.15	Form of Phantom Unit Award Agreement under the Boardwalk Pipeline Partners, LP Long-Term Incentive Plan (Incorporated by reference to Exhibit 10.10 to the Registrant's 2005 Annual Report on Form 10-K filed on March 16, 2006).
10.16	Boardwalk Pipeline Partners, LP Strategic Long Term Incentive Plan (Incorporated by reference to Exhibits 10.1 and 10.2 to the Registrant's Current Report on Form 8-K filed on July 28, 2006).
10.17	Form of GP Phantom Unit Award Agreement under the Boardwalk Pipeline Partners, LP Strategic Long Term Incentive Plan (Incorporated by reference to Exhibits 10.1 and 10.2 to the Registrant's Current Report on Form 8-K filed on July 28, 2006).
10.18	Letter Agreement, dated November 10, 2006, between Boardwalk Pipeline Partners, LP and Enterprise Gas Marketing L.P. (Incorporated by reference to Exhibit 10.1 to the Registrant's current Report on Form 8-K filed on November 14, 2006).
*21.1	List of Subsidiaries of the Registrant.
*23.0	Consent Of Independent Registered Public Accounting Firm
*31.1	Certification of, Rolf A. Gafvert, Chief Executive Officer, pursuant to Rule 13a-14(a) and Rule 15d-14(a).
*31.2	Certification of Jamie L. Buskill, Chief Financial Officer, pursuant to Rule 13a-14(a) and Rule 15d-14(a).
*32.1	Certification of Rolf A. Gafvert, Chief Executive Officer, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.2	Certification of Jamie L. Buskill, Chief Financial Officer, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith

(1) The Services Agreements between Gulf South Pipeline Company, LP and Loews Corporation and between Boardwalk Pipelines, LP (formerly known as Boardwalk Pipelines, LLC) and Loews Corporation are not filed because they are identical to exhibit 10.9 except for the identities of Gulf South Pipeline Company, LP and Boardwalk Pipelines, LLC and the date of the agreement.

SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Boardwalk Pipeline Partners, LP

By: Boardwalk GP, LP
its general partner

By: Boardwalk GP, LLC
its general partner

Dated: February 26, 2008

By: */s/ Jamie L. Buskill*_________
Jamie L. Buskill
Senior Vice-President, Chief Financial Officer and Treasurer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the date indicated.

Dated: February 26, 2008	*/s/ Rolf A. Gafvert* Rolf A. Gafvert President, Chief Executive Officer and Director (principal executive officer)
Dated: February 26, 2008	*/s/ Jamie L. Buskill* Jamie L. Buskill Senior Vice-President, Chief Financial Officer and Treasurer (principal financial officer)
Dated: February 26, 2008	*/s/ Steven A. Barkauskas* Steven A. Barkauskas Vice President, Controller and Chief Accounting Officer (principal accounting officer)
Dated: February 26, 2008	*/s/ William R. Cordes* William R. Cordes Director
Dated: February 26, 2008	*/s/ Thomas E. Hyland* Thomas E. Hyland Director
Dated: February 26, 2008	*/s/ Jonathan E. Nathanson* Jonathan E. Nathanson Director
Dated: February 26, 2008	*/s/ Arthur L. Rebell* Arthur L. Rebell Director
Dated: February 26, 2008	*/s/ Mark L. Shapiro* Mark L. Shapiro Director
Dated: February 26, 2008	*/s/ Andrew H. Tisch* Andrew H. Tisch Director

Section 2: EX-21.1 (EXHIBIT 21.1)

EXHIBIT 21.1

BOARDWALK PIPELINE PARTNERS, LP
Subsidiaries of the Registrant
December 31, 2007

Name of Subsidiary	Organized Under Laws of	Business Names
Boardwalk Operating GP, LLC	Delaware	
Boardwalk Pipelines, LP	Delaware	
Texas Gas Transmission, LLC	Delaware	Texas Gas
Gulf South Pipeline Company, LP	Delaware	Gulf South
GS Pipeline Company, LLC	Delaware	
Gulf Crossing Pipeline Company LLC	Delaware	Gulf Crossing

Section 3: EX-23.0 (EXHIBIT 23.0)

EXHIBIT 23.0

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-141058 on Form S-3 of our reports dated February 26, 2008, relating to the consolidated financial statements and consolidated financial statement schedule of Boardwalk Pipeline Partners, LP (which report expresses an unqualified opinion on the consolidated financial statements and consolidated financial statement schedule and includes an explanatory paragraph referring to a change in Boardwalk Pipeline Partners, LP's tax status) and the effectiveness of Boardwalk Pipeline Partners, LP's internal control over financial reporting, appearing in this Annual Report on Form 10-K of Boardwalk Pipeline Partners, LP for the year ended December 31, 2007.

DELOITTE & TOUCHE LLP
Chicago, Illinois
February 26, 2008

Section 4: EX-31.1 (EXHIBIT 31.1)

EXHIBIT 31.1

I, Rolf A. Gafvert, certify that:

1) I have reviewed this report on Form 10-K of Boardwalk Pipeline Partners, LP;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the consolidated financial statements, and other financial information included in this report, fairly present in all material respects the balance sheets, statements of income and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5) The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors :
   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Dated: February 26, 2008

/s/ Rolf A. Gafvert
Rolf A. Gafvert
President, Chief Executive Officer and Director

Section 5: EX-31.2 (EXHIBIT 31.2)

EXHIBIT 31.2

I, Jamie L. Buskill, certify that:

1) I have reviewed this report on Form 10-K of Boardwalk Pipeline Partners, LP;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the consolidated financial statements, and other financial information included in this report, fairly present in all material respects the balance sheets, statements of income and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5) The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors:
   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Dated: February 26, 2008

/s/ Jamie L. Buskill
Jamie L. Buskill
Senior Vice-President, Chief Financial Officer and Treasurer

Section 6: EX-32.1 (EXHIBIT 32.1)

EXHIBIT 32.1

Certification by the Chief Executive Officer
of
Boardwalk GP, LLC
pursuant to 18 U.S.C. Section 1350
(as adopted by Section 906 of the Sarbanes-Oxley Act of 2002)

Pursuant to 18 U.S.C. Section 1350, the undersigned chief executive officer of Boardwalk GP, LLC hereby certify, to such officer’s knowledge, that the annual report on Form 10-K for the year ended December 31, 2007, (the "Report") of Boardwalk Pipeline Partners, LP (the “Partnership”) fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

February 26, 2008

/s/ Rolf A. Gafvert
Rolf A. Gafvert
President, Chief Executive Officer and Director
(principal executive officer)

Section 7: EX-32.2 (EXHIBIT 32.2)

EXHIBIT 32.2

Certification by the Chief Financial Officer
of
Boardwalk GP, LLC
pursuant to 18 U.S.C. Section 1350
(as adopted by Section 906 of the Sarbanes-Oxley Act of 2002)

Pursuant to 18 U.S.C. Section 1350, the undersigned chief financial officer of Boardwalk GP, LLC hereby certifies, to such officer's knowledge, that the annual report on Form 10-K for the year ended December 31, 2007, (the "Report") of Boardwalk Pipeline Partners, LP (the "Partnership") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

February 26, 2008

/s/ *Jamie L. Buskill*
Jamie L. Buskill
Senior Vice-President, Chief Financial Officer and Treasurer
(principal financial officer)

Section 8: 10-K (PDF VERSION OF 10-K)

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EEP 10-Q 9/30/2008

Section 1: 10-Q (10-Q)

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended September 30, 2008

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission file number 1-10934

ENBRIDGE ENERGY PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

Delaware	**39-1715850**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

1100 Louisiana
Suite 3300
Houston, TX 77002
(Address of principal executive offices and zip code)

(713) 821-2000
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large Accelerated Filer ☒	Accelerated Filer ☐	Non-Accelerated Filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

The Registrant had 59,838,834 Class A common units outstanding as of October 31, 2008.

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ENBRIDGE ENERGY PARTNERS, L.P.

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In this report, unless the context requires otherwise, references to "we," "us," "our," or the "Partnership" are intended to mean Enbridge Energy Partners, L.P. and its consolidated subsidiaries. This Quarterly Report on Form 10-Q contains forward-looking statements. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. They use words such as "anticipate," "believe," "continue," "estimate," "expect," "forecast," "intend," "may," "plan," "position," "projection," "strategy," "could," "should," "would," or "will" or the negative of those terms or other variations of them or by comparable terminology. In particular, statements, expressed or implied, concerning future actions, conditions or events or future operating results or the ability to generate revenue, income or cash flow or to make distributions are forward-looking statements. Forward-looking statements are not guarantees of performance. They involve risks, uncertainties and assumptions. Future actions, conditions or events and future results of operations may differ materially from those expressed in these forward-looking statements. Many of the factors that will determine these results are beyond our ability to control or predict. For additional discussion of risks, uncertainties and assumptions, see "Risk Factors" included in Part I, Item 1A of our Annual Report on Form 10-K for the fiscal year ended December 31, 2007 and in Part II, Item 1A of our quarterly reports on Form 10-Q.

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PART I—FINANCIAL INFORMATION

Item 1. Financial Statements

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF INCOME

	Three months ended September 30,		Nine months ended September 30,	
	2008	2007	2008	2007
	(unaudited; in millions, except per unit amounts)			
Operating revenue	$2,812.7	$1,710.9	$8,180.2	$5,162.3
Operating expenses				
Cost of natural gas (Notes 10 and 11)	2,407.5	1,430.8	7,120.6	4,390.7
Operating and administrative	139.9	103.8	378.4	306.6
Power	35.0	29.7	104.6	87.1
Depreciation and amortization	58.6	45.0	163.1	121.3
	2,641.0	1,609.3	7,766.7	4,905.7
Operating income	171.7	101.6	413.5	256.6
Interest expense	50.7	23.4	129.7	70.2
Other income	0.3	0.4	2.5	2.3
Income before income tax expense	121.3	78.6	286.3	188.7
Income tax expense	1.9	1.3	5.0	3.7
Net income	$ 119.4	$ 77.3	$ 281.3	$ 185.0
Net income allocable to limited partner units (Note 2)	$ 105.3	$ 67.9	$ 245.5	$ 158.6
Net income per limited partner unit (basic and diluted) (Note 2)	$ 1.09	$ 0.75	$ 2.58	$ 1.87
Weighted average limited partner units outstanding	96.9	90.0	95.3	84.8

The accompanying notes are an integral part of these consolidated financial statements.

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ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Three months ended September 30,		Nine months ended September 30,	
	2008	2007	2008	2007
	(unaudited; in millions)			
Net income	$119.4	$77.3	$281.3	$185.0
Other comprehensive income (loss), net of tax benefit (expense) of $(1.5), $0, $(0.4) and $0.4 (Notes 10 and 11)	257.1	(1.6)	66.6	(36.6)
Comprehensive income	$376.5	$75.7	$347.9	$148.4

The accompanying notes are an integral part of these consolidated financial statements.

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ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Nine months ended September 30, 2008	Nine months ended September 30, 2007
	(unaudited; in millions)	
Cash provided by operating activities		
Net income	$ 281.3	$ 185.0
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	163.1	121.3
Derivative fair value (gains) losses (Notes 10 and 11)	(17.5)	17.4
Inventory market price adjustments (Note 4)	8.3	4.5
Other	20.1	(2.0)
Changes in operating assets and liabilities, net of cash acquired:		
Receivables, trade and other	(49.2)	42.3
Due from General Partner and affiliates	2.1	2.5
Accrued receivables	21.1	116.2
Inventory (Note 4)	(98.6)	(13.6)
Current and long term other assets (Notes 10 and 11)	(9.1)	(5.4)
Due to General Partner and affiliates (Note 8)	35.4	39.1
Accounts payable and other (Notes 3, 10 and 11)	(10.5)	(5.9)
Accrued purchases	78.1	(116.8)
Interest payable	55.9	28.9
Property and other taxes payable	14.8	5.3
Settlement of interest rate derivatives (Note 11)	(22.1)	(0.9)
Net cash provided by operating activities	473.2	417.9
Cash used in investing activities		
Additions to property, plant and equipment	(1,000.2)	(1,428.4)
Changes in construction payables	(56.0)	56.4
Changes in restricted cash (Note 3)	(10.0)	—
Other	(13.0)	(2.0)
Net cash used in investing activities	(1,079.2)	(1,374.0)
Cash provided by financing activities		
Net proceeds from unit issuances (Note 7)	221.8	628.8
Distributions to partners (Note 7)	(211.8)	(179.5)
Net borrowings (repayments) under Credit Facility (Note 6)	(13.7)	120.0
Net repayments of commercial paper (Note 6)	(79.4)	(241.2)
Net proceeds from issuances of long-term debt (Note 6)	790.2	592.8
Net cash provided by financing activities	707.1	920.9
Net increase (decrease) in cash and cash equivalents	101.1	(35.2)
Cash and cash equivalents at beginning of year	50.5	184.6
Cash and cash equivalents at end of period	$ 151.6	$ 149.4

The accompanying notes are an integral part of these consolidated financial statements.

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ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	September 30, 2008	December 31, 2007
	(unaudited; dollars in millions)	
ASSETS		
Current assets		
Cash and cash equivalents (Note 3)	$ 151.6	$ 50.5
Restricted cash (Note 3)	10.0	—
Receivables, trade and other, net of allowance for doubtful accounts of $2.0 in 2008 and $1.9 in 2007	208.3	157.8
Due from General Partner and affiliates	25.1	27.2
Accrued receivables	577.7	598.8
Inventory (Note 4)	200.9	110.6
Other current assets (Notes 10 and 11)	14.2	14.8
	1,187.8	959.7
Property, plant and equipment, net (Note 5)	6,406.6	5,554.9
Goodwill	256.5	256.5
Intangibles, net	89.7	91.5
Other assets, net (Notes 10 and 11)	40.5	29.0
	$ 7,981.1	$ 6,891.6
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Due to General Partner and affiliates (Note 8)	$ 102.3	$ 45.8
Accounts payable and other (Notes 3, 9, 10 and 11)	271.5	400.4
Accrued purchases	681.9	603.8
Interest payable	76.8	20.9
Property and other taxes payable	37.3	22.5
Current maturities of long term debt	442.8	31.0
	1,612.6	1,124.4
Long term debt (Note 6)	3,163.5	2,862.9
Notes payable to affiliate	130.0	130.0
Other long-term liabilities (Notes 9, 10 and 11)	145.6	202.8
	5,051.7	4,320.1
Commitments and contingencies (Note 9)		
Partners' capital (Note 7)		
Class A common units (59,838,834 at September 30, 2008 and 55,238,834 at December 31, 2007)	1,529.1	1,340.7
Class B common units (3,912,750 at September 30, 2008 and December 31, 2007)	77.6	72.9
Class C units (19,158,153 at September 30, 2008 and 18,073,367 at December 31, 2007)	921.3	874.1
i-units (14,355,600 at September 30, 2008 and 13,564,086 at December 31, 2007)	557.8	515.3
General Partner	71.4	62.9
Accumulated other comprehensive loss (Notes 10 and 11)	(227.8)	(294.4)
	2,929.4	2,571.5
	$ 7,981.1	$ 6,891.6

The accompanying notes are an integral part of these consolidated financial statements.

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ENBRIDGE ENERGY PARTNERS, L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

1. BASIS OF PRESENTATION

The accompanying unaudited interim consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America for interim consolidated financial information and with the instructions to Form 10-Q and Rule 10-01 of Regulation S-X. Accordingly, they do not include all the information and footnotes required by accounting principles generally accepted in the United States of America for complete consolidated financial statements. In the opinion of management, they contain all adjustments, consisting only of normal recurring adjustments, which management considers necessary to present fairly our financial position as of September 30, 2008 and December 31, 2007; the results of operations for the three and nine month periods ended September 30, 2008 and 2007; and our cash flows for the nine month periods ended September 30, 2008 and 2007. We derived the Consolidated Statement of Financial Position as of December 31, 2007, from the audited financial statements included in our 2007 Annual Report on Form 10-K. The results of operations for the three and nine month periods ended September 30, 2008, should not be taken as indicative of the results to be expected for the full year due to seasonality of portions of the natural gas business, timing and completion of our construction projects, maintenance activities and the impact of forward natural gas prices and differentials on certain derivative financial instruments that are accounted for using mark-to-market accounting. Our interim consolidated financial statements should be read in conjunction with our consolidated financial statements and notes thereto presented in our Annual Report on Form 10-K for the fiscal year ended December 31, 2007.

Comparative Amounts

We have made reclassifications to the amounts reported in our prior year consolidated statement of financial position and our consolidated statements of cash flows to conform to our current year presentation. We reclassified $2.8 million of "Environmental liabilities" to "Other long-term liabilities" in our December 31, 2007 consolidated statement of financial position. We also reclassified $1.8 million for changes in "Environmental liabilities" to "Other" under the operating section of our consolidated statements of cash flows. In addition, we reclassified $3.5 million for changes in the balance of "Current income tax payable" to "Property and other taxes payable" on our consolidated statements of cash flows.

2. NET INCOME PER LIMITED PARTNER UNIT

Net income per limited partner unit is computed by dividing net income, after we deduct our allocations to our general partner, Enbridge Energy Company, Inc. (the "General Partner"), by the weighted average number of our limited partner units outstanding. The General Partner's allocation is equal to an amount based upon its general partner interest, adjusted to reflect an amount equal to its incentive distributions and an amount required to reflect depreciation on the General Partner's historical

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ENBRIDGE ENERGY PARTNERS, L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited) (Continued)

cost basis for assets contributed on formation of the Partnership. We have no dilutive securities. Net income per limited partner unit was determined as follows:

	Three months ended September 30,		Nine months ended September 30,	
	2008	2007	2008	2007
	(unaudited; in millions, except per unit amounts)			
Net income	$ 119.4	$ 77.3	$ 281.3	$ 185.0
Allocations to the General Partner:				
Net income allocated to the General Partner	(2.4)	(1.5)	(5.6)	(3.7)
Incentive distributions allocated to the General Partner	(11.7)	(7.9)	(30.1)	(22.6)
Historical cost depreciation adjustments	—	—	(0.1)	(0.1)
	(14.1)	(9.4)	(35.8)	(26.4)
Net income allocable to limited partner units	$ 105.3	$ 67.9	$ 245.5	$ 158.6
Net income per limited partner unit (basic and diluted)	$ 1.09	$ 0.75	$ 2.58	$ 1.87
Weighted average limited partner units outstanding	96.9	90.0	95.3	84.8

3. CASH AND CASH EQUIVALENTS

We extinguish liabilities when a creditor has relieved us of our obligation, which occurs when our financial institution honors a check that the creditor has presented for payment. Accordingly, obligations for which we have issued check payments that have not yet been presented to the financial institution in the amounts of approximately $33.4 million at September 30, 2008 and $38.5 million at December 31, 2007, are included in "Accounts payable and other" on our consolidated statements of financial position.

In September 2008, following the bankruptcy filing by Lehman Brothers Bank, FSB, as discussed in Note 6, Bank of America, N.A., as administrative agent to our Credit Facility, required us to post a certificate of deposit issued by Bank of America, N.A. for $10.0 million as collateral against the letters of credit outstanding on our Credit Facility, which we have presented as "Restricted cash" on our consolidated statements of financial position.

4. INVENTORY

Inventory is comprised of the following:

	September 30, 2008	December 31, 2007
	(in millions)	
Materials and supplies	$ 3.9	$ 3.9
Liquids inventory	27.7	6.7
Natural gas and natural gas liquids inventory	169.3	100.0
	$ 200.9	$ 110.6

The cost of natural gas on our consolidated statements of income includes charges totaling $8.3 million for the three and nine months ended September 30, 2008 and $4.5 million for the three and nine months ended September 30, 2007 that we recorded to reduce the cost basis of our natural gas inventory to reflect market value.

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ENBRIDGE ENERGY PARTNERS, L.P.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited) (Continued)

5. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment is comprised of the following:

	September 30, 2008	December 31, 2007
	(in millions)	
Land	$ 17.6	$ 14.3
Rights-of-way	417.5	345.8
Pipelines	4,167.7	2,703.2
Pumping equipment, buildings and tanks	984.9	854.7
Compressors, meters, and other operating equipment	616.2	536.1
Vehicles, office furniture and equipment	151.9	123.3
Processing and treating plants	297.9	200.4
Construction in progress	943.6	1,813.9
Total property, plant and equipment	7,597.3	6,591.7
Accumulated depreciation	(1,190.7)	(1,036.8)
Property, plant and equipment, net	$ 6,406.6	$ 5,554.9

6. DEBT

Credit Facility

In March 2008, we requested and received approval from the parties named as lenders to our Credit Facility for a one year extension of the maturity date from April 4, 2012 to April 4, 2013.

At September 30, 2008, we had $386.2 million outstanding under our Credit Facility at a weighted average interest rate of 3.82% and letters of credit totaling $101.2 million. The amounts we may borrow under the terms of our Credit Facility are reduced by the principal amount of our commercial paper issuances and the balance of our letters of credit outstanding. The terms of our Credit Facility include commitments from 14 different lenders to borrow up to $1,250 million, at September 30, 2008. One of the committed lenders to our Credit Facility, Lehman Brothers Bank, FSB ("Lehman BB"), a subsidiary of Lehman Brothers Holdings, Inc. filed for bankruptcy protection under Chapter 11 of the United States ("U.S.") Bankruptcy Code in September 2008. Lehman BB has commitments of $82.5 million that we currently cannot access; effectively reducing the amounts available to us under our Credit Facility to $1,167.5 million. We are working with other financial institutions to assume Lehman BB's commitment. The remaining lenders under our Credit Facility continue to honor our funding requests.

Excluding the commitments from Lehman BB, at September 30, 2008, we could borrow $490.1 million under the terms of our Credit Facility, determined as follows:

		September 30, 2008
		(in millions)
Total credit available under Credit Facility		$ 1,250.0
Less:	Amounts outstanding under Credit Facility	(386.2)
	Balance of letters of credit outstanding	(101.2)
	Principal amount of commercial paper issuances	(190.0)
	Lehman Brothers Bank, FSB commitment	(82.5)
Total amount we could borrow at September 30, 2008		$ 490.1

Individual borrowings under the terms of our Credit Facility generally become due and payable at the end of each contract period, which typically is a period of three months or less. We have the option to

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NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited) (Continued)

repay these amounts on a non-cash basis by net settling with the parties to our Credit Facility by contemporaneously borrowing at the then current rate of interest and repaying the amounts due. During the nine months ended September 30, 2008, we net settled borrowings of approximately $490 million on a non-cash basis.

Commercial Paper Program

We have a commercial paper program that provides for the issuance of up to $600 million of commercial paper that is supported by our Credit Facility. We access the commercial paper market primarily to provide temporary financing for our operating activities, capital expenditures and acquisitions, at rates that are generally lower than the rates available under our Credit Facility. At September 30, 2008 and December 31, 2007, respectively, we had $189.5 million and $268.5 million of commercial paper outstanding, net of unamortized discount of $0.5 million and $1.5 million, at weighted average interest rates of 3.19% and 5.36%. At September 30, 2008 we could issue an additional $410 million in principal amount under our commercial paper program. The commercial paper we can issue is limited by the credit available under our Credit Facility.

We have the ability and intent to refinance all of our commercial paper obligations on a long-term basis under our unsecured long-term Credit Facility. Accordingly, such amounts have been classified as long-term debt in our accompanying consolidated statements of financial position.

Senior Notes

In April 2008, we issued and sold in a private offering $400 million in principal amount of our 6.5% Notes due April 15, 2018 and $400 million in principal amount of our 7.5% Notes due April 15, 2038, which we collectively refer to as the Notes. We received net proceeds from the offering of approximately $790.2 million after initial purchasers' discounts and payment of offering expenses. We used a portion of the proceeds we received from this offering to repay outstanding issuances of commercial paper and borrowings under our Credit Facility that we had previously used to finance a portion of our capital expansion projects. We temporarily invested the remaining proceeds which we later used to fund additional expenditures under our capital expansion programs. The Notes do not contain any covenants restricting our issuance of additional indebtedness and rank equally with all of our other existing and future unsecured and unsubordinated indebtedness. Interest on the Notes is payable April 15th and October 15th of each year and we may redeem the Notes for cash in whole or in part at any time, at our option.

In August 2008, we completed the offers to exchange all of the Notes, which had not been registered under the Securities Act of 1933, as amended (the "Securities Act"), for notes with identical terms that had been registered under the Securities Act.

We received tenders for $395 million in aggregate principal amount of our outstanding $400 million of 6.50% Series A Notes due 2018, which we exchanged for $395 million of our 6.50% Series B Notes due 2018. We also received tenders for all $400 million in aggregate principal amount of our 7.50% Series A Notes due 2038, which we exchanged for $400 million of our 7.50% Series B Notes due 2038.

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7. PARTNERS' CAPITAL

The following table sets forth the distributions, as approved by the Board of Directors of Enbridge Energy Management, L.L.C. ("Enbridge Management") during the nine months ended September 30, 2008:

Distribution Declaration Date	Distribution Payment Date	Record Date	Distribution per Unit	Cash available for distribution	Amount of Distribution of i-units to i-unit Holders[1]	Amount of Distribution of Class C units to Class C unit Holders[2]	Retained from General Partner[3]	Distribution of Cash
July 28, 2008	August 14, 2008	August 6, 2008	$ 0.990	$ 108.0	$ 13.9	$ 18.6	$ 0.7	$ 74.8
April 28, 2008	May 15, 2008	May 7, 2008	$ 0.950	$ 102.2	$ 13.1	$ 17.5	$ 0.6	$ 71.0
January 28, 2008	February 14, 2008	February 6, 2008	$ 0.950	$ 96.7	$ 12.9	$ 17.2	$ 0.6	$ 66.0

(1) During 2008, in lieu of cash distributions, the Partnership issued 791,514 i-units to Enbridge Management.

(2) During 2008, in lieu of cash distributions, the Partnership issued 1,084,787 Class C units to our Class C unitholders.

(3) The Partnership retains an amount equal to 2 percent of the i-unit and Class C unit distribution from the General Partner in respect of its 2 percent general partner interest.

Issuance of Class A Common Units

On March 3, 2008, we issued and sold 4.6 million Class A common units, including 0.6 million units from the over-allotment option that was exercised by the underwriters, at a price to the public of $49.00 per unit, for proceeds of approximately $217.2 million, net of underwriters' discounts, commissions and issuance costs. In addition, our general partner contributed approximately $4.6 million to us to maintain its two percent general partner interest. We used the proceeds from this offering to partially reduce outstanding commercial paper we issued and amounts we previously borrowed under our Credit Facility to finance a portion of our capital expansion projects. We invested a portion of the proceeds for use in future periods to fund additional expenditures under our capital expansion projects.

8. RELATED PARTY TRANSACTIONS

We, our general partner and Enbridge Pipelines Inc. ("Enbridge Pipelines"), a subsidiary of Enbridge Inc., regularly collaborate on construction projects that are mutually beneficial to our respective customers and operations. Examples of such projects include the Southern Access and Alberta Clipper projects where we are constructing the United States portion of the projects and Enbridge Pipelines is constructing the Canadian portion. In September 2008, we acquired for $21.1 million, approximately 22 miles of 36 inch diameter line pipe from our general partner for our use in constructing the Alberta Clipper project. The line pipe was initially obtained by our general partner for use in constructing the Southern Access extension, which has been delayed due to a protracted regulatory process.

9. COMMITMENTS AND CONTINGENCIES

Environmental Liabilities

We are subject to federal and state laws and regulations relating to the protection of the environment. Environmental risk is inherent to liquid hydrocarbon and natural gas pipeline operations and we could, at times, be subject to environmental cleanup and enforcement actions. We manage this environmental risk through appropriate environmental policies and practices to minimize any impact our operations may have on the environment. To the extent that we are unable to recover environmental liabilities associated with the Lakehead system assets through insurance, the General Partner has agreed to indemnify us from and against any costs relating to environmental liabilities associated with the Lakehead system assets prior to the transfer to us in 1991. This excludes any liabilities resulting from a change in laws after such transfer. We continue to voluntarily investigate past leak sites on our systems for the purpose of assessing whether

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any remediation is required in light of current regulations, and to date, no material environmental risks have been identified.

In October of 2008, we received a letter from the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration ("PHMSA") alleging violations of federal pipeline safety regulations and proposing a $2.4 million fine related to an unexpected release and fire on line 3 of our Lakehead System that occurred during planned maintenance near our Clearbrook, Minnesota, terminal in November 2007. A provision for the amount of the fine has been made in "Short term environmental liabilities."

As of September 30, 2008 and December 31, 2007, we have recorded $5.7 million and $3.4 million, respectively, in "Accounts payable and other" and $3.0 million and $2.8 million, respectively, in "Other long-term liabilities," primarily to address remediation of contaminated sites, asbestos containing materials, management of hazardous waste material disposal, outstanding air quality measures for certain of our liquids and natural gas assets, and penalties we have been or expect to be assessed.

Legal Proceedings

We are a participant in various legal proceedings arising in the ordinary course of business. Some of these proceedings are covered, in whole or in part, by insurance. We believe that the outcome of all these proceedings will not, individually or in the aggregate, have a material adverse effect on our financial condition.

10. FAIR VALUE MEASUREMENTS

We adopted the provisions of Statement of Financial Accounting Standards No. 157, *Fair Value Measurement*, or SFAS No. 157, as of January 1, 2008. SFAS No. 157 provides guidance for determining fair value and requires increased disclosure regarding the inputs to valuation techniques used to measure fair value. SFAS No. 157 defines fair value as an exit price representing the expected amount we would receive to sell an asset or pay to transfer a liability in an orderly transaction with market participants at the measurement date. We apply the provisions of SFAS No. 157 to fair values we report for our derivative instruments and annual disclosures associated with the fair values of our outstanding indebtedness.

We utilize a mid-market pricing convention for valuation as a practical expedient for assigning fair value to our derivative assets and liabilities. In the case of our liabilities, our nonperformance risk is considered in the valuation, based upon the ratings assigned to our debt obligations by the nationally recognized statistical ratings organizations. We present the fair value of our derivative contracts net of cash paid or received pursuant to collateral agreements on a net-by-counterparty basis in our consolidated statements of financial position when we believe a legal right of setoff exists under an enforceable netting agreement. Our credit exposure for over-the-counter derivatives is directly with our counterparty and continues until the maturity or termination of the contracts. When appropriate, valuations are adjusted for various factors such as credit and liquidity considerations.

We consider credit and nonperformance risk in our valuation of derivative contracts categorized in Level 1, 2 and 3, including both historical and current market data in our assessment of credit and nonperformance risk. We estimate a credit reserve for our outstanding derivative assets and liabilities at an individual transaction level in conjunction with the provisions of our master netting arrangements. Our assessment of credit and nonperformance risk did not affect our determination of the fair value of these derivative assets and liabilities. Likewise, no reserves were made in determining the fair value of our outstanding liabilities as a result of our own credit standing.

SFAS No. 157 establishes a hierarchy which prioritizes the inputs we use to measure fair value into three distinct categories based upon whether such inputs are observable in active markets or unobservable. We classify assets and liabilities in their entirety based on the lowest level of input that is significant to the fair value measurement. Our methodology for categorizing assets and liabilities that are measured at fair

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value pursuant to this hierarchy gives the highest priority to unadjusted quoted prices in active markets and the lowest level to unobservable inputs as outlined below:

- Level 1—We include in this category the fair value of assets and liabilities that we measure based on unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. We consider active markets as those in which transactions for the assets or liabilities occur with sufficient frequency and volume to provide pricing information on an ongoing basis. The fair value of our assets and liabilities included in this category consists primarily of exchange-traded derivative instruments.

- Level 2—We categorize the fair value of assets and liabilities that we measure with either directly or indirectly observable inputs as of the measurement date where pricing inputs are other than quoted prices in active markets as Level 2. This category includes those derivative instruments that we value using models or other valuation methodologies derived from observable market data. These models are primarily industry-standard models that consider various inputs including: (a) quoted forward prices for commodities, (b) time value, (c) volatility factors, and (d) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these inputs are observable in the marketplace throughout the full term of the derivative instrument, can be derived from observable data, or supported by observable levels at which transactions are executed in the marketplace.

- Level 3—We include in this category the fair value of assets and liabilities that we measure based on prices or valuation techniques that require inputs which are both significant to the fair value measurement and less observable from objective sources (i.e., supported by little or no market activity). We may also use these inputs with internally developed methodologies that result in our best estimate of the fair value. Level 3 instruments primarily include derivative instruments for which we do not have sufficient corroborating market evidence, such as binding broker quotes, to support classifying the asset or liability as Level 2. In most instances, the observable data is available for us to validate the inputs used to measure fair value; however, the cost of obtaining the information is prohibitive.

Derivative contracts can be exchange-traded or over-the counter ("OTC") traded. We generally value exchange-traded derivatives within portfolios calibrated to market clearing levels on a daily basis. We value OTC derivatives using broker information based on executed market transactions that we have corroborated with other observable market data. For OTC derivatives that trade in liquid markets, such as generic forwards, swaps, and options, inputs can generally be verified and valuation does not involve significant management judgment.

Certain OTC derivatives trade in less liquid markets with limited pricing information, and the determination of fair value for these derivatives is inherently more difficult. Such instruments are classified within Level 3 of the fair value hierarchy. We include the fair value of financial assets and liabilities in Level 3 as a default due to limited market data or in most cases, due to lacking binding broker quotes to corroborate pricing data as required by current interpretations of SFAS No. 157 Level 2 requirements. Financial assets and liabilities that are categorized in Level 3 may later be reclassified to the Level 2 category at the point we are able to obtain sufficient binding market data or the interpretation of Level 2 criteria is modified in practice to include non-binding market corroborated data.

The following table sets forth by level within the fair value hierarchy, our financial assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2008. We classify financial assets and liabilities in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement

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requires judgment, and may affect the valuation of the financial assets and liabilities and their placement within the fair value hierarchy.

Recurring fair value measures	Fair Value at September 30, 2008 Level 1	Level 2	Level 3	Total
		(in millions)		
Assets:				
Derivative instruments, net	$ —	$ —	$ 12.7	$ 12.7
Liabilities:				
Derivative instruments, net	(157.6)	—	(95.5)	(253.1)
Total	$(157.6)	$ —	$(82.8)	$(240.4)

The table below provides a summary of changes in the fair value of our Level 3 financial assets and liabilities for the nine months ended September 30, 2008. As reflected in the table, the net unrealized gain on Level 3 financial assets and liabilities was $4.6 million for the nine months ended September 30, 2008, which resulted from forward price decreases in natural gas, natural gas liquids, or NGLs, and crude oil derivative instruments that we held at September 30, 2008.

	Derivative Instruments, net
	(in millions)
Balance at January 1, 2008	$ (160.6)
Realized and unrealized net gains	79.3
Purchases and settlements	(1.5)
Transfer in (out) of Level 3	—
Balance at September 30, 2008	$ (82.8)
Change in unrealized net gains relating to instruments still held at September 30, 2008	$ 4.6

11. DERIVATIVE FINANCIAL INSTRUMENTS

Our net income and cash flows are subject to volatility stemming from changes in commodity prices of natural gas, NGLs, condensate and fractionation margins (the relative price differential between NGL sales and the offsetting natural gas purchases). Our exposure to commodity price risk exists within our Natural Gas and Marketing segments. We use derivative instruments including futures, forwards, swaps, options and other financial instruments with similar characteristics to manage the risks associated with market fluctuations in commodity prices, as well as to reduce the volatility of our cash flows. Our formal hedging program provides a control structure and governance for our hedging activities specific to identified risks and time periods, which are subject to the approval and monitoring by a committee of senior management. Based on our risk management policies, all of our derivative instruments are employed in connection with an underlying asset, liability and/or forecasted transaction and are not entered into with the objective of speculating on interest rates or commodity prices. We have hedged a portion of our exposure to the variability in future cash flows associated with forecasted natural gas and NGL sales and purchases through 2013 in accordance with our risk management policies.

Accounting Treatment

We record all derivative instruments in our consolidated financial statements at fair value pursuant to the provisions of Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities*, or SFAS No. 133, and the guidance set forth in SFAS No. 157 as discussed in Note 10 above. We adjust our consolidated financial statements each period for changes in the fair value of our derivative instruments, which we refer to as "marking to market" or "mark-to-market." For those derivative instruments that do not qualify for hedge accounting, we record all changes in fair market value through our consolidated statements of income each period.

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Under the guidance of SFAS No. 133, if a derivative instrument does not qualify as a hedge, or is not designated as a hedge, the derivative instrument is adjusted to its fair value each period with the increases and decreases in fair value recorded in our consolidated statements of income as increases and decreases in "Cost of natural gas" for our commodity-based derivatives. Our cash flow is only impacted to the extent the actual derivative contract is settled by making or receiving a payment to or from the counterparty or by making or receiving a payment for entering into a contract that exactly offsets the original derivative contract. Typically, we settle our derivative contracts when the physical transaction that underlies the derivative instrument occurs.

If a derivative instrument qualifies and is designated as a cash flow hedge, a hedge of a forecasted transaction or future cash flows, any unrealized mark-to-market gain or loss is deferred in "Accumulated other comprehensive income" ("AOCI"), a component of "Partners' capital," until the underlying hedged transaction occurs. To the extent that the hedge instrument is effective in offsetting the transaction being hedged, there is no impact to the income statement. At inception and on a quarterly basis, we formally assess whether the hedge contract is highly effective in offsetting changes in cash flows of hedged items. Any ineffective portion of a cash flow hedge's change in fair value is recognized each period in earnings. Realized gains and losses on derivative instruments that are designated as hedges and qualify for hedge accounting are included in "Cost of natural gas" in the period the hedged transaction occurs. Gains and losses deferred in AOCI related to cash flow hedges, for which hedge accounting has been discontinued, remain in AOCI until the underlying physical transaction occurs unless it is probable that the forecasted transaction will not occur by the end of the originally specified time period, or within an additional two-month period of time thereafter. Generally, our preference is for our derivative instruments to receive hedge accounting treatment whenever possible, to mitigate the non-cash earnings volatility that arises from recording the changes in fair value of our derivative instruments through earnings. To qualify for cash flow hedge accounting as set forth in SFAS No. 133, very specific requirements must be met in terms of hedge structure, hedge objective and hedge documentation. Additionally, both the counterparty credit standing and the ability to perform must be considered for both the hedge transaction and the physical transaction being hedged.

Non-Qualified Hedges

Many of our derivative instruments qualify for hedge accounting treatment under the specific requirements of SFAS No. 133. However, we have four primary transaction types associated with our commodity derivative instruments where the hedge structure does not meet the requirements to apply hedge accounting. As a result, these derivative instruments do not qualify for hedge accounting under SFAS No. 133 and are referred to as "non-qualified." Non-qualified derivative instruments are marked-to-market each period with the change in fair value, representing unrealized gains and losses, included in "Cost of natural gas" in our consolidated statements of income. These mark-to-market adjustments produce a degree of earnings volatility that can often be significant from period to period, but have no cash flow impact relative to changes in market prices. The cash flow impact occurs when the underlying physical transaction takes place in the future and when the associated derivative instrument contract settlement is made.

The four primary transaction types that do not qualify for hedge accounting are as follows:

1. **Transportation**—In our Marketing segment, when we transport natural gas from one location to another, the pricing index used for natural gas sales is generally different from the pricing index used for natural gas purchases, exposing us to basis price risk relative to changes in those two indices. By entering into a basis swap, we can effectively lock in the margin, or "spread," representing the difference between the sales price and the purchase price, on the combined natural gas purchase and natural gas sale, thereby removing locational price risk on the physical transactions. Although this represents a sound economic hedging strategy, the derivative instruments (i.e., the basis swaps) associated with these transportation contracts do not qualify for

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hedge accounting under SFAS No. 133, since only the future margin has been fixed and not the future cash flow. As a result, the changes in fair value of these derivative instruments are recorded in earnings.

2. **Storage**—In our Marketing segment, we use derivative instruments (i.e., natural gas swaps) to hedge the "margin," representing the relative difference between the injection price paid to purchase and store natural gas and the withdrawal price at which the natural gas is sold from storage. The intent of these derivative instruments is to lock in the margin between storage injections and withdrawals in a future period. We do not pursue cash flow hedge accounting treatment for these storage transactions since the underlying forecasted injection or withdrawal of natural gas may not occur in the period as originally forecast. This can occur because we retain the flexibility to make changes in the underlying injection or withdrawal schedule, given changes in market conditions. In addition, since the physical natural gas is recorded at the lower of cost or market, timing differences can result when the derivative instrument is settled in a period that is different from when the physical natural gas is sold from storage. As a result, derivative financial instruments associated with our natural gas storage activities can create volatility in our earnings.

3. **Natural Gas Collars**—In our Natural Gas segment, we had previously entered into natural gas collars to hedge the sales price of natural gas. The natural gas collars were based on a New York Mercantile Exchange ("NYMEX") price, while the physical gas sales were based on a different index. To better align the index of the natural gas collars with the index of the underlying sales, we de-designated the original cash flow hedging relationship with the intent of contemporaneously re-designating the natural gas collars as hedges of forecasted physical natural gas sales with a NYMEX pricing index. However, because the fair value of these derivative instruments was a liability to us at re-designation, they are considered net written options under SFAS No. 133 and do not qualify for hedge accounting. The changes in fair value of these derivative instruments from the date of de-designation are recorded in earnings each period. As a result, our operating income will be subject to greater volatility due to movements in the prices of natural gas until the underlying long-term transactions are settled.

4. **Optional Natural Gas Processing Volumes**—In our Natural Gas segment we use derivative instruments to hedge NGL volumes produced from our natural gas processing facilities. Many of our natural gas contracts provide us with the option of processing natural gas when it is economical, and allow us to cease processing when the "fractionation spread," representing the relative difference between the price received for the NGLs produced less the cost of natural gas used for processing, becomes uneconomic. We have entered into derivative instruments to fix the sales price of a portion of the NGLs that we produce at our discretion and to fix the associated purchases of natural gas required for processing when it is probable the processing will occur. Because our processing forecasts fluctuate due to market conditions, these derivative instruments are deemed "non-qualifying" hedges. For this reason, our operating income will be subject to increased volatility due to fluctuations in both natural gas and NGL prices until the underlying transactions are settled.

In each of the instances described above, the underlying physical purchase, storage and sale of natural gas and NGLs are accounted for on a historical cost or market basis rather than on the mark-to-market basis we utilize for the derivative instruments employed to mitigate the commodity price risk associated with our storage and transportation assets. This difference in accounting treatment between the derivative instrument and the underlying transaction (i.e., the derivative instruments are recorded at fair value while the physical transactions are recorded at historical cost) can and has resulted in volatility in our reported net income, even though the economic margin is essentially unchanged from the date the transactions were consummated.

The following table presents the unrealized gains and losses associated with changes in the fair value of our derivative instruments, which are recorded as an element of "Cost of natural gas" for our

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commodity-based derivative instruments in our consolidated statements of income and disclosed as a reconciling item on our consolidated statements of cash flows:

Derivative fair value gains (losses)	Three months ended September 30, 2008	Three months ended September 30, 2007	Nine months ended September 30, 2008	Nine months ended September 30, 2007
	(in millions)			
Natural Gas segment				
Hedge ineffectiveness	$ 0.1	$ (0.5)	$ (1.1)	$ (0.2)
Non-qualified hedges	36.5	(7.2)	42.5	(13.2)
Marketing segment				
Non-qualified hedges	11.0	2.9	(23.9)	(4.0)
Derivative fair value gains (losses)	$ 47.6	$ (4.8)	$ 17.5	$ (17.4)

De-designation and Settlement of Derivatives

We record the change in fair value of our cash flow hedges in AOCI until the derivative instruments are settled, at which time they are reclassified from AOCI to earnings. Also included in AOCI at September 30, 2008 are unrecognized losses of approximately $1.6 million associated with cash flow hedges that were subsequently de-designated. These losses are reclassified to earnings over the periods during which the originally hedged forecasted transactions affect earnings. For the three and nine months ended September 30, 2008, we reclassified losses of $52.1 million and $112.4 million, respectively, from AOCI to "Cost of natural gas" on our consolidated statements of income for the fair value of derivative instruments that were settled.

In connection with our April 2008 issuance and sale of $800 million in principal amount of Notes, we paid $22.1 million to settle treasury locks we entered to hedge the interest payments on a portion of these obligations through the maturity date of the Notes maturing in 2038. The $22.1 million is being amortized from AOCI to "Interest expense" over the 30-year term of the Notes.

Derivative Positions

Our derivative financial instruments are included at their fair values in our consolidated statements of financial position as follows:

	September 30, 2008	December 31, 2007
	(in millions)	
Other current assets	$ 2.6	$ 6.5
Other assets, net	9.6	6.4
Accounts payable and other	(118.3)	(165.5)
Other long-term liabilities	(134.3)	(192.9)
	$ (240.4)	$ (345.5)

The decrease in our obligation associated with derivative activities is primarily due to a decline in forward and daily natural gas, NGL and condensate prices from December 31, 2007 to September 30, 2008. Our portfolio of derivative financial instruments is largely comprised of long-term fixed price natural gas and NGL sales and purchase agreements.

We present the fair value of our derivative contracts on a net-by-counterparty basis in our consolidated statements of financial position when we believe a legal right of setoff exists under an enforceable netting agreement. Our credit exposure for OTC derivatives is directly with our counterparty

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and continues until the maturity or termination of the contract. When appropriate, valuations are adjusted for various factors such as credit and liquidity considerations.

The table below summarizes our derivative balances by counterparty credit quality (negative amounts represent our net obligations to pay the counterparty).

	September 30, 2008	December 31, 2007
	(in millions)	
Counterparty Credit Quality*		
AAA	$ —	$ —
AA	(164.0)	(298.3)
A	(76.4)	(47.2)
Lower than A	—	—
Total	$ (240.4)	$ (345.5)

* As determined by nationally recognized statistical ratings organizations.

12. SEGMENT INFORMATION

Our business is divided into operating segments, defined as components of the enterprise, about which financial information is available and evaluated regularly by our Chief Operating Decision Maker in deciding how resources are allocated and performance is assessed.

Each of our reportable segments is a business unit that offers different services and products that is managed separately, since each business segment requires different operating strategies. We have segregated our business activities into three distinct operating segments:

- Liquids;
- Natural Gas; and
- Marketing.

The following tables present financial information about our business segments:

	For the three months ended September 30, 2008				
	Liquids	Natural Gas	Marketing	Corporate(1)	Total
			(in millions)		
Total revenue	$ 209.3	$ 2,233.4	$ 1,352.8	$ —	$3,795.5
Less: Intersegment revenue	0.1	928.5	54.2	—	982.8
Operating revenue	209.2	1,304.9	1,298.6	—	2,812.7
Cost of natural gas	—	1,122.4	1,285.1	—	2,407.5
Operating and administrative	52.0	83.8	2.5	1.6	139.9
Power	35.0	—	—	—	35.0
Depreciation and amortization	26.7	31.5	0.4	—	58.6
Operating income	95.5	67.2	10.6	(1.6)	171.7
Interest expense	—	—	—	50.7	50.7
Other income	—	—	—	0.3	0.3
Income before income tax expense	95.5	67.2	10.6	(52.0)	121.3
Income tax expense	—	—	—	1.9	1.9
Net income	$ 95.5	$ 67.2	$ 10.6	$ (53.9)	$ 119.4
Capital expenditures (excluding acquisitions)	$ 261.1	$ 62.7	$ —	$ 4.3	$ 328.1

(1) Corporate consists of interest expense, interest income and certain other costs such as franchise and income taxes, which are not allocated to our business segments.

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	For the three months ended September 30, 2007				
	Liquids	Natural Gas	Marketing (in millions)	Corporate(1)	Total
Total revenue	$ 138.1	$ 1,376.0	$ 790.3	$ —	$2,304.4
Less: Intersegment revenue	—	528.7	64.8	—	593.5
Operating revenue	138.1	847.3	725.5	—	1,710.9
Cost of natural gas	—	711.2	719.6	—	1,430.8
Operating and administrative	33.9	68.1	2.3	(0.5)	103.8
Power	29.7	—	—	—	29.7
Depreciation and amortization	16.9	27.7	0.4	—	45.0
Operating income	57.6	40.3	3.2	0.5	101.6
Interest expense	—	—	—	23.4	23.4
Other income	—	—	—	0.4	0.4
Income before income tax expense	57.6	40.3	3.2	(22.5)	78.6
Income tax expense	—	—	—	1.3	1.3
Net income	$ 57.6	$ 40.3	$ 3.2	$ (23.8)	$ 77.3
Capital expenditures (excluding acquisitions)	$ 354.4	$ 186.8	$ 0.1	$ (4.4)	$ 536.9

(1) Corporate consists of interest expense, interest income and certain other costs such as franchise and income taxes, which are not allocated to our business segments.

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	As of and for the nine months ended September 30, 2008				
	Liquids	Natural Gas	Marketing (in millions)	Corporate[(1)]	Total
Total revenue	$ 555.5	$ 6,388.2	$ 4,025.8	$ —	$10,969.5
Less: Intersegment revenue	0.3	2,582.9	206.1	—	2,789.3
Operating revenue	555.2	3,805.3	3,819.7	—	8,180.2
Cost of natural gas	—	3,302.8	3,817.8	—	7,120.6
Operating and administrative	130.8	235.8	7.1	4.7	378.4
Power	104.6	—	—	—	104.6
Depreciation and amortization	73.0	88.8	1.3	—	163.1
Operating income	246.8	177.9	(6.5)	(4.7)	413.5
Interest expense	—	—	—	129.7	129.7
Other income	—	—	—	2.5	2.5
Income before income tax expense	246.8	177.9	(6.5)	(131.9)	286.3
Income tax expense	—	—	—	5.0	5.0
Net income	$ 246.8	$ 177.9	$ (6.5)	$ (136.9)	$ 281.3
Total assets	$3,709.9	$ 3,692.5	$ 353.1	$ 225.6	$ 7,981.1
Capital expenditures (excluding acquisitions)	$ 762.8	$ 226.6	$ —	$ 10.8	$ 1,000.2

(1) Corporate consists of interest expense, interest income and certain other costs such as franchise and income taxes, which are not allocated to our business segments.

	As of and for the nine months ended September 30, 2007				
	Liquids	Natural Gas	Marketing (in millions)	Corporate[(1)]	Total
Total revenue	$ 400.3	$ 4,084.7	$ 2,634.0	$ —	$7,119.0
Less: Intersegment revenue	—	1,767.6	189.1	—	1,956.7
Operating revenue	400.3	2,317.1	2,444.9	—	5,162.3
Cost of natural gas	—	1,966.2	2,424.5	—	4,390.7
Operating and administrative	108.2	190.3	5.8	2.3	306.6
Power	87.1	—	—	—	87.1
Depreciation and amortization	50.0	70.1	1.2	—	121.3
Operating income	155.0	90.5	13.4	(2.3)	256.6
Interest expense	—	—	—	70.2	70.2
Other income	—	—	—	2.3	2.3
Income before income tax expense	155.0	90.5	13.4	(70.2)	188.7
Income tax expense	—	—	—	3.7	3.7
Net income	$ 155.0	$ 90.5	$ 13.4	$ (73.9)	$ 185.0
Total assets	$2,624.1	$ 3,261.0	$ 261.6	$ 207.1	$6,353.8
Capital expenditures (excluding acquisitions)	$ 847.8	$ 572.7	$ 1.6	$ 6.3	$1,428.4

(1) Corporate consists of interest expense, interest income and certain other costs such as franchise and income taxes, which are not allocated to our business segments.

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13. SUBSEQUENT EVENT

Distribution to Partners

On October 13, 2008, the Board of Directors of Enbridge Management declared a distribution payable to our partners on November 14, 2008. The distribution will be paid to unitholders of record as of November 6, 2008, of our available cash of $108.8 million at September 30, 2008, or $0.990 per common unit. Of this distribution, $74.9 million will be paid in cash, $14.3 million will be distributed in i-units to our i-unitholder, $18.9 million will be distributed in Class C units to the holders of our Class C units and $0.7 million will be retained from the General Partner in respect of the i-unit and Class C unit distributions.

14. RECENT ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

Disclosures about Derivative Instruments and Hedging Activities

In March 2008, the Financial Accounting Standard Board, or FASB, issued Statement No. 161, *Disclosures about Derivative Instruments and Hedging Activities*, which is effective for fiscal years and interim periods beginning after November 15, 2008. The statement requires qualitative disclosures about a company's strategies and objectives for using derivatives, quantitative disclosures about fair value gains and losses on derivatives, and disclosures of credit-risk-related contingent features in derivative instruments. We do not anticipate adopting the provisions of this pronouncement early. We do not expect our adoption of this pronouncement to have a material affect on our financial statements other than modifications to our existing derivative disclosures to conform to the requirements set forth in the statement.

Calculation of Earnings Per Unit

In March 2008, the Emerging Issues Task Force, or EITF reached consensus on EITF Issue No. 07-4, *Application of the Two-Class Method under FASB Statement No. 128 to Master Limited Partnerships*. The pronouncement prescribes the manner in which a master limited partnership, or MLP, should allocate and present earnings per unit using the two-class method set forth in FASB Statement No. 128, *Earning per Share*. Under the two-class method, current period earnings are allocated to the general partner (including any embedded incentive distribution rights) and limited partners according to the distribution formula for available cash set forth in the partnership agreement. To the extent the partnership agreement does not explicitly limit distributions to the general partner; any earnings in excess of distributions are to be allocated to the general partner and limited partners utilizing the distribution formula for available cash specified in the partnership agreement. When current period distributions are in excess of earnings, the excess distributions are to be allocated to the general partner and limited partners based on their respective sharing of losses specified in the partnership agreement for the period. EITF 07-4 is to be applied retrospectively for all financial statements presented and is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. Earlier application is not permitted. We expect to adopt EITF 07-4 for our quarter ending March 31, 2009. We are currently evaluating the effect this pronouncement will have on our present computation of earnings per unit.

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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis of our financial condition and results of operations should be read together with our consolidated financial statements and the accompanying notes included in "Item 1. Financial Statements" of this report.

Additionally, this quarterly report on Form 10-Q should be read in conjunction with our Annual Report on Form 10-K for the year ended December 31, 2007.

DISRUPTION TO FUNCTIONING OF CAPITAL MARKETS

Multiple events during 2008 involving numerous financial institutions have effectively restricted current liquidity within the capital markets throughout the United States and around the world. Despite efforts by treasury and banking regulators in the United States, Europe and other nations around the world to provide liquidity to the financial sector, capital markets currently remain constrained. We expect that our ability to raise debt and equity at prices that are similar to offerings in recent years to be limited over the next three to six months and possibly longer should capital markets remain constrained.

In the weeks following the third quarter, our unit price declined to a closing low of $27.07 on October 10, 2008. Since that date our unit price recovered partially to a level of $37.89 on October 30, 2008. We intend to move forward with our planned internal growth projects, although our capital spending, particularly on the natural gas side of our business, will be reduced to moderate our capital raising requirements. In the near-term we will focus on maintaining sufficient liquidity to fund our growth programs, see "Liquidity and Capital Resources." Maintaining adequate liquidity may involve the issuance of debt and equity at less attractive terms than our most recent offerings and could involve the sale of non-core assets.

RESULTS OF OPERATIONS—OVERVIEW

We provide services to our customers and returns for our unitholders primarily through the following activities:

- Interstate pipeline transportation and storage of crude oil and liquid petroleum;
- Gathering, treating, processing and transportation of natural gas and natural gas liquids, or NGLs, through pipelines and related facilities; and
- Supply, transportation and sales services, including purchasing and selling natural gas and NGLs.

We conduct our business through three business segments: Liquids, Natural Gas and Marketing. These segments are strategic business units established by senior management to facilitate the achievement of our long-term objectives, to aid in resource allocation decisions and to assess operational performance.

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The following table reflects our operating income by business segment and corporate charges for the three and nine month periods ended September 30, 2008 and 2007:

	Three months ended September 30,		Nine months ended September 30,	
	2008	2007	2008	2007
	(unaudited; in millions)			
Operating Income				
Liquids	$ 95.5	$ 57.6	$ 246.8	$ 155.0
Natural Gas	67.2	40.3	177.9	90.5
Marketing	10.6	3.2	(6.5)	13.4
Corporate, operating and administrative	(1.6)	0.5	(4.7)	(2.3)
Total Operating Income	171.7	101.6	413.5	256.6
Interest expense	50.7	23.4	129.7	70.2
Other income	0.3	0.4	2.5	2.3
Income tax expense	1.9	1.3	5.0	3.7
Net Income	$ 119.4	$ 77.3	$ 281.3	$ 185.0

Several types of arrangements in our Natural Gas and Marketing segments expose us to market risk associated with changes in commodity prices where we receive natural gas or NGLs in return for the services we provide, or where we purchase natural gas or NGLs. We employ derivative financial instruments to reduce our exposure to natural gas and NGL price volatility. Some of these derivative financial instruments do not qualify for hedge accounting under the provisions of Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities* (SFAS No. 133), which can create volatility in our earnings that can be significant. However, these fluctuations in earnings do not affect our cash flow. Cash flow is only affected when we settle the derivative instrument. Based on our risk management policies, all of our derivative instruments are employed in connection with an underlying asset, liability and/or forecasted transaction and are not entered into with the objective of speculating on commodity prices.

Summary Analysis of Operating Results

Liquids

Operating income from our Liquids segment increased by $37.9 million to $95.5 million for the three months ended September 30, 2008, from the $57.6 million for the same period of 2007. Operating income for the nine months ended September 30, 2008 increased by $91.8 million to $246.8 million from $155.0 million for the same period of 2007. The increase in operating income of our Liquids segment is primarily due to the following:

- Tariff increases that went into effect in January, April, and July 2008, which include increases associated with the first stage of our Southern Access Expansion and the Phase V expansion of our North Dakota system;
- Additional revenue resulting from higher average crude oil prices associated with the allowance oil we receive in connection with our transportation services; and
- Higher delivery volumes on our Lakehead system.

Natural Gas

Operating income from our Natural Gas segment increased by $26.9 million to $67.2 million for the three months ended September 30, 2008 from the $40.3 million for the same period of 2007. Operating income for the nine months ended September 30, 2008 increased by $87.4 million to $177.9 million, from

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$90.5 million for the comparable period in 2007. The following factors affected the operating income of our Natural Gas business:

- $36.6 million of unrealized, non-cash mark-to-market gains from derivative instruments that do not qualify for hedge accounting treatment under SFAS No. 133, as compared with losses of $7.7 million for the same period of 2007;

- Improved margins resulting from higher prices we received for the natural gas, NGLs and condensate we receive as payment for the services we provide;

- Volume growth associated with the substantial completion of our East Texas natural gas system expansion and extension, referred to as the Clarity Project, coupled with strong production from the Bossier Trend, Granite Wash and Barnett Shale formations;

- Reduced revenues of approximately $8 to $9 million associated with the impact of hurricanes Gustav and Ike. Natural gas revenues decreased when third-party facilities downstream of our operations were damaged or without power. Physical damage was minimal, although we expect to incur capital and operating costs approximating $2 million to $3 million for repairs to several of our natural gas systems during the fourth quarter of 2008. All of our major natural gas systems were returned to pre-hurricane levels by the end of September;

- Lower processing margins resulting from higher average prices for natural gas used for processing, coupled with a continued shift in our contract mix from keep-whole to percentage of liquids, or POL, type contracts;

- Declines in the prices of natural gas and NGLs from June 30, 2008 to September 30, 2008 decreased the value of our in-kind natural gas imbalance receivables and produced non-cash charges to reduce the cost basis of our natural gas inventory to fair market value; and

- Variable operating and administrative cost increases associated with our system growth.

For the nine months ended September 30, 2008, in addition to the factors discussed above, we had $41.4 million of unrealized, non-cash mark-to-market gains, representing a $54.8 million improvement from the $13.4 million of losses we experienced in the same period of 2007. Additionally, operating income for the nine months ended September 30, 2008 was not affected by unscheduled maintenance at our Zybach processing facility and measurement losses which negatively affected operating income during the same period of 2007.

Marketing

Operating income from our Marketing segment increased by $7.4 million to $10.6 million for the three months ended September 30, 2008 compared to $3.2 million in the same period in 2007. For the nine months ended September 30, 2008, operating income decreased by $19.9 million to an operating loss of $6.5 million from operating income of $13.4 million in the same period of 2007. The operating results of our Marketing segment for the three months ended September 30, 2008 were positively affected by $11.0 million of unrealized, non-cash, mark-to-market gains associated with derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133 as compared with $2.9 million for the same period in 2007. Offsetting the unrealized non-cash, mark-to-market gains were $6.1 million and $3.0 million of non-cash charges for the three months ended September 30, 2008 and 2007, respectively, we recorded to reduce the cost basis of our natural gas inventory to fair market value. Both the non-cash, mark-to-market gains and revaluation charges resulted from declines in the price of natural gas during the three months ended September 30, 2008.

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Derivative Transactions and Hedging Activities

We record all derivative instruments in our consolidated financial statements at fair market value pursuant to the requirements of SFAS No. 133, and the guidance set forth in Statement of Financial Accounting Standards No. 157, *Fair Value Measurement* ("SFAS No. 157"). For those derivative instruments that do not qualify for hedge accounting, we record all changes in fair market value through our consolidated statements of income each period. Based on our risk management policies, all of our derivative instruments are employed in connection with an underlying asset, liability and/or forecasted transaction and are not entered into with the objective of speculating on interest rates or commodity prices.

The fair values of all our derivative instruments reflect our best estimate of the price we would receive for selling an asset or pay to transfer a liability in an orderly transaction with market participants at the measurement date. SFAS No. 157 defines how we are to determine fair value, establishes criteria for measuring fair value, and requires additional disclosures for assets and liabilities that we report at fair value. We adopted the provisions of SFAS No. 157 prospectively beginning January 1, 2008, which did not affect our results of operations, financial condition or cash flows due to the nature of our derivative instruments and our existing valuation methods.

Our unrealized, non-cash mark-to-market gains of $47.6 million and $17.5 million for the three and nine months ended September 30, 2008, are primarily the result of lower forward and daily prices of natural gas and NGLs relative to June 30, 2008 and December 31, 2007, respectively. The changes in fair value of our portfolio of commodity-based derivative instruments that do not qualify for hedge accounting are a result of the continuing volatility in the underlying prices for natural gas, NGLs and crude oil. During the three and nine months ended September 30, 2007, rising natural gas and NGL prices relative to the prices at June 30, 2007 and December 31, 2006, produced unrealized mark-to-market losses for the respective periods. Mark-to-market gains or losses create volatility in our operating results although the derivative instruments we have in place do not affect our cash flow until they are settled. We expect these non-cash gains and losses to reverse in future periods as we settle the derivative instruments against the underlying physical transactions. We intend to continue using derivative instruments to hedge our portfolio of natural gas and NGLs because of the economic benefit we derive from minimizing the volatility in our cash flows. Our continued use of derivative instruments is likely to result in additional unrealized, non-cash gains and losses in the future.

The following table presents the unrealized gains and losses associated with changes in the fair value of our derivative instruments, which are recorded as an element of "Cost of natural gas" in our consolidated statements of income and disclosed as a reconciling item on our consolidated statements of cash flows:

Derivative fair value gains (losses)	Three months ended September 30, 2008	Three months ended September 30, 2007	Nine months ended September 30, 2008	Nine months ended September 30, 2007
		(in millions)		
Natural Gas segment				
Hedge ineffectiveness	$ 0.1	$ (0.5)	$ (1.1)	$ (0.2)
Non-qualified hedges	36.5	(7.2)	42.5	(13.2)
Marketing segment				
Non-qualified hedges	11.0	2.9	(23.9)	(4.0)
Derivative fair value gains (losses)	$ 47.6	$ (4.8)	$ 17.5	$ (17.4)

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RESULTS OF OPERATIONS—BY SEGMENT

Liquids

The following tables set forth the operating results and statistics of our Liquids segment assets for the periods presented:

	Three months ended September 30,		Nine months ended September 30,	
	2008	2007	2008	2007
	(unaudited; in millions)			
Operating Results				
Operating revenues	$ 209.2	$ 138.1	$ 555.2	$ 400.3
Operating and administrative	52.0	33.9	130.8	108.2
Power	35.0	29.7	104.6	87.1
Depreciation and amortization	26.7	16.9	73.0	50.0
Operating expenses	113.7	80.5	308.4	245.3
Operating Income	$ 95.5	$ 57.6	$ 246.8	$ 155.0
Operating Statistics				
Lakehead system:				
United States(1)	1,233	1,187	1,242	1,191
Province of Ontario(1)	331	325	344	333
Total Lakehead system deliveries(1)	1,564	1,512	1,586	1,524
Barrel miles (billions)	105	101	317	301
Average haul (miles)	730	723	729	723
Mid-Continent system deliveries(1)	227	255	238	248
North Dakota system:				
Trunkline	101	93	103	91
Gathering	6	7	6	6
Total North Dakota system deliveries(1)	107	100	109	97
Total Liquids Segment Delivery Volumes(1)	1,898	1,867	1,933	1,869

(1) Average barrels per day ("Bpd") in thousands.

Three months ended September 30, 2008 compared with three months ended September 30, 2007

Our Liquids segment accounted for $95.5 million of operating income during the three months ended September 30, 2008, an increase of $37.9 million from the $57.6 million generated during the same period in 2007. The favorable results are attributable to increased volumes transported on our Liquids systems coupled with tariff increases that went into effect during 2008, partially offset by higher power, operating and administrative costs, and depreciation. The majority of the increase in delivery volumes is attributable to our Lakehead system; however, our North Dakota system also realized increased delivery volumes.

Operating revenue for the three months ended September 30, 2008 increased by $71.1 million to $209.2 million from $138.1 million for the same period in 2007. The increase in operating revenue is due to the following:

- Increased average tariffs on all of our major systems;

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- The toll charges discussed below that are associated with the first stage of our Southern Access expansion project became effective April 1, 2008. We realize revenues in connection with this increased surcharge as crude oil is delivered from our Lakehead system. Our Southern Access expansion project includes a 42-inch diameter pipeline from Superior to Delavan, Wisconsin along with pump station enhancements upstream and downstream of this segment. Completion of the first stage of this project added approximately 190,000 Bpd of capacity and was considered available for service April 1, 2008;

- Higher delivery volumes on our Lakehead system; and

- Additional revenue resulting from higher crude oil prices associated with the allowance oil we receive in connection with our transportation services.

The increases in average tariffs on all three Liquids systems coupled with longer hauls and transportation of more heavy crude oil contributed approximately $57.0 million of additional operating revenue. We implemented new tariffs in 2008 on our Lakehead system effective April 1, 2008 to reflect true-ups for the difference between estimated and actual cost and throughput data for the prior year and our projected costs and throughput for 2008. The projected costs for 2008 include four projects: (1) the Southern Access mainline expansion, (2) two Superior terminal tank projects, (3) two Griffith terminal tank projects and (4) the Clearbrook Manifold project. We also implemented new tariffs on our North Dakota system effective January 1, 2008 that are applicable for five years and are applied to all transportation routes with a destination of Clearbrook, Minnesota. Additionally, we increased the average tariffs on all three of our Liquids systems in connection with the annual index rate ceiling adjustment that went into effect July 1, 2008. Additional discussion of these tariffs is provided below under the section labeled *Regulatory Matters—FERC Transportation Tariffs–Liquids.*

Average delivery volumes on our Lakehead system increased approximately 3.4 percent, to 1.564 million Bpd during the three months ended September 30, 2008 from 1.512 million Bpd during the same period in 2007, contributing an additional $3.6 million to operating revenue. The increase in average deliveries on our Lakehead system is primarily derived from increases of crude oil supplies from upstream production facilities associated with the ongoing development of the Alberta Oil Sands. However, crude oil supplies from western Canada were lower than we expected due to two primary factors. First, Suncor, an oil sands producer in Alberta, Canada, had limited hydrotreating capacity in August and September of 2008 as well as an accident on their oil sands pipeline both of which reduced production volumes. Second, Syncrude, another oil sands producer, is currently undergoing a maintenance turnaround that has resulted in lower production volumes.

Included in our transportation tariff is an allowance from our customers for the transportation of their crude oil. We recognize revenue for this allowance at the prevailing market price for crude oil. The average prices of crude oil during the three months ended September 30, 2008 are substantially higher than the average prices for the same period of 2007. For example, the average price of West Texas Intermediate crude oil has increased approximately 60 percent for the three months ended September 30, 2008 as compared with the same period in 2007. As a result of the increase in crude oil prices, we experienced an approximate $8.2 million increase in allowance oil revenues.

Operating and administrative expenses for the Liquids segment increased $18.1 million for the three months ended September 30, 2008, compared with the same period in 2007. The increase in these costs is primarily attributable to the following:

- Increased workforce related costs associated with the operational, administrative, regulatory, and compliance support necessary for our growing systems;

- Unfavorable oil measurement adjustments as described below;

- Higher costs incurred in connection with our pipeline integrity management program;

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- Further costs incurred in connection with the crude oil release and fire on Line 3 of our Lakehead system; and

- Favorable settlements of property tax assessments that were realized during the three months ended September 30, 2007 which were not present for the same period in 2008.

Oil measurement adjustments occur as part of the normal operations associated with our Liquids systems. The three types of oil measurement adjustments that normally occur on our systems include:

- Physical gains and losses, which result from evaporation, shrinkage, differences in measurement between receipt and delivery locations and other operational incidents;

- Degradation, which results from mixing at the interface between higher quality light crude oil and lower quality heavy crude oil; and

- Revaluation, which is a function of crude oil prices, of the level of our carriers inventory and the inventory positions of customers.

Power costs increased $5.3 million in the three months ended September 30, 2008, compared with the same period in 2007, predominantly due to the higher delivery volumes coupled with higher utility rates we are charged by our power suppliers. We have experienced a trend of increasing electricity rates from our power suppliers due to higher natural gas and coal costs.

The increase in depreciation expense of $9.8 million is attributable to the additional assets we have placed in service during the last quarter of 2007 and the first three quarters of 2008, including the Southern Access Expansion stage one assets that we placed in service during the second quarter of 2008 along with the assets placed into service on our North Dakota and Mid-Continent systems.

Nine months ended September 30, 2008 compared with nine months ended September 30, 2007

Our Liquids segment accounted for $246.8 million of operating income during the nine months ended September 30, 2008, representing a $91.8 million increase over the $155.0 million for the same period in 2007. The components comprising our operating income changed during the nine months ended September 30, 2008 compared with the nine months ended September 30, 2007, primarily for the same reasons as noted above in our three-month analysis except that we had more favorable experience with oil measurement adjustments for the nine months ended September 30, 2008.

Future Prospects Update for Liquids

We and Enbridge Inc. ("Enbridge") are actively working with our customers to develop transportation options that will allow Canadian crude oil greater access to markets throughout the United States ("U.S."). The following discussion provides an update to the status of projects we and Enbridge are developing and should be read in conjunction with the information included in Item 7 of our Annual Report on Form 10-K for the year ended December 31, 2007.

Partnership Projects

Southern Access

We continue to progress on the second and final stage of the expansion project which will provide additional upstream pumping capacity and a new pipeline from Delavan to Flanagan, Illinois. Construction of this stage of the project commenced on June 1, 2008. We expect to complete this phase of the expansion by the end of the first quarter of 2009. Completion of the total Southern Access expansion project will create a 454-mile pipeline with approximately 400,000 Bpd of incremental capacity on our Lakehead system.

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Alberta Clipper

The Alberta Clipper project involves construction of a new 36-inch diameter, 1,000 mile heavy crude oil pipeline from Hardisty, Alberta to Superior, generally within or adjacent to our and Enbridge's existing rights-of-way. We will construct approximately 330 miles of the new pipeline from the International Border near Neche, North Dakota to Superior, a delivery connection at Clearbrook, Minnesota and an additional tank at Superior. Alberta Clipper will have an initial capacity of 450,000 Bpd and allows for expansions up to 800,000 Bpd by adding pump stations. In addition, complementary capacity on the Southern Access 42-inch pipeline from Superior to Flanagan will be obtained by installing additional pump stations. We anticipate that our share of the construction cost for the United States segment of the project will approximate $1.2 billion. Alberta Clipper will be a common carrier line fully integrated with the Enbridge/Lakehead mainline systems for tolling purposes. We and Enbridge are progressing with the project, which is expected to be in service in mid-2010. We expect to begin construction on the U.S. leg of the project in the first quarter of 2009.

North Dakota

The United States Geological Survey, or USGS, completed an assessment of the undiscovered oil and associated natural gas resources of the Upper Devonian—Lower Mississippi Bakken formation in the United States portion of the Williston Basin and has determined there to be 3.0 to 4.3 billion barrels of technologically recoverable oil. Regional producers in the Williston basin areas of Montana and North Dakota have expressed interest in further expansion of pipeline capacity on our North Dakota system. As a result, we have commenced an approximate $0.15 billion additional expansion consisting of upgrades to existing pump stations, additional tankage, as well as extensive use of drag reducing agents ("DRA") that are injected into the pipeline. This expansion of our North Dakota system, referred to as Phase VI, is expected to increase system capacity to 161,000 Bpd from the 110,000 Bpd that is currently available. The commercial structure for this expansion is a cost-of-service based surcharge that will be added to the existing tariff rates. The proposed tolling methodology is similar to the structure being used on the recently completed Phase V expansion project and was approved by the Federal Energy Regulation Commission ("FERC") in October 2008.

Superior and Griffith Storage

Due to forecasted production increases of synthetic heavy crude oil that we anticipate will be transported on the Enbridge/Lakehead mainline systems from Western Canada to Chicago, Illinois; we are constructing additional crude oil storage tanks at Superior and Griffith to accommodate the anticipated volumes. We are building two tanks with operational capacity of approximately 205,000 barrels each. The Superior tank was completed in early September 2008 and the Griffith tank is on schedule to be completed in December 2008.

Trailbreaker (formerly Eastern PADD II Access)

We and Enbridge are jointly developing plans to provide access for western Canadian crude oil to refineries along the United States Eastern Seaboard and the United States Gulf Coast ("U.S. Gulf Coast") via the marine terminal at Portland, Maine. The Trailbreaker project involves the expansion and reversal of existing facilities to create a pipeline route to Portland that is ready for use in 2010. Commercial terms for the project are being negotiated which will be subject to regulatory approvals in both the United States and Canada. Preliminary estimates indicate our portion of the project will approximate $0.3 billion (excluding capitalized interest).

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Enbridge and Other Projects

Spearhead Pipeline

In another effort to provide shippers access to new markets, Enbridge acquired a pipeline that previously shipped crude oil from Cushing, Oklahoma to Chicago. Enbridge reversed the pipeline, renamed it Spearhead, and began delivering Canadian crude oil to the major oil hub at Cushing in March 2006. Since then, the pipeline has operated at or near its capacity of 125,000 Bpd. In the first half of 2007, Enbridge successfully concluded a binding open season for expansion of the pipeline to 190,000 Bpd, with binding commitments for capacity of 30,000 Bpd. In December 2007, the FERC issued a favorable declaratory order effectively approving the tolling methodology and priority service for shippers with binding commitments. Construction has commenced on the 65,000 Bpd expansion, which is expected to be in service in early 2009. The Spearhead pipeline is complementary to our Lakehead system as Western Canadian crude oil is carried on our Lakehead system as far as Chicago, and then transferred to the Spearhead pipeline.

Southern Access Extension

In July 2006, Enbridge announced that it received support from shippers and the Canadian Association of Petroleum Producers ("CAPP") for its 36-inch diameter Southern Access Extension pipeline from Flanagan to Patoka, Illinois. The extension will broaden the reach of the Enbridge/Lakehead mainline system to incremental markets accessible from the Patoka hub. This project is being undertaken by Enbridge, however, we will benefit from the incremental volumes moving through our Lakehead system to reach this extension. Enbridge filed a petition for declaratory order with the FERC in October 2007, which was denied on May 7, 2008. Enbridge is currently working with shippers to develop a new commercial structure for the pipeline.

Southern Lights

Following completion of a successful open season in 2006, Enbridge initiated its Southern Lights project to construct a diluent pipeline from Chicago to Edmonton, Alberta, Canada to meet the growing demand for crude oil diluent required to transport the heavy oil and bitumen (a thick, tar-like form of oil) being produced in increasing volumes from the Alberta oil sands. The project involves the exchange of a 156-mile section of pipeline we own, referred to as Line 13, for a similar section of a new pipeline to be constructed as part of the project. In addition, this project involves a reconfiguration of our light crude mainline system which will provide an additional 45,000 Bpd of effective capacity at no cost to us. We expect to benefit from increased heavy crude oil shipments, which will be facilitated by the diluent line.

In February 2008, the National Energy Board ("NEB") issued its approval and in May 2008 the Canadian Government also issued its Governor In Council ("GIC") approval for the Canadian portion of the Southern Lights project. The GIC approval has been challenged through proceedings in the Federal Court of Canada by certain First Nations on the basis that the Canadian government failed to adequately consult with affected First Nations. No hearing date has been set and the likelihood of success of this action is not determinable at this time. Enbridge has filed the majority of necessary applications for the United States portion of the project with United States federal and state regulatory agencies. Enbridge filed a petition for declaratory order with the FERC setting forth the rate structure for establishing tolls and the proposed swap of Line 13 discussed above, which the FERC approved in late December 2007. In conjunction with our Southern Access project, the Southern Lights project has been allowed the right to exercise eminent domain for right-of-way in Illinois. Construction and right-of-way acquisition related to this project continues in tandem with the Southern Access project. This project is expected to be placed in service in 2010.

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United States Gulf Coast Joint Initiative

In August 2008, Enbridge and BP Pipelines (North America) Inc. ("BP") announced they are currently developing an initiative to deliver incremental volumes of Canadian crude oil to the U.S. Gulf Coast. The initiative, as envisioned, involves the reversal of the BP #1 pipeline system between Flanagan and Cushing, as well as the construction of a new pipeline between Cushing and Houston, Texas. The scope of the project provides for a pipeline system with over 150,000 Bpd of new capacity between Flanagan and Cushing and approximately 250,000 Bpd of capacity between Cushing and Houston. Enbridge is currently working with BP to develop commercial terms to present to a targeted list of potential shippers to solicit binding support prior to launching an open season later this year. The target in-service date for this pipeline system is late 2012.

Texas Access Pipeline

The initiative discussed above aligns with the Enbridge strategy to pursue a staged approach to the U.S. Gulf Coast that matches supply growth. The Texas Access pipeline will be brought to the forefront when a large volume solution to the U.S. Gulf Coast is required.

Natural Gas

The following tables set forth the operating results of our Natural Gas segment assets and approximate average daily volumes of our major systems in millions of British Thermal Units per day ("MMBtu/d") for the periods presented:

	Three months ended September 30,		Nine months ended September 30,	
	2008	2007	2008	2007
	(unaudited; in millions)			
Operating Results				
Operating revenues	$ 1,304.9	$ 847.3	$ 3,805.3	$ 2,317.1
Cost of natural gas	1,122.4	711.2	3,302.8	1,966.2
Operating and administrative	83.8	68.1	235.8	190.3
Depreciation and amortization	31.5	27.7	88.8	70.1
Operating expenses	1,237.7	807.0	3,627.4	2,226.6
Operating Income	$ 67.2	$ 40.3	$ 177.9	$ 90.5
Operating Statistics (MMBtu/d)				
East Texas	1,443,000	1,158,000	1,431,000	1,162,000
Anadarko	682,000	594,000	648,000	588,000
North Texas	388,000	360,000	383,000	344,000
UTOS	96,000	212,000	157,000	176,000
MidLa	96,000	110,000	104,000	117,000
AlaTenn	28,000	30,000	41,000	41,000
Bamagas	99,000	148,000	79,000	126,000
Other major intrastates	204,000	205,000	215,000	241,000
Total[(1)]	3,036,000	2,817,000	3,058,000	2,795,000

(1) We have excluded from the table above average daily volumes of 10,000 MMBtu/d and 24,000 MMBtu/d for the three and nine month periods ended September 30, 2007, respectively, associated with the KPC system which we sold in November 2007.

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Three months ended September 30, 2008 compared with three months ended September 30, 2007

Our Natural Gas segment contributed $67.2 million of operating income for the three months ended September 30, 2008, an increase of $26.9 million from the $40.3 million contributed in the corresponding period of 2007. The following discussion presents the primary factors affecting the operating income of our Natural Gas business for the three months ended September 30, 2008 as compared with the same period of 2007:

- $36.6 million of unrealized, non-cash mark-to-market gains from derivative instruments that do not qualify for hedge accounting treatment under SFAS No. 133, as compared with losses of $7.7 million for the same period of 2007;

- Reduced revenues of approximately $8 to $9 million associated with the impact of hurricanes Gustav and Ike. Natural gas revenues decreased when third-party facilities downstream of our operations were damaged or without power. Physical damage was minimal, although we expect to incur capital and operating costs approximating $2 million to $3 million for repairs to several of our natural gas systems during the fourth quarter of 2008. All of our major natural gas systems were returned to pre-hurricane levels by the end of September;

- In-kind payments we receive for the services we provide in the form of natural gas, NGLs and condensate have generated improved margins as a result of higher average prices in the commodities market;

- Volume growth associated with the substantial completion of our East Texas natural gas system expansion and extension, referred to as the Clarity Project, coupled with strong production from the Bossier Trend, Granite Wash and Barnett Shale formations;

- Declining processing margins due to higher costs of natural gas used for processing as the average price for natural gas declined less than the price for NGLs, along with continued changes in our contract mix of keep whole and POL type contracts;

- Declines in the prices of natural gas and NGLs from June 30, 2008 to September 30, 2008 decreased the value of our in-kind natural gas imbalance receivables and produced non-cash charges to reduce the cost basis of our natural gas inventory to fair market value; and

- Increased workforce, repair and maintenance, rents, leases, and depreciation associated with our system growth.

Revenue for our Natural Gas business is derived from the fees or commodities we receive from the gathering, transportation, processing and treating of natural gas and NGLs for our customers. We are exposed to fluctuations in commodity prices in the near term on 20 to 30 percent of the natural gas, NGLs and condensate we expect to receive as compensation for our services. As a result of this unhedged commodity price exposure, our margins increase when the prices of these commodities are rising and decrease when the prices are declining. For the three months ended September 30, 2008, we realized approximately $22 million of additional margin compared with the same period of 2007 primarily due to the higher prices we received from the sale of the unhedged natural gas, NGLs and condensate that we received in-kind as compensation for our services.

We enter into derivative financial instruments to hedge 70 to 80 percent of our near-term exposure to commodity prices associated with the in-kind compensation we receive for our services. As a result of entering into these derivative instruments, we have largely fixed the amount of cash that we will pay and receive in the future when we sell the processed natural gas, NGLs and condensate, even though the market price of these commodities will continue to fluctuate during that time. Many of these derivative financial instruments do not qualify for hedge accounting which results in the derivative instrument being marked-to-market in our operating results. This accounting treatment produces unrealized non-cash gains

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and losses in our reported operating results that can be significant during periods when the commodity price environment is volatile.

The operating income of our Natural Gas segment for the three months ended September 30, 2008 was positively affected by unrealized non-cash, mark-to-market net gains of $36.6 million, representing an increase of $44.3 million from the $7.7 million of losses we recorded for the same period of 2007. During the three months ended September 30, 2008, declines in the forward and daily market prices of natural produced non-cash, mark-to-market gains in our portfolio of derivative instruments. The declining price environment that was prevalent during the three months ended September 30, 2008, was not present during the same period of 2007. We expect the net mark-to-market gains to be offset when the related physical transactions are settled. The following table depicts the affect that unrealized non-cash mark-to-market gains and losses had on the operating results of our Natural Gas business for the three and nine months ended September 30, 2008 and 2007:

Derivative fair value gains (losses)	Three months ended September 30, 2008	Three months ended September 30, 2007	Nine months ended September 30, 2008	Nine months ended September 30, 2007
	(in millions)			
Natural Gas segment				
Hedge ineffectiveness	$ 0.1	$ (0.5)	$ (1.1)	$ (0.2)
Non-qualified hedges	36.5	(7.2)	42.5	(13.2)
Derivative fair value gains (losses)	$ 36.6	$ (7.7)	$ 41.4	$ (13.4)

The increase in the average daily volume of our Natural Gas business is directly attributable to the significant investments we have made to expand the capacity and service capability of our systems. We completed the following projects during 2008 and the last quarter of 2007, which have contributed to the increase in average daily volumes and operating results of our major natural gas systems:

- In May 2008 our expansion of the Aker treating plant on our East Texas system was completed and placed into service adding 125 million cubic feet per day, or MMcf/d, of treating capacity.
- The $635 million expansion and extension of our East Texas natural gas system, referred to as the Clarity project, is substantially complete and includes:
- A new 36-inch natural gas pipeline from Bethel, Texas to Southeast Texas near Beaumont, Texas; and
- The Marquez treating plant with capacity of approximately 200 MMcf/d and additional pipeline capacity to the existing southeast section of this area was completed and placed in service in March 2007.

  We expect to finish an additional pipeline connection and two compression stations during the first quarter of 2009. The total added capacity related to this project will then total approximately 700 MMcf/d.
- In the first quarter of 2008 we completed construction of a 25-mile, 20-inch diameter pipeline from a lateral on our East Texas system to gather additional production being developed in East Texas.
- In the latter half of 2007, we completed construction of three hydrocarbon dewpoint control facilities on our East Texas system to add processing capacity to meet the increasingly more stringent pipeline gas quality specifications. These facilities have a cumulative capacity of 550 MMcf/d and obtain a significant portion of their revenues from fees rather than keep-whole processing or percentage-of-liquids revenues.
- Construction and expansion of the Weatherford processing facility within our North Texas system was completed late in 2007 and added approximately 75 MMcf/d of processing capacity.

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With the expansions we completed in 2007 and 2008 we are now able to provide additional gathering, processing, treating and transportation services for our customers which has contributed to our volume growth in the third quarter of 2008. Volume and revenue growth is also the result of additional wellhead supply contracts and continued robust drilling activity in the areas served by our Natural Gas business, primarily the Bossier Trend, Barnett Shale and Granite Wash areas. We expect the volumes on our major natural gas systems to continue increasing throughout the year as a result of our investments to expand the capacity of our systems to provide gathering, processing and transportation services to meet the needs of producers in the areas we serve.

During the third quarter of 2008, we experienced operational disruptions to our onshore and offshore natural gas facilities as a result of hurricanes Gustav and Ike. Our facilities in Texas and Louisiana sustained minimal physical damage from the hurricanes, although some of our natural gas systems had lower throughput and revenues in the month of September due to the inability of third-party downstream facilities to receive deliveries of our natural gas and NGLs. These temporary disruptions curtailed our ability to gather unprocessed natural gas at our processing plants and transport natural gas to markets in the Texas and Louisiana regions. Our current estimate of lost revenue associated with the hurricanes is $8 million to $9 million coupled with capital and operating costs of $2 million to $3 million we expect to incur in the fourth quarter for repairs to our damaged facilities. We do not anticipate recovery of any significant amounts of insurance for these losses. The majority of our facilities returned to normal operation by the end of September.

The processing margins we derive from processing natural gas under keep-whole arrangements that exist within our East Texas, North Texas and Anadarko systems declined 52 percent during the third quarter of 2008 in relation to the same period of 2007. Operating income derived from keep-whole processing arrangements for the three months ended September 30, 2008 was $18.4 million, representing a decrease of $19.6 million from the $38.0 million we produced for the same period in 2007. During the third quarter of 2008, NGL and crude oil prices began to decline faster than natural gas prices, which have the effect of reducing revenue we derive from our processing assets less the cost of natural gas purchased for processing. In addition to the affect that changing prices have had on the processing margins we derive from processing natural gas under keep-whole arrangements, we continue to experience a trend of replacing or renegotiating some of our existing keep-whole contracts with percentage of liquids, or POL, type contracts and other similar arrangements. This trend may reduce our exposure to commodity price risk along with a portion of the operating income we derive from processing natural gas under keep-whole arrangements.

Despite the higher average daily prices for natural gas and NGLs we received during the three months ended September 30, 2008 relative to the same period of 2007, the daily prices for natural gas and NGLs at September 30, 2008 were lower than the prices for these commodities at June 30, 2008. The lower commodity prices at September 30, 2008 produced approximately $4.8 million of revaluation losses with respect to our in-kind natural gas imbalances, as well as approximately $2.2 million of non-cash charges to reduce the cost basis of our natural gas inventory to fair market value. We did not experience similar fluctuations in commodity prices for the three months ended September 30, 2007.

Operating and administrative costs of our Natural Gas segment were $15.7 million greater for the three months ended September 30, 2008 than the three months ended September 30, 2007, primarily as a result of increased workforce-related costs associated with the expansion of our systems, maintenance activities and other costs that are mostly variable with volumes. Our general partner charges us the costs associated with employees and related benefits for personnel that are assigned to us or otherwise provide us with managerial and administrative services. The portion of compensation and related costs we are charged is dependent upon such items as estimated time spent, miles of pipe and headcount. In addition we have experienced an increase in outside contract labor cost, given the high demand and competitive rates within our industry as a result of pipeline expansions across the areas we serve.

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Materials, supplies and other costs along with repair and maintenance costs were higher predominantly due to the increase in volumes and expansion of our natural gas systems. Repair and maintenance costs include compressor maintenance, downtime for routine and unscheduled maintenance, pipeline integrity costs and other similar items that have increased with the expansion of our natural gas systems. We expect workforce related costs in addition to materials, supplies and other costs to increase in relation to the increase in volumes of natural gas services we provide.

Depreciation expense for our Natural Gas segment was higher in the third quarter of 2008 as compared the third quarter of 2007, as a result of the capital projects completed and placed in-service during the first nine months of 2008 and the last quarter of 2007. We expect deprecation expense will be higher in 2008 as a result of the projects we completed and placed in service throughout 2007 and the first half of 2008.

Nine months ended September 30, 2008 compared with nine months ended September 30, 2007

Our Natural Gas segment accounted for $177.9 million of operating income during the nine months ended September 30, 2008, representing an $87.4 million increase over the $90.5 million for the same period in 2007. The components comprising our operating income changed favorably during the nine months ended September 30, 2008 compared with the nine months ended September 30, 2007, primarily for the same reasons noted above in our three-month analysis except for those items described below.

The operating income of our Natural Gas business derived from processing increased by approximately $30 million during the nine months ended September 30, 2008, as compared with the same period in 2007, despite the impact of the hurricanes and the declining price environment that occurred late in the third quarter of 2008 as discussed above under our three month analysis. For a majority of the nine months ended September 30, 2008, we have benefitted from a favorable pricing environment for the production of NGLs. NGL prices were high relative to natural gas prices during most of the nine month period of 2008 providing a favorable environment for the production of NGLs from our processing assets. We have also benefitted from the processing capacity we added on our Anadarko system in April 2007 of approximately 120 MMcf/d and the 75 MMcf/d we added on our North Texas system in the second half of 2007. The added processing capacity provided us with the ability to generate additional processing margin from the NGLs we produced during the first nine months of 2008. Our Zybach processing plant has also continued to operate at expected levels during the first nine months of 2008, which compares favorably with the same period of 2007 when we experienced operational issues that reduced processing margins by approximately $11 million.

Operating income for the nine months ended September 30, 2008 was positively affected by the unrealized non-cash, mark-to-market net gains of $41.4 million from our derivative activities, which is approximately $54.8 million more than the $13.4 million of losses we recorded for the same period of 2007. We expect the net mark-to-market gains and losses to be offset when the related physical transactions are settled.

Future Prospects Update for Natural Gas

Significant liquidity tightening and volatility in the capital markets will necessitate a less aggressive capital program in our natural gas business in the near term. During this period of volatility we will continue to focus our efforts primarily on development of our existing pipeline systems. We continue to evaluate strategic opportunities to further expand the service capabilities of our existing system and we may pursue opportunities to divest any non-strategic natural gas assets as conditions warrant.

Results of our natural gas gathering and processing business depend upon the drilling activities of natural gas producers in the areas we serve. During the third quarter of 2008, increased production from active drilling in the areas where our gathering systems are located has contributed to our volume growth. Recent announcements by natural gas producers forecasting reduced exploration and development

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programs could impact the rate of growth in our natural gas assets. However, we believe our assets are located in three areas where producers are likely to remain active due to the higher probability of success associated with resource developments in the East Texas, North Texas and Anadarko regions. We believe this factor should temper the impact of lower natural gas production drilling programs on the results of our Natural Gas business.

Milsap Plant

We plan to purchase and construct a 55 MMcf/d cryogenic processing plant and associated piping, which we refer to as the Millsap Plant Project, to accommodate Barnett Shale growth opportunities in North Texas. The design will incorporate flexibility to expand the inlet capacity of the plant to 75 MMcf/d (through expansion of inlet and residue compression) should volume growth exceed our expected forecast. We expect the cost to complete construction to approximate $100 million with an in service date late in the first quarter of 2010.

Shelby County Loop and Compression

We commenced construction during the third quarter of 2008 to add compression at the Carthage Hub and on the Shelby lateral sections of our East Texas system. We have also initiated construction to increase the capacity of the East Texas system in the area by installing approximately 26 miles of 20-inch pipeline. We expect to complete this project during 2009 at an approximate cost of $60 million.

Marketing

The following table sets forth the operating results of our Marketing segment assets for the periods presented:

	Three months ended September 30,		Nine months ended September 30,	
	2008	2007	2008	2007
	(unaudited; in millions)			
Operating Results				
Operating revenues	$ 1,298.6	$ 725.5	$3,819.7	$2,444.9
Cost of natural gas	1,285.1	719.6	3,817.8	2,424.5
Operating and administrative	2.5	2.3	7.1	5.8
Depreciation and amortization	0.4	0.4	1.3	1.2
Operating expenses	1,288.0	722.3	3,826.2	2,431.5
Operating Income (Loss)	$ 10.6	$ 3.2	$ (6.5)	$ 13.4

A majority of the operating income of our Marketing segment is derived from selling natural gas received from producers on our Natural Gas segment pipeline assets to customers who need natural gas. As a result of our natural gas system expansions and other initiatives, our Marketing business now has access to several additional downstream natural gas pipelines, which it can use to transport natural gas to primary markets where it can be sold at more favorable prices.

We adopted the provisions of SFAS No. 157 effective January 1, 2008, which did not affect the operating results of our Marketing business, but did expand the disclosures we provide about how we determine the fair value of our derivative instruments. Refer to the discussions included in Notes 9 and 10 of our consolidated financial statements included in Item 1 of this report and also to the discussions below under "Derivative Activities" and the "Quantitative and Qualitative Disclosures about Market Risk" we include in Item 3 of this report for more information about our derivative activities.

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Three months ended September 30, 2008 compared with three months ended September 30, 2007

The operating income of our Marketing segment increased to $10.6 million for the third quarter of 2008 from $3.2 million for the corresponding period in 2007. Included in operating income for the third quarter of 2008 are approximately $11.0 million of unrealized, non-cash, mark-to-market gains associated with derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133, as compared with the $2.9 million of unrealized mark-to-market gains for the same period of 2007. During the three months ended September 30, 2008, declines in the forward and daily market prices of natural gas produced non-cash, mark-to-market gains in our portfolio of derivative instruments in excess of those produced during the same period of 2007. We expect these net mark-to-market gains to be offset when the related physical transactions are settled.

Operating income for the three months ended September 30, 2008 was also negatively affected by non-cash charges of $6.1 million we recorded to reduce the cost basis of our natural gas inventory to fair market value at September 30, 2008, which is $3.1 million more than the $3.0 million non-cash charge we recorded for the same period of 2007. The average daily price of natural gas as published by Platt's Gas Daily for Henry Hub was approximately $7.23 per MMBtu for the month of September 2008, a decline from $12.60 per MMBtu for the month of June 2008. As a result of this decline in the price of natural gas inventory at our storage locations from June 30, 2008 to September 30, 2008, the weighted average cost of our natural gas inventory at September 30, 2008 exceeded the market price of natural gas by approximately $6.1 million. Due to our hedging structures, we expect that a majority of these charges will be offset by future financial transactions that will settle at the time the natural gas inventory is sold.

The operating and administrative expenses of our Marketing business were slightly more in the quarter ended September 30, 2008 as compared with the same period of 2007 due to additional workforce related costs associated with the employees and related benefits for personnel that are assigned to us or otherwise provide us with managerial and administrative services.

Nine months ended September 30, 2008 compared with nine months ended September 30, 2007

Operating income of our Marketing segment declined to a loss of $6.5 million for the nine month period ended September 30, 2008 from income of $13.4 million for the corresponding period in 2007. Included in the operating loss for the first nine months of 2008 are approximately $23.9 million of unrealized, non-cash, mark-to-market losses associated with derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133, compared to the $4.0 million of unrealized mark-to-market losses for the comparable period of 2007. The unrealized, mark-to-market losses for the nine months ended September 30, 2008 result from increases in the forward and daily market prices of natural gas from December 31, 2007. We expect these net mark-to-market losses to be offset when the related physical transactions are settled.

The operating and administrative expenses of our Marketing business are slightly more in the nine months ended September 30, 2008 as compared with the same period of 2007 due to additional workforce related costs associated with the employees and related benefits for personnel that are assigned to us or otherwise provide us with managerial and administrative services.

Corporate

Interest expense was $50.7 million and $129.7 million for the three and nine months ended September 30, 2008, compared with $23.4 million and $70.2 million for the corresponding periods in 2007. The increases are primarily the result of higher weighted average debt balance associated with the following debt issuances:

- $200 million of our Zero Coupon Senior Notes in August 2007,
- $400 million of our Junior Subordinated Notes in September 2007,

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- $400 million of our 6.5% Senior Notes in April 2008, and
- $400 million of our 7.5% Senior Notes in April 2008.

Our weighted average interest rate is 6.3% for the three months and 6.0% for the nine months ended September 30, 2008 as compared with our weighted average interest rates of 6.0% and 5.9% for the same periods in 2007.

Further contributing to the increase in interest expense is the $4.0 million decrease in interest capitalized to our construction projects in the three months ended September 30, 2008 from the same period in 2007. Conversely, the increase in interest expense in the first nine months of 2008 was offset by an additional $5.6 million of capitalized interest when compared to the same period in 2007. For the three and nine months ended September 30, 2008 and 2007, our interest cost is comprised of the following:

	Three months ended September 30,		Nine months ended September 30,	
	2008	2007	2008	2007
	(unaudited; in millions)			
Interest expense	$ 50.7	$ 23.4	$ 129.7	$ 70.2
Interest capitalized	6.2	10.2	31.2	25.6
Interest cost incurred	$ 56.9	$ 33.6	$ 160.9	$ 95.8

LIQUIDITY AND CAPITAL RESOURCES

Disruption to Functioning of Capital Markets

Multiple events during 2008 involving numerous financial institutions have effectively restricted current liquidity within the capital markets throughout the United States and around the world. Despite efforts by treasury and banking regulators in the United States, Europe and other nations around the world to provide liquidity to the financial sector, capital markets currently remain constrained. We expect that our ability to issue debt and equity at prices that are similar to offerings in recent years will be limited over the next three to six months and possibly longer should capital markets remain constrained. Although we intend to move forward with our planned internal growth projects, we may revise the timing and scope of these projects as necessary to adapt to existing economic conditions and the benefits expected to accrue to our unitholders from our expansion activities may be muted by substantial cost of capital increases during this period.

General

We believe that our ability to generate cash flow is sufficient to meet our current and future operating needs. Our primary operating cash requirements consist of normal operating expenses, core maintenance activities, distributions to our partners and payments associated with our derivative activities. We expect to fund our current and future short-term cash requirements from our operating cash flows. Margin requirements associated with our derivative transactions are generally supported by letters of credit issued under our Credit Facility.

Our current business strategy emphasizes developing and expanding our existing Liquids and Natural Gas businesses with less focus on acquisitions. Our need for investment capital to fund our expansion projects, make acquisitions of new assets and businesses and to retire maturing or callable debt obligations is expected to be funded from several sources. We anticipate initially funding long-term cash requirements for expansion projects and acquisitions first from operating cash flows, second, from borrowings under our commercial paper program and/or our Credit Facility, and lastly, from borrowings under our $500 million revolving credit agreement with Enbridge (U.S.) Inc., a wholly-owned subsidiary of Enbridge Inc. Likewise, we anticipate initially retiring our maturing and callable debt with similar borrowings on these existing

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facilities. We expect to obtain permanent financing through the issuance of additional equity and debt securities, which we will use to repay amounts initially drawn to fund these activities. Our ability to complete future debt and equity offerings and the timing of any such offerings will depend on various factors, including prevailing market conditions, interest rates, our financial condition and our credit rating at the time.

Capital Resources

Equity and Debt Securities

Execution of our growth strategy and completion of our planned construction projects contemplate our accessing the public and private equity and credit markets to obtain the capital necessary to fund these projects. Although we have generated in excess of $2.2 billion over the past two years through the issuance of a balanced combination of debt and equity securities to fund our expansion projects, our ability to access these markets to obtain permanent financing over the next three to twelve months is likely to be limited due to prevailing market conditions. Our planned internal growth projects continue to require us to bear the cost of constructing these new assets before we begin to realize a return on them. As a result, we will continue to be opportunistic in our approach to funding the remaining expenditures from additional issuances of our capital and long-term debt.

In March 2008, we obtained approximately $221.8 million of cash from the public issuance and sale of 4.6 million of our Class A common units at a price to the public of $49.00 per unit, which consisted of $217.2 million of net proceeds, after payment of underwriters' discounts, commissions and offering expenses and a contribution of $4.6 million from our general partner to maintain its two percent general partner interest. Additionally, in early April 2008, we completed the private issuance and sale of our $400 million Notes due 2018 and our $400 million Notes due 2038 for net proceeds of approximately $790.2 million, after payment of initial purchasers' discounts and offering expenses. The Notes due 2018 bear interest at the rate of 6.50% and the Notes due 2038 bear interest at the rate of 7.50%. We used a portion of the proceeds from these offerings to repay outstanding issuances of commercial paper and borrowings under our Credit Facility, which we had previously used to finance a portion of our capital expansion projects. We temporarily invested the remaining proceeds for use in future periods to fund additional expenditures under our capital expansion programs.

Available Credit

Two primary sources of our liquidity are provided by the commercial paper market and our Credit Facility. We have a $600 million commercial paper program that is supported by our long-term Credit Facility, which we access primarily to provide temporary financing for our operating activities, capital expenditures and acquisitions, at rates that in the past have been generally more competitive than the rates available under our Credit Facility. In addition to our Credit Facility and commercial paper program, we have access to a $500 million unsecured three year revolving credit agreement from Enbridge (U.S.) Inc., a wholly-owned subsidiary of Enbridge Inc.

Credit markets in the United States and around the world remain constrained due to a lack of liquidity and confidence in a number of financial institutions. Investors continue to seek perceived safe investments in securities of the United States government rather than corporate issues. Although the credit ratings assigned to our senior unsecured debt securities by the nationally recognized statistical ratings organizations are considered "investment grade," we may at times experience difficulty accessing the commercial paper and long-term credit markets due to prevailing market conditions. Additionally, existing constraints in the commercial paper and credit markets may increase the rates we are charged for utilizing these markets. Notwithstanding the continuing weakness in the United States credit markets, we expect that our available liquidity is sufficient to meet our operating and capital requirements into 2009 and for the foreseeable future.

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Credit Facility

A subsidiary of Lehman Brothers Holdings, Inc. ("Lehman"), Lehman Brothers Bank, FSB ("Lehman BB") is one of the committed lenders under our Credit Facility. On September 15, 2008, Lehman filed a petition under Chapter 11 of the U.S. Bankruptcy Code with the U.S. Bankruptcy Court for the Southern District of New York. Lehman BB has declined requests to honor its commitment to lend up to $82.5 million under our Credit Facility, effectively reducing the amount available to us under our Credit Facility to $1,167.5 million. We are working with other financial institutions to assume Lehman BB's commitment. The remaining lenders under our Credit Facility continue to honor our requests for funding and we believe the amounts available to us under our Credit Facility will continue to provide us with sufficient liquidity to meet our working capital needs.

The amounts we can borrow under the terms of our Credit Facility are reduced by the principal amount of our commercial paper issuances and the balance of our letters of credit outstanding. At September 30, 2008, we had $386.2 million outstanding under our Credit Facility at a weighted average interest rate of 3.82% and letters of credit totaling $101.2 million.

At September 30, 2008, we could borrow $490.1 million under the terms of our Credit Facility, determined as follows:

		September 30, 2008
		(in millions)
Total credit available under Credit Facility		$ 1,250.0
Less:	Amounts outstanding under Credit Facility	(386.2)
	Balance of letters of credit outstanding	(101.2)
	Principal amount of commercial paper issuances	(190.0)
	Lehman Brothers Bank, FSB commitment	(82.5)
Total amount we could borrow at September 30, 2008		$ 490.1

In March 2008, we requested and received approval from the parties named as lenders to our Credit Facility for a one year extension of the maturity date of the Credit Facility from April 4, 2012 to April 4, 2013.

Commercial Paper Program

At September 30, 2008, we had $190 million in principal amount of commercial paper outstanding, with unamortized discount of $0.5 million, at a weighted average interest rate of 3.19%, before the effect of our interest rate hedging activities. Under our commercial paper program, we had net repayments of approximately $79.4 million during the nine months ended September 30, 2008, which include gross issuances of $1,603.9 million and gross repayments of $1,683.3 million. At September 30, 2008, we could issue an additional $410 million in principal amount under our commercial paper program. The commercial paper we can issue is limited by the credit available under our Credit Facility.

EUS Credit Agreement

In addition to our Credit Facility and commercial paper program, we have access to an unsecured three year revolving credit agreement with Enbridge (U.S.) Inc., a wholly-owned subsidiary of Enbridge Inc. (the "EUS Credit Agreement"). The EUS Credit Agreement provides us with access to an additional $500 million of financing on substantially the same terms as our Credit Facility and matures in December 2010. The amounts available to us under the EUS Credit Agreement remain undrawn at September 30, 2008 and available for our use.

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The credit markets, including the commercial paper markets in the United States, have recently experienced adverse conditions. Continuing volatility in the capital markets may increase costs associated with issuing commercial paper or other debt instruments or affect our ability to access those markets. Notwithstanding these adverse market conditions, we currently believe that current cash and cash generated by operations, together with access to external sources of funds as described above, will be sufficient to meet our operating and capital needs in the foreseeable future.

Cash Requirements for Future Growth

Capital Spending

We expect to make significant expenditures for the construction of additional natural gas and crude oil transportation infrastructure over the next three years. In 2008, we expect to spend approximately $1.6 billion on these and other projects with the expectation of realizing additional cash flows as projects are completed and placed in service. Our ability to fund these expenditures is dependent upon our ability to access the capital necessary to finance the construction of these facilities. Capital markets in the United States and abroad are constrained and as a result we may revise the timing and scope of these projects as necessary to adapt to existing markets and economic conditions.

Forecasted Expenditures

We categorize our capital expenditures as either core maintenance or enhancement expenditures. Core maintenance expenditures are those expenditures that are necessary to maintain the service capability of our existing assets and include the replacement of system components and equipment which is worn, obsolete or completing its useful life. Enhancement expenditures improve the service capability of our existing assets, extend asset useful lives, increase capacities from existing levels, reduce costs or enhance revenues, and enable us to respond to governmental regulations and developing industry standards.

We estimate our capital expenditures based upon our strategic operating and growth plans, which are also dependent upon our ability to produce or otherwise obtain the capital necessary to accomplish our growth objectives. The following table sets forth our estimates of capital required for system enhancement and core maintenance expenditures through December 31, 2008. Although we anticipate making the indicated expenditures, these estimates may change due to factors beyond our control, including weather-related issues, construction timing, changes in supplier prices or poor economic conditions. Additionally, estimates may change as a result of decisions made at a later date to revise the scope of a project. We made capital expenditures of $1.0 billion, including $49.3 million for core maintenance activities, during the nine months ended September 30, 2008.

For the full year of 2008, we anticipate our capital expenditures to approximate the following in billions:

System enhancements	$0.5
Core maintenance activities	0.1
Southern Access expansion	0.8
Alberta Clipper	0.2
	$1.6

Major Construction Projects

The following table includes our active major construction projects and additional information regarding our estimated construction cost, actual expenditures through September 30, 2008, the incremental capacity that will become available upon completion of the project and the periods during

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which we expect to complete the construction. The projected amounts included in this table may change due to modifications of the scope of the project, increases in materials and construction costs and other factors that are outside of our direct control.

	Capital Expenditures		Estimated Incremental Capacity			
	Estimated Total Cost	Actual Expenditures through September 30, 2008	Storage[(1)]	Oil[(2)]	Natural Gas[(3)]	Expected Completion
	(in billions)					
Southern Access expansion (Lakehead)	$ 2.1	$ 1.7	—	400	—	2009
Clarity (East Texas)	0.6	0.6	—	—	700	2008
Alberta Clipper	1.2	0.1	—	450	—	Mid-2010
North Dakota phase 6 expansion	0.2	—	—	50	—	Early 2010
Griffith and Superior storage tanks	0.1	—	1,220	—	—	2008
Trailbreaker	0.3	—	—	—	—	2012
Total	$ 4.5	$ 2.4	1,220	900	700	

(1) Thousands of barrels (KBbl).

(2) Thousands of barrels per day (Kbpd).

(3) Millions Of cubic feet per day (MMcf/d).

At September 30, 2008, we have approximately $573.2 million in outstanding purchase commitments for materials and services associated with our capital projects for the construction of assets that we expect to settle during the remainder of 2008 and into 2009. However, we will incur additional commitments as our capital projects continue to progress.

Including major expansion projects and excluding acquisitions, ongoing capital expenditures are expected to be significant over the next three years due to our Southern Access expansion and Alberta Clipper projects. Core maintenance capital is also anticipated to increase over that period of time due to growth in our pipeline systems and aging of infrastructure.

We anticipate funding the system enhancement capital expenditures temporarily through the issuance of commercial paper or borrowing under the terms of our Credit Facility, with permanent debt and equity funding being obtained when appropriate. Core maintenance expenditures are expected to be funded by operating cash flows.

We expect to incur continuing annual capital and operating expenditures for pipeline integrity measures to ensure both regulatory compliance and to maintain the overall integrity of our pipeline systems. Expenditure levels have continued to increase as pipelines age and require higher levels of inspection or maintenance; however, these are viewed to be consistent with industry trends.

Derivative Activities

We use derivative instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to mitigate the volatility of our cash flows and manage the risks associated with market fluctuations in commodity prices. Based on our risk management policies, all of our derivative instruments are employed in connection with an underlying asset, liability or anticipated transaction and are not entered into with the objective of speculating on commodity prices.

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The following table provides summarized information about the timing and expected settlement amounts of our outstanding commodity derivative instruments at September 30, 2008:

	Notional	2008	2009	2010	2011	2012	2013	Total
				(dollars, in millions)				
Swaps								
Natural gas[1]	314,776,128	$(21.8)	$(42.0)	$(41.1)	$(33.2)	$(7.0)	$1.1	$(144.0)
NGL[2]	8,029,873	(18.5)	(43.2)	(7.0)	(0.5)	4.6	—	(64.6)
Crude[2]	1,345,324	(5.3)	(11.4)	(7.9)	(7.6)	(5.8)	1.1	(36.9)
Options-calls								
Natural gas[1]	1,187,000	(0.3)	(1.4)	(1.5)	(1.4)	—	—	(4.6)
NGL[2]	9,486	—	—	—	—	—	—	—
Options-puts								
Natural gas[1]	1,310,000	0.6	—	—	—	—	—	0.6
NGL[2]	1,087,300	0.4	1.0	2.3	1.5	2.6	—	7.8
Totals		$(44.9)	$(97.0)	$(55.2)	$(41.2)	$(5.6)	$2.2	$(241.7)

(1) Notional amounts for natural gas are recorded in MMBtu.

(2) Notional amounts for NGL and Crude are recorded in Bbl.

Operating Activities

Net cash provided by operating activities for the nine months ended September 30, 2008 was $473.2 million, an increase of $55.3 million from the $417.9 million generated during the same period in 2007. The increase in operating cash flow is directly attributable to the improved operating performance of our Liquids and Natural Gas systems. Although net cash provided by operating activities increased, cash flows associated with changes in our working capital accounts for the nine months ended September 30, 2008 were lower than the same period of 2007 due to the general timing differences in the collection on and payment of our current and related party accounts.

Investing Activities

We used $294.8 million less in our investing activities during the nine months ended September 30, 2008 in relation to the same period in 2007. The decrease is primarily attributable to the $315.8 million reduction of amounts spent in the first nine months of 2008 on our construction projects as compared to the same period of 2007. The decrease in the amounts spent on our construction projects is primarily attributable to completion of our Clarity project and the first stage of our Southern Access expansion project.

Financing Activities

Net cash provided by financing activities during the nine months ended September 30, 2008 was $707.1 million, compared with $920.9 million for the corresponding period in 2007. The reduction in the amount of cash provided by financing activities is due primarily to the lower amount of cash generated from our unit issuances in the first nine months of 2008 when compared to the same period in 2007. Net cash provided by financing activities for the nine months ended September 30, 2008 is attributable to the following:

- $221.8 million we raised in March 2008 from the issuance of 4.6 million class A common units, which consisted of $217.2 million of net proceeds after underwriters' discounts, commissions and offering expenses, and a contribution of $4.6 million from our general partner to maintain its two percent general partner interest.

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- In early April 2008, we completed the private issuance and sale of our $400 million Notes due 2018 and our $400 million Notes due 2038 for net proceeds of approximately $790.2 million, after payment of initial purchasers' discounts and offering expenses.

The increase in cash raised from both our unit and debt issuances is partially offset by the following:

- $93.1 million of net repayments on our Credit Facility and commercial paper.

- $32.3 million more distributions to our partners for the first nine months of 2008 compared to the same period in 2007 due to a greater number of units outstanding, a higher distribution level and higher incentive distribution payments to our general partner.

For the nine months ended September 30, 2008 we had gross borrowings of $2,131.3 million under our Credit Facility and gross repayments of $2,145.0 million, including $490.0 million of non-cash borrowings and repayments. Under our commercial paper program we had gross issuances of $1,603.9 million and gross repayments $1,683.3 million during the first nine months of 2008.

OFF-BALANCE SHEET ARRANGEMENTS

We have no significant off-balance sheet arrangements.

SUBSEQUENT EVENTS

Distribution to Partners

On October 13, 2008, the Board of Directors of Enbridge Management declared a distribution payable to our partners on November 14, 2008. The distribution will be paid to unitholders of record as of November 6, 2008, of our available cash of $108.8 million at September 30, 2008, or $0.990 per common unit. Of this distribution, $74.9 million will be paid in cash, $14.3 million will be distributed in i-units to our i-unitholder, $18.9 million will be distributed in Class C units to the holders of our Class C units and $0.7 million will be retained from the General Partner in respect of the i-unit and Class C unit distributions.

REGULATORY MATTERS

FERC Transportation Tariffs—Liquids

Effective July 1, 2008, we increased our rates for transportation on our Lakehead, North Dakota and Ozark systems in accordance with the indexed rate ceilings allowed by the FERC. In March 2006, the FERC determined that the Producer Price Index For Finished Goods plus 1.3 percent (PPI + 1.3 percent) should be the oil pricing index for a five year period ending July 2011. The index is used to establish rate ceiling levels for oil pipeline rate changes. For our Lakehead system, indexing only applies to the base rates, and does not apply to the SEP II, Terrace and Facilities surcharges. Effective July 2008, we increased the base tariff rates on our Lakehead system by an average of 8.2 percent to equal the indexed ceiling level allowed under the FERC's indexing methodology. On our Lakehead system, the new average rate for crude oil movements from the International Border near Neche, North Dakota to Chicago, Illinois is $1.26 per barrel, which reflects a $0.05 per barrel increase over the rates filed effective April 1, 2008. In addition to the rates on our Lakehead system, we increased the transportation rates on our North Dakota and Ozark systems 5.2 percent. The tariff rates for our Lakehead, North Dakota and Ozark systems are at the ceiling levels allowed under the FERC methodology.

Effective April 1, 2008, we filed our annual tariff with the FERC to reflect true-ups for the difference between estimates and actual cost and throughput data for the prior year and our projected costs and throughput for 2008. The projected costs for 2008 include four projects including the first stage of the Southern Access mainline expansion, two Superior and Griffith terminal tank projects and the Clearbrook Manifold project. This filing increased the average tariff for crude oil movements from the Canadian

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border to Chicago, Illinois, by approximately $0.34 per barrel, to an average of approximately $1.21 per barrel. We began to realize revenues in relation to this increased surcharge as crude oil is delivered from our pipeline, generally the month following the effective date of the tariff.

OTHER MATTERS

We amended our limited partnership agreement to modify the mechanism by which the capital accounts of all our partners are maintained when our general partner's incentive distribution rights are considered in determining the fair market value of the Partnership's assets in the event of a follow-on offering of our common units. We do not expect the amendment to materially change the amount of net taxable income or loss allocated to our unitholders or the economic rights of our unitholders as compared with the allocations or economic rights of our general partner.

RECENT ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

Disclosures about Derivative Instruments and Hedging Activities

In March 2008, the Financial Accounting Standard Board, or FASB, issued Statement No. 161, *Disclosures about Derivative Instruments and Hedging Activities*, which is effective for fiscal years and interim periods beginning after November 15, 2008. The statement requires qualitative disclosures about a company's strategies and objectives for using derivatives, quantitative disclosures about fair value gains and losses on derivatives, and disclosures of credit-risk-related contingent features in derivative instruments. We do not anticipate adopting the provisions of this pronouncement early. We do not expect our adoption of this pronouncement to have a material affect on our financial statements other than modifications to our existing derivative disclosures to conform to the requirements set forth in the statement.

Calculation of Earnings Per Unit

In March 2008, the Emerging Issues Task Force, or EITF reached consensus on EITF Issue No. 07-4, *Application of the Two-Class Method under FASB Statement No. 128 to Master Limited Partnerships*. The pronouncement prescribes the manner in which a master limited partnership, or MLP, should allocate and present earnings per unit using the two-class method set forth in FASB Statement No. 128, *Earning per Share*. Under the two-class method, current period earnings are allocated to the general partner (including any embedded incentive distribution rights) and limited partners according to the distribution formula for available cash set forth in the partnership agreement. To the extent the partnership agreement does not explicitly limit distributions to the general partner; any earnings in excess of distributions are to be allocated to the general partner and limited partners utilizing the distribution formula for available cash specified in the partnership agreement. When current period distributions are in excess of earnings, the excess distributions are to be allocated to the general partner and limited partners based on their respective sharing of losses specified in the partnership agreement for the period. EITF 07-4 is to be applied retrospectively for all financial statements presented and is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. Earlier application is not permitted. We expect to adopt EITF 07-4 for our quarter ending March 31, 2009. We are currently evaluating the affect this pronouncement will have on our present computation of earnings per unit.

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Item 3. Quantitative and Qualitative Disclosures About Market Risk

The following should be read in conjunction with the information presented in our Annual Report on Form 10-K for the year ended December 31, 2007, in addition to information presented in Items 1 and 2 of this Quarterly Report on Form 10-Q. There have been no material changes to that information other than as presented below.

Our net income and cash flows are subject to volatility stemming from changes in commodity prices of natural gas, NGLs, condensate and fractionation margins (the relative price differential between NGL sales and the offsetting natural gas purchases). Our exposure to commodity price risk exists within our Natural Gas and Marketing segments. To mitigate the volatility of our cash flows, we use derivative instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to manage the risks associated with market fluctuations in commodity prices. Based on our risk management policies, all of our derivative instruments are employed in connection with an underlying asset, liability or forecasted transaction and are not entered into with the objective of speculating on commodity prices.

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The following tables provides information about our derivative instruments at September 30, 2008 and December 31, 2007, with respect to our commodity price risk management activities for natural gas and NGLs, including condensate:

	At September 30, 2008						At December 31, 2007	
			Wtd. Average Price[2]		Fair Value[3]		Fair Value[3]	
	Commodity	Notional[1]	Receive	Pay	Asset	Liability	Asset	Liability
Contract maturing in 2008								
Swaps								
Receive variable/pay fixed	Natural Gas	8,542,547	$ 6.20	$ 7.62	$ 0.9	$ (13.0)	$ 7.6	$ (14.5)
	NGL	30,000	88.10	87.44	0.1	(0.1)	—	—
Receive fixed/pay variable	Natural Gas	7,670,290	6.68	6.72	8.2	(8.6)	10.3	(39.8)
	NGL	1,452,036	42.37	55.24	0.5	(19.0)	—	(98.9)
	Crude Oil	137,824	61.68	100.48	—	(5.3)	—	(17.7)
Receive variable/pay variable	Natural Gas	51,956,969	6.80	6.98	6.2	(15.5)	7.0	(3.5)
Options								
Calls (written)	Natural Gas	92,000	4.31	7.62	—	(0.3)	—	(1.3)
Calls (purchased)	NGL	9,486	53.53	53.19	—	—	—	—
Puts (purchased)	Natural Gas	215,000	9.05	6.85	0.6	—	—	—
	NGL	136,896	57.41	46.47	0.4	—	0.1	—
Contract maturing in 2009								
Swaps								
Receive variable/pay fixed	Natural Gas	16,187,681	$ 7.47	$ 8.18	$ 3.4	$ (14.5)	$ 5.5	$ (1.6)
	NGL	176,870	60.94	63.69	0.1	(0.6)	—	—
Receive fixed/pay variable	Natural Gas	18,471,215	6.43	7.88	12.4	(38.4)	1.2	(41.8)
	NGL	3,735,045	46.19	57.94	5.9	(48.6)	—	(43.6)
	Crude Oil	354,625	69.29	102.46	—	(11.4)	—	(7.2)
Receive variable/pay variable	Natural Gas	104,153,403	7.68	7.73	5.8	(10.7)	2.9	(1.8)
Options								
Calls (written)	Natural Gas	365,000	4.31	8.15	—	(1.4)	—	(1.5)
Puts (purchased)	Natural Gas	365,000	8.15	3.40	—	—	—	—
	NGL	566,072	55.51	46.00	1.9	(0.9)	0.6	—
Contract maturing in 2010								
Swaps								
Receive variable/pay fixed	Natural Gas	3,713,769	$ 8.11	$ 7.55	$ 4.5	$ (2.6)	$ 4.4	$ —
	NGL	45,625	50.59	57.63	—	(0.3)	—	—
Receive fixed/pay variable	Natural Gas	10,048,870	4.40	8.45	0.7	(39.1)	—	(38.0)
	NGL	1,513,655	49.12	53.78	7.5	(14.2)	—	(13.8)
	Crude Oil	332,150	79.29	104.75	1.3	(9.2)	—	(4.4)
Receive variable/pay variable	Natural Gas	64,375,000	8.30	8.38	0.7	(5.3)	1.5	(0.7)
Options								
Calls (written)	Natural Gas	365,000	4.31	8.57	—	(1.5)	—	(1.4)
Puts (purchased)	Natural Gas	365,000	8.57	3.40	—	—	—	—
	NGL	172,280	59.23	53.37	2.3	—	—	—
Contract maturing in 2011								
Swaps								
Receive variable/pay fixed	Natural Gas	1,598,755	$ 8.37	$ 6.97	$ 3.3	$ (1.3)	$ 3.2	$ —
Receive fixed/pay variable	Natural Gas	7,955,920	3.63	8.53	—	(35.3)	—	(34.1)
	NGL	581,810	55.84	56.81	4.1	(4.6)	—	(4.3)
	Crude Oil	228,125	68.36	105.35	—	(7.6)	—	(3.4)
Receive variable/pay variable	Natural Gas	15,885,000	8.63	8.62	0.5	(0.4)	0.1	—
Options								
Calls (written)	Natural Gas	365,000	4.31	8.54	—	(1.4)	—	(1.4)
Puts (purchased)	Natural Gas	365,000	8.54	3.40	—	—	—	—
	NGL	83,220	63.34	51.53	1.5	—	—	—
Contract maturing in 2012								
Swaps								
Receive variable/pay fixed	Natural Gas	941,709	$ 8.33	$ 8.72	$ 0.9	$ (1.2)	$ 0.9	$ —
	NGL	36,600	50.28	55.58	—	(0.2)	—	—
Receive fixed/pay variable	Natural Gas	1,456,000	3.57	9.05	—	(7.0)	—	(6.8)
	NGL	458,232	70.56	58.26	4.8	—	—	—
	Crude Oil	219,600	74.85	105.75	—	(5.8)	—	(1.9)
Receive variable/pay variable	Natural Gas	1,089,000	8.20	7.90	0.3	—	—	—
Options								
Puts (purchased)	NGL	128,832	66.80	54.10	2.6	—	—	—
Contract maturing after 2012								
Swaps								
Receive fixed/pay variable	Natural Gas	730,000	$ 9.83	$ 8.00	$ 1.1	$ —	$ —	$ —
	Crude Oil	73,000	124.05	106.12	1.1	—	—	—

(1) Volumes of Natural gas are measured in MMBtu, whereas volumes of NGL and Crude are measured in Bbl.

(2) Weighted average prices received and paid are in $/MMBtu for Natural gas and in $/Bbl for NGL and Crude.

(3) The fair value is determined based on quoted market prices at September 30, 2008 and December 31, 2007, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values are presented in millions of dollars.

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Our credit exposure for over-the-counter derivatives is directly with our counterparty and continues until the maturity or termination of the contract. When appropriate, valuations are adjusted for various factors such as credit and liquidity considerations.

The table below summarizes our derivative balances by counterparty credit quality in millions of dollars (negative amounts represent our net obligations to pay the counterparty).

	September 30, 2008	December 31, 2007
	(in millions)	
Counterparty Credit Quality*		
AAA	$ —	$ —
AA	(164.0)	(298.3)
A	(76.4)	(47.2)
Lower than A	—	—
Total	$ (240.4)	$ (345.5)

* As determined by nationally recognized statistical ratings organizations.

Item 4. Controls and Procedures

We and Enbridge maintain systems of disclosure controls and procedures designed to provide reasonable assurance that we are able to record, process, summarize and report the information required in our annual and quarterly reports under the Securities Exchange Act of 1934. Our management has evaluated the effectiveness of our disclosure controls and procedures as of September 30, 2008. Based upon that evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures are effective to accomplish their purpose. In conducting this assessment, our management relied on similar evaluations conducted by employees of Enbridge affiliates who provide certain treasury, accounting and other services on our behalf. We have not made any changes that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting during the three months ended September 30, 2008.

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PART II—OTHER INFORMATION

Item 1. Legal Proceedings

Refer to Part I, Item 1. Financial statements, Note 9, which is incorporated herein by reference.

Item 1A. Risk Factors

The risk factors presented below update and should be considered in addition to the risk factors previously disclosed in our Annual Report on Form 10-K for the fiscal year ended December 31, 2007.

Our ability to access the credit and capital markets on attractive terms to obtain funding for our capital projects may be limited due to the deterioration of these markets.

Global financial markets and economic conditions have been, and continue to be, weak and volatile which has caused a substantial deterioration in the credit and capital markets. These conditions, along with significant write-offs in the financial services sector and the re-pricing of credit risk have made, and will likely continue to make, it difficult to obtain funding for our capital needs from the credit and capital markets on terms similar to recent debt and equity offerings.

In particular, the cost of raising money in the debt and equity capital markets has increased while the availability of funds from those markets has diminished. Also, as a result of concern about the stability of financial markets generally and the solvency of counterparties specifically, the cost of obtaining money from the credit markets has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards and reduced and, in some cases, ceased to provide funding to borrowers.

The commercial paper markets have recently experienced increased volatility and disruption, resulting in higher costs to issue commercial paper, which has resulted in a reduction in our use of our commercial paper program. In addition, because of the recent downturn in the financial markets, including the issues surrounding the solvency of many institutional lenders and the recent failure of several banks, our ability to obtain capital from our Credit Facility may be impaired. For example, as a result of Lehman Brothers Holding, Inc. ("Lehman") filing a petition under Chapter 11 of the U.S. Bankruptcy Code, Lehman Brothers Bank FSB ("Lehman BB"), a subsidiary of Lehman and a committed lender under our Credit Facility, has declined requests to honor its commitment to lend up to $82.5 million under our Credit Facility, effectively reducing the amount available to us under our Credit Facility to $1,167.5 million. We may be unable to utilize the full borrowing capacity under our Credit Facility if other lenders are not willing to provide additional funding to make up the portion of the Credit Facility commitments that Lehman BB has refused to fund or if any of the remaining 13 committed lenders is unable or unwilling to fund their respective portion of any funding request we make under our Credit Facility.

Due to these factors, we cannot be certain that funding for our capital needs will be available from the credit and capital markets if needed and to the extent required, on acceptable terms. If funding is not available when needed, or is available only on unfavorable terms, we may be unable to implement our development plan, enhance our existing business, complete acquisitions or otherwise take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our revenues and results of operations.

Our planned construction and development activities require substantial capital. We may be unable to obtain needed capital or financing on satisfactory terms or at all, which could delay or curtail our planned construction projects.

We have made and expect to continue making substantial capital expenditures for the construction and development of crude oil and natural gas infrastructure. One of the primary uses of our capital resources is expenditures for our pipeline construction and expansion projects. We invested approximately

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$1.9 billion in 2007 and anticipate investing approximately $1.6 billion during 2008 on our construction and development activities.

We intend to finance our future capital expenditures initially from our cash flow from operations, second from borrowings under our commercial paper program or our Credit Facility and lastly from borrowings under our $500 million revolving credit agreement with Enbridge (U.S.) Inc., a wholly-owned subsidiary of Enbridge Inc. As of September 30, 2008, our total debt outstanding was $3,736.3 million, we had $151.6 million available in unrestricted cash and short-term investments, $490.1 million of available borrowing capacity under our Credit Facility and the full $500 million available to us under our revolving credit agreement with Enbridge (U.S.) Inc. We expect to obtain permanent financing through the issuance of additional debt and equity securities, which we will use to repay amounts initially drawn to fund our construction and development activities. We may be unable to issue additional debt or equity securities, or to issue these securities on attractive terms due to a number of factors including a lack of demand, poor economic conditions, unfavorable interest rates or our financial condition or credit rating at the time. In the event additional capital resources are unavailable; we may curtail construction and development activities, or be forced to sell some of our assets on an untimely or unfavorable basis in order to raise capital.

Item 6. Exhibits

Reference is made to the "Index of Exhibits" following the signature page, which we hereby incorporate into this Item.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

		ENBRIDGE ENERGY PARTNERS, L.P. **(Registrant)**
	By:	Enbridge Energy Management, L.L.C. as delegate of Enbridge Energy Company, Inc. as General Partner
Date: October 31, 2008	By:	/s/ STEPHEN J. J. LETWIN
		Stephen J. J. Letwin *Managing Director* *(Principal Executive Officer)*
Date: October 31, 2008	By:	/s/ MARK A. MAKI
		Mark A. Maki *Vice President—Finance* *(Principal Financial Officer)*

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Index of Exhibits

Each exhibit identified below is filed as part of this document. Exhibits not incorporated by reference to a prior filing are designated by an "*"; all exhibits not so designated are incorporated herein by reference to a previous filing as indicated.

Exhibit Number	Description
3.1	Certificate of Limited Partnership of the Partnership (incorporated by reference to Exhibit 3.1 to the Partnership's Registration Statement No. 33-43425).
3.2	Certificate of Amendment to Certificate of Limited Partnership of the Partnership (incorporated by reference to Exhibit 3.2 to the Partnership's 2000 Form 10-K/A dated October 9, 2001).
3.3	Fourth Amended and Restated Agreement of Limited Partnership of the Partnership, dated August 15, 2006 (incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K dated August 16, 2006).
3.4	Amendment No. 1 to the Fourth Amended and Restated Agreement of Limited Partnership of the Partnership dated December 28, 2007 (incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K dated January 3, 2008).
3.5	Amendment No. 2 to the Fourth Amended and Restated Agreement of the Limited Partnership of the Partnership dated August 6, 2008 (incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K dated August 6, 2008).
4.1	Form of Certificate representing Class A Common Units (incorporated by reference to Exhibit 4.1 to the Partnership's 2000 Form 10-K/A dated October 9, 2001).
31.1*	Certification of Principal Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Principal Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certification of Principal Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2*	Certification of Principal Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

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Section 2: 10-Q (10-Q)

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Section 3: EX-31.1 (EX-31.1)

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Exhibit 31.1

CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Stephen J. J. Letwin, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Enbridge Energy Partners, L.P.;

2. Based on my knowledge, this quarterly report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this quarterly report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this quarterly report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this quarterly report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this quarterly report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this quarterly report based on such evaluation; and

   d) disclosed in this quarterly report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's Board of Directors (or persons performing the equivalent functions):

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 31, 2008 By: /s/ STEPHEN J. J. LETWIN

Stephen J. J. Letwin
Managing Director
(Principal Executive Officer)

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Section 4: EX-31.2 (EX-31.2)

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Exhibit 31.2

CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Mark A. Maki, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Enbridge Energy Partners, L.P.;

2. Based on my knowledge, this quarterly report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this quarterly report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this quarterly report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this quarterly report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this quarterly report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this quarterly report based on such evaluation; and

   d) disclosed in this quarterly report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's Board of Directors (or persons performing the equivalent functions):

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 31, 2008 By: /s/ MARK A. MAKI

Mark A. Maki

Vice President—Finance
(Principal Financial Officer)

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Section 5: EX-32.1 (EX-32.1)

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Exhibit 32.1

CERTIFICATE OF PRINCIPAL EXECUTIVE OFFICER
Pursuant to Section 906(a) of the Sarbanes-Oxley Act of 2002
Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18 United States Code

The undersigned, being the Principal Executive Officer of Enbridge Energy Partners, L.P. (the "Partnership"), hereby certifies that the Partnership's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2008, filed with the United States Securities and Exchange Commission pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)), fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, and that information contained in such Quarterly Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to the Partnership and will be retained by the Partnership and furnished to the Securities and Exchange Commission or its staff upon request.

Date: October 31, 2008 By: /s/ STEPHEN J. J. LETWIN

Stephen J. J. Letwin
Managing Director
(Principal Executive Officer)

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Section 6: EX-32.2 (EX-32.2)

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Exhibit 32.2

CERTIFICATE OF PRINCIPAL FINANCIAL OFFICER
Pursuant to Section 906(a) of the Sarbanes-Oxley Act of 2002
Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18 United States Code

The undersigned, being the Principal Financial Officer of Enbridge Energy Partners, L.P. (the "Partnership"), hereby certifies that the Partnership's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2008, filed with the United States Securities and Exchange Commission pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)), fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, and that information contained in such Quarterly Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to the Partnership and will be retained by the Partnership and furnished to the Securities and Exchange Commission or its staff upon request.

Date: October 31, 2008

By: /s/ MARK A. MAKI

Mark A. Maki
Vice President—Finance
(Principal Financial Officer)

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EEP 10-K 12/31/2007

Section 1: 10-K (10-K)

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended DECEMBER 31, 2007

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission File Number: 1-10934

ENBRIDGE ENERGY PARTNERS, L.P.
(Exact name of Registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**39-1715850** (I.R.S. Employer Identification No.)

1100 Louisiana
Suite 3300
Houston, Texas 77002
(Address of principal executive offices and zip code)

(713) 821-2000
(Registrant's telephone number, including area code)
Securities registered pursuant to Section 12(b) of the Act:

Title of each class	**Name of each exchange on which registered**

Class A Common Units	**New York Stock Exchange**

Securities registered pursuant to Section 12(g) of the Act: NONE

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large Accelerated Filer ☒	Accelerated Filer ☐
Non-Accelerated Filer ☐	Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

The aggregate market value of the Registrant's Class A Common Units held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of June 30, 2007, was $3,067,260,854.

As of February 20, 2008 the Registrant has 55,238,834 Class A common units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE: NONE

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This Annual Report on Form 10-K contains forward-looking statements. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. They use words such as "anticipate," "believe," "continue," "estimate," "expect," "forecast," "intend," "may," "plan," "position," "projection," "strategy," "could," "should," or "will" or the negative of those terms or other variations of them or comparable terminology. In particular, statements, expressed or implied, concerning future actions, conditions or events or future operating results or the ability to generate revenue, income or cash flow are forward-looking statements. Forward-looking statements are not guarantees of performance. They involve risks, uncertainties and assumptions. Future actions, conditions or events and future results of operations may differ materially from those expressed in these forward-looking statements. Many of the factors that will determine these results are beyond our ability to control or predict. For additional discussion of risks, uncertainties and assumptions, see "Item 1A. Risk Factors" included elsewhere in this Form 10-K.

Glossary

The following abbreviations, acronyms, or terms used in this Form 10-K are defined below:

AEUB	Alberta Energy and Utilities Board
Anadarko system	Natural gas gathering and processing assets located in western Oklahoma and the Texas panhandle, which were acquired on October 17, 2002
AOCI	Accumulated other comprehensive income
AOSP	Athabasca Oil Sands Project, located in northern Alberta, Canada
Bbl	Barrel of liquids (approximately 42 U.S. gallons)
BlackRock	BlackRock Ventures Inc., an unrelated producer of heavy oil in Western Canada
Bpd	Barrels per day
CAA	Clean Air Act
Canadian Natural	Canadian Natural Resources Limited, an unrelated energy company
CAPP	Canadian Association of Petroleum Producers, a trade association representing a majority of our Lakehead system's customers
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CAD	Amount denominated in Canadian dollars
CWA	Clean Water Act
DOT	Department of Transportation
East Texas system	Natural gas gathering, treating and processing assets in East Texas acquired on November 30, 2001. Also includes a system formerly known as the Northeast Texas system acquired October 17, 2002.
Enbridge	Enbridge Inc., of Calgary, Alberta, Canada, the ultimate parent of the General Partner
Enbridge Management	Enbridge Energy Management, L.L.C.
Enbridge system	Canadian portion of the System
Enbridge Pipelines	Enbridge Pipelines Inc.
EnCana	EnCana Corporation, an unrelated producer of natural gas and crude oil
EP Act	Energy Policy Act of 1992
EPACT	Energy Policy Act of 2005
EPA	Environmental Protection Agency
Exchange Act	Securities Exchange Act of 1934, as amended
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
General Partner	Enbridge Energy Company, Inc., general partner of the Partnership
HCA	High consequence area
ICA	Interstate Commerce Act
KPC	Kansas Pipeline system, sold on November 1, 2007
Lakehead Partnership	Enbridge Energy, Limited Partnership, a subsidiary of the Partnership
Lakehead system	U.S. portion of the System
LIBOR	London Interbank Offered Rate—British Bankers Association's average settlement rate for deposits in U.S. dollars
M^3	Cubic meters of liquid = 6.2898105 Bbl
MLP	Master Limited Partnership
MMBtu/d	Million British Thermal units per day
MMcf/d	Million cubic feet per day
Midcoast system	Natural gas gathering, treating, processing, transmission and marketing assets acquired October 17, 2002

Mid-Continent system	Crude oil pipelines and storage facilities located in the mid-continent of the U.S. and acquired on March 1, 2004
NEB	National Energy Board, a Canadian federal agency that regulates Canada's energy industry
NGA	Natural Gas Act
NGL or NGLs	Natural gas liquids
NGPA	Natural Gas Policy Act
NOPR	Notice of Proposed Rulemaking issued by the FERC.
North Dakota system	Liquids petroleum pipeline system in the Upper Midwest United States acquired on May 18, 2001
Northeast Texas system	Natural gas gathering and processing assets acquired on October 17, 2002 and integrated with the East Texas system
North Texas system	Natural gas gathering and processing assets acquired on December 31, 2003
NYMEX	The New York Mercantile Exchange where natural gas futures, options contracts, and other energy futures are traded
NYSE	New York Stock Exchange
OCSLA	Outer Continental Shelf Lands Act
OSHA	Occupational Safety and Health Administration
OPA	Oil Pollution Act
OPS	Office of Pipeline Safety
PADD	Petroleum Administration for Defense Districts
PADD I	Consists of Connecticut, Delaware, District of Columbia, Florida, Georgia, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, North Carolina, Pennsylvania, Rhode Island, South Carolina, Vermont, Virginia and West Virginia
PADD II	Consists of Illinois, Indiana, Iowa, Kansas, Kentucky, Michigan, Minnesota, Missouri, Nebraska, North Dakota, Ohio, Oklahoma, South Dakota, Tennessee and Wisconsin
PADD III	Consists of Alabama, Arkansas, Louisiana, Mississippi, New Mexico and Texas
PADD IV	Consists of Idaho, Montana, Wyoming and Colorado
PADD V	Consists of Washington, Oregon, California, Arizona, Alaska, Hawaii and Nevada
Palo Duro system	Natural gas transmission and gathering pipeline assets located in Texas between the Anadarko system and the North Texas system acquired on March 1, 2004 and integrated with the Anadarko system during 2005
Partnership Agreement	Fourth Amended and Restated Agreement of Limited Partnership of the Enbridge Energy Partners, L.P.
Partnership	Enbridge Energy Partners, L.P. and its consolidated subsidiaries
PHMSA	Pipeline and Hazardous Materials Safety Administration (formerly OPS)
PIPES of 2006	Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006
PIPES Act	Pipeline Safety Act Reauthorization of 2006
PPIFG	Producer Price Index for Finished Goods
PSA	Pipeline Safety Act
PSI Act	Pipeline Safety Improvement Act
RCRA	Resource Conservation & Recovery Act
SAGD	Steam assisted gravity drainage
SEC	Securities and Exchange Commission
SEP II	System Expansion Program II, an expansion program on the Lakehead system
Settlement Agreement	A FERC approved settlement agreement, signed October 1996

SFAS	Statement of Financial Accounting Standards
SFPP	Santa Fe Pacific Pipelines, L.P., an unrelated pipeline company
Suncor	Suncor Energy Inc., an unrelated energy company
Syncrude	Syncrude Canada Ltd., an unrelated energy company
Synthetic crude oil	Product that results from upgrading or blending bitumen into a crude oil stream which can be readily refined by most conventional refineries
System	The combined liquid petroleum pipeline operations of the Lakehead system and the Enbridge system
Tariff Agreement	A 1998 offer of settlement filed with the FERC
Terrace	Terrace Expansion Program, an expansion program on the Lakehead system
WCSB	Western Canadian Sedimentary Basin

PART I

Item 1.—Business

OVERVIEW

In this report, unless the context requires otherwise, references to "we," "us," "our," or the "Partnership" are intended to mean Enbridge Energy Partners, L.P. and its consolidated subsidiaries. We are a publicly traded Delaware limited partnership that owns and operates crude oil and liquid petroleum transportation and storage assets, and natural gas gathering, treating, processing, transportation and marketing assets in the United States of America. Our Class A common units are traded on the NYSE under the symbol "EEP."

We were formed in 1991 by our general partner to own and operate the Lakehead system, which is the U.S. portion of a crude oil and liquid petroleum pipeline system extending from western Canada through the upper and lower Great Lakes region of the United States to eastern Canada. A subsidiary of Enbridge owns the Canadian portion of the System. Enbridge, which is based in Calgary, Alberta, provides energy transportation, distribution and related services in North America and internationally. Enbridge is the ultimate parent of our general partner.

We are a geographically and operationally diversified partnership consisting of interests and assets relating to the midstream energy sector. As of December 31, 2007, our portfolio of assets include the following:

- Approximately 5,000 miles of crude oil gathering and transportation lines and 28.9 million barrels, or Bbl, of crude oil storage and terminaling capacity.
- Natural gas gathering and transportation lines totaling approximately 11,500 miles.
- Ten active natural gas treating and 24 active natural gas processing facilities with an aggregate capacity of approximately 2,800 million cubic feet per day, or MMcf/d.
- Trucks, trailers and railcars for transporting natural gas liquids, or NGLs, crude oil and carbon dioxide.
- Marketing assets that provide natural gas supply, transmission, storage and sales services.

Enbridge Management is a Delaware limited liability company that was formed in May 2002 to manage our business and affairs. Under a delegation of control agreement, our general partner delegated substantially all of its power and authority to manage our business and affairs to Enbridge Management. Our general partner, through its direct ownership of the voting shares of Enbridge Management, elects all of the directors of Enbridge Management. Enbridge Management is the sole owner of a special class of our limited partner interests, which we refer to as "i-units."

Our ownership at December 31, 2007 is comprised of the following:

	2007
Class A common units owned by the public	59.6%
Class B common units owned by our general partner	4.2%
Class C units owned by our general partner	6.4%
Class C units owned by institutional investors	13.1%
i-units owned by Enbridge Management	14.7%
General Partner interest	2.0%
	100.0%

BUSINESS STRATEGY

Our primary objective is to provide stable and sustainable cash distributions to our unitholders, while maintaining a relatively low investment risk profile. Our business strategies focus on creating value for our customers, which we believe is the key to creating value for our investors. To accomplish our objective, we focus on the following key strategies:

1. Expand existing core asset platforms

    - We intend to develop and acquire energy transportation assets and related facilities that are complementary to our existing systems. Our core businesses provide plentiful opportunities to achieve our primary business objectives.

2. Develop new asset platforms

    - We plan to develop new gathering, processing, transportation and storage assets to meet customer needs, by expanding capacity into new markets with favorable supply and demand fundamentals.

3. Focus on operational excellence

    - We will continue to operate our existing infrastructure to maximize cost efficiencies, provide flexibility for our customers and ensure the capacity is reliable and available when required. We will focus on safety, environmental integrity, innovation and effective stakeholder relations.

In our current environment, our primary focus is on expanding and developing our existing assets. We continue to place relatively less emphasis on acquisitions than we have in past years due to:

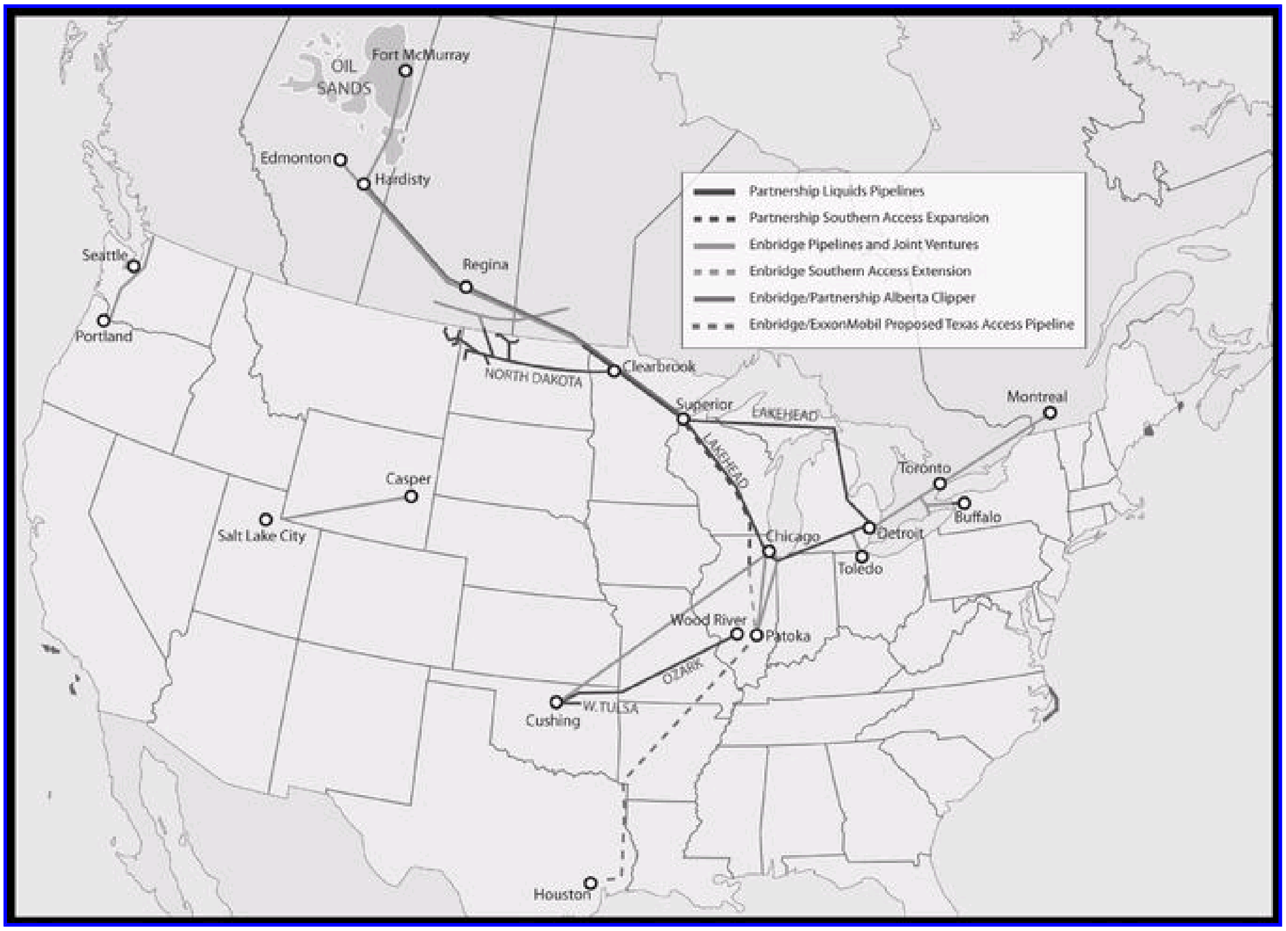
- Acquisition prices for the stable energy assets we seek continue to be inflated; and
- The expansion and diversification of our asset base over the past few years has created opportunities for internal growth projects that are expected to enhance the value of services we provide to our customers and returns to our investors.

While purchase prices remain high, our acquisitions will likely be limited to situations where we have natural advantages, through reduced costs or increased utilization of our services.

Our planned internal growth for both our liquids and natural gas businesses will require a significant investment of expansion capital over the next few years. While these major projects are under construction, we will bear the associated capital costs for these investments before we begin to realize a return on them. We expect our larger growth projects will be accretive to distributable cash flow when placed into service. These projects are discussed below in the respective business section.

Liquids

The following map presents the locations of our current Liquids systems assets and projects being constructed:



This map depicts some assets owned by Enbridge and projects being constructed to provide an understanding of how they interconnect with our Liquids systems.

Western Canadian crude oil is an important source of supply for the United States. According to the latest available data for 2007 from the U.S. Department of Energy's Energy Information Administration, Canada supplied approximately 1.7 million barrels per day, or Bpd, of crude oil to the U.S., the largest source of U.S. imports. Approximately 67 percent of the Canadian crude oil moving into the U.S. was transported on the System, the primary pipeline from western Canada to the U.S. We are well positioned to develop additional infrastructure to deliver growing volumes of crude oil that are expected from the Alberta oil sands. With an estimated $110 billion in Canadian dollars, or CAD, of active or planned projects in the Alberta oil sands, new production is expected to grow steadily during the next five years, with an additional 2.3 million Bpd of incremental supply available by 2015, according to the Canadian Association of Petroleum Producers, or CAPP.

Our Southern Access project is the cornerstone of our mainline expansion initiatives to address the expected increase in supply of Western Canadian crude oil. Our $2.1 billion project will provide an additional 400,000 Bpd of heavy crude oil capacity to the Chicago market and beyond by early 2009, with nearly half of this capacity available in early 2008. The design will also permit a further 800,000 Bpd increase in capacity for minimal additional cost, in conjunction with a corresponding expansion upstream of Superior. The Southern Access project involves new pipeline construction on our Lakehead system along with expansion on the Canadian portion of the pipeline by Enbridge.

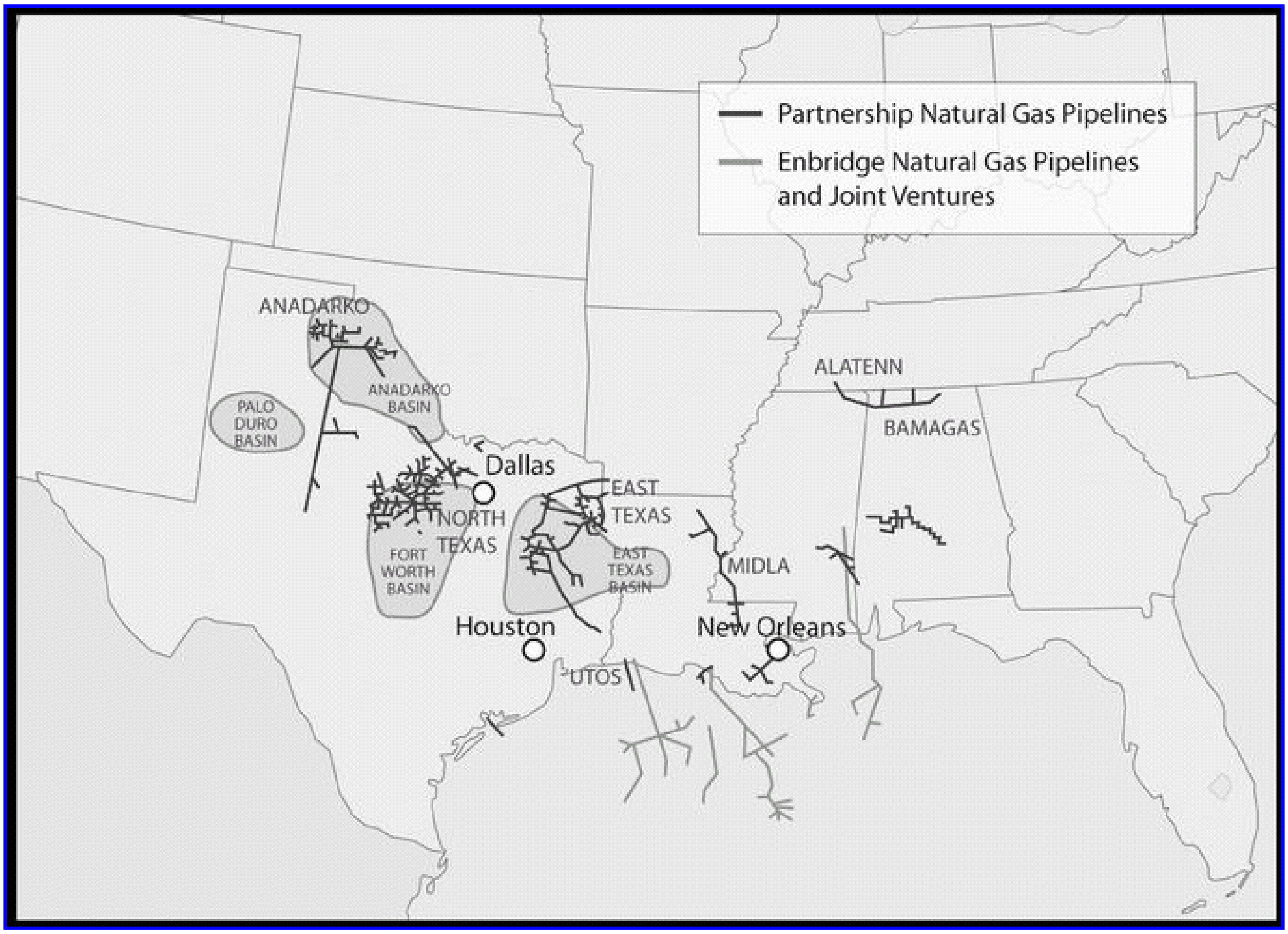
Additionally, we and Enbridge are developing the Alberta Clipper pipeline project, which will involve construction of a 1,000 mile, 36-inch diameter, heavy crude oil pipeline from Hardisty, Alberta to Superior, Wisconsin with an initial capacity of 450,000 Bpd that is expandable to 800,000 Bpd. Our share of the cost of this project as currently proposed will be approximately $1.0 billion in 2007 dollars, excluding capitalized interest. Alberta Clipper is expected to be in-service by the middle of 2010. Regulatory applications were filed with the National Energy Board in May 2007 for the Canadian segment of the project, and the hearings were concluded in the fourth quarter of 2007. In the United States, regulatory and permit applications are in progress at state and federal levels, and engineering and public consultations are underway.

Along with Enbridge, we are actively working with our customers to develop options that will allow Canadian crude oil to access new markets. The market strategy we are undertaking is to provide timely, economical, integrated transportation solutions to connect growing supplies of production from the Alberta oil sands to key refinery markets in the United States. The strategy involves further penetration into PADD II as well as entry into the vast refining center of the U.S. Gulf Coast. In December 2007, Enbridge and ExxonMobil Pipeline Company announced the two companies will conduct a Solicitation for Binding Shipper Commitment (Commitment Solicitation) for a proposed new pipeline system to transport crude oil from Patoka, Illinois, to the Texas Gulf Coast. The new pipeline to be called the "Texas Access Pipeline," would transport crude oil sourced from the Canadian oil sands region in Alberta, Canada, and from the upper Midwest to refiners in the Nederland and Houston, Texas areas. The proposed project includes a new 768-mile, 30-inch diameter pipeline, which would transport crude oil from Patoka, Illinois, southward to Nederland, Texas. Also proposed is an 88-mile, 24-inch pipeline to transport crude oil onward from Nederland to a delivery point in the east Houston area. The Commitment Solicitation is for shipper interest in executing binding commitments to transport specified volumes of crude oil on the new pipeline, which is expected to be completed in 2011. The results of the Commitment Solicitation will guide and determine the further development of the proposed joint venture pipeline.

The strategy of further penetration into PADD II is also evidenced by the Enbridge expansion of the Spearhead pipeline system from 125,000 Bpd to 190,000 Bpd. Our Lakehead system carries Western Canadian crude oil as far as Chicago, where it is transferred to the Spearhead pipeline that runs from Chicago, Illinois to the refinery and storage hub located at Cushing, Oklahoma.

Natural Gas

The following map presents the locations of assets for our Natural Gas systems:



This map depicts some assets owned by Enbridge to provide an understanding of how they relate to our Natural Gas systems.

Our natural gas assets are primarily located in the U.S. Gulf Coast region, one of the most active natural gas producing areas in the United States. Three of our larger systems in Texas are located in basins that are experiencing consistent drilling and production growth. These core basins are known as the East Texas basin, the Fort Worth Basin and the Anadarko basin. Our focus has been on expanding the service capability of our existing assets and acquiring assets with strong growth prospects located in or near these areas where we already operate or have a competitive advantage.

One of our key goals is to become the premier midstream energy company in the U.S. Gulf Coast region. To achieve this end, the operations and commercial activities of our gathering and processing assets and intrastate pipelines are integrated to provide better service to our customers. From an operations perspective, our key strategies are to provide safe and reliable service at reasonable costs to our customers, enhance our reputation and capitalize on opportunities for attracting new customers. From a commercial perspective, our focus is to provide our customers with a greater value for their commodity. This latter objective we intend to achieve by increasing customer access to preferred natural gas markets. We have made significant progress on attaining this objective with construction of our East Texas Expansion project, otherwise known as Clarity, which includes an intrastate pipeline connecting our East Texas system at Bethel, Texas to multiple downstream interconnects and by physically connecting a number of our systems.

The aim is to be able to move significant quantities of natural gas from our Anadarko, North Texas and East Texas systems to the major market hubs in Texas and Louisiana, which Clarity provides. From these market hubs, natural gas can be used in the local Texas markets or transported to consumers in the Midwest, Northeast and Southeast United States.

Our Natural Gas business also includes trucking operations that we use to enhance the value of the NGLs produced at our processing plants by ensuring ready access to strategic markets. Our Marketing business provides us with the ability to maximize the value received for the natural gas we transport and purchase by identifying customers with consistent demand for natural gas.

The growth prospects in our core areas are primarily a result of strong commodity prices, rig utilization rates and improvements in technology to produce natural gas from tight sand and shale formations. As a result, many expansions and extensions have been made on three of our main gathering and processing systems in Texas, including well-connects, processing plant re-activations, new plant construction, added compression, new pipelines and treating plant re-activations.

We continue to work closely with our customers to provide natural gas transportation solutions to avoid shut-in natural gas production from insufficient transportation capacity. In January 2006, we announced an expansion and extension of our East Texas system to handle the strong growth occurring in East Texas natural gas production, particularly from the Bossier Sands and other regional producing formations. We coordinated extensively with our customers to develop and enhance access for growing Texas natural gas production to major markets in southeast Texas. We have firm volume commitments and acreage dedications on our Clarity project, which we believe by the end of 2008 will approximate 600 MMcf/d. The intrastate pipeline has 700 MMcf/day of capacity that will be available when construction is completed in early 2008 and additional compression is added in mid-2008. The project is designed to be expandable and is positioned for potential upstream and downstream extension.

In addition to the expansion of our transportation capacity to meet the needs of our customers, we have also expanded our processing and treating capacity on our three major systems to meet the growing demand for these services and to capture the additional revenue these services provide. In 2007 we added 195 MMcf/d of processing capacity with the commissioning of the Hidetown plant on our Anadarko system and the expansions of the Weatherford plant on our North Texas system. We added three hydrocarbon dewpoint control facilities with total capacity of 550 MMcf/d on our East Texas system at Carthage, Grapeland and Henderson, Texas to meet the increasingly more stringent natural gas pipeline transportation specifications. Lastly, we enhanced the ability of our 275 MMcf/d treating facility at Aker, Texas to handle additional sour gas being produced in the southeast Texas area and we commissioned our 200 MMcf/d treating facility at Marquez, Texas which feeds directly into the intrastate pipeline we are constructing in connection with our Clarity project.

BUSINESS SEGMENTS

We conduct our business through three business segments:

- Liquids;
- Natural Gas; and
- Marketing.

These segments have unique business activities that require different operating strategies. For information relating to revenues from external customers, operating income and total assets for each segment, refer to Note 16 of our consolidated financial statements beginning on page F-1 of this report.

Liquids Segment

Lakehead system

The Lakehead system consists primarily of a crude oil and liquid petroleum common carrier pipeline and terminal assets in the Great Lakes and Midwest regions of the United States. This system, together with the Enbridge system in Canada, forms the longest liquid petroleum pipeline system in the world. The System, which spans approximately 3,300 miles, has been in operation for over 50 years and is the primary transporter of crude oil and liquid petroleum from western Canada to the United States. The System serves all the major refining centers in the Great Lakes and Midwest regions of the United States and the Province of Ontario, Canada. We and Enbridge have undertaken the Southern Access, Alberta Clipper and other expansion projects to increase the capacity of the Lakehead and Enbridge mainline systems in an effort to capitalize on the expected increases in crude oil supplies from previously announced heavy crude oil and oil sands projects in the Province of Alberta, Canada.

Our Lakehead system is an interstate common carrier pipeline system regulated by the Federal Energy Regulatory Commission, or FERC. The Lakehead system spans a distance of approximately 1,900 miles, and consists of approximately 3,500 miles of pipe with diameters ranging from 12 inches to 48 inches, 60 pump station locations with a total of approximately 846,450 installed horsepower and 64 crude oil storage tanks with an aggregate capacity of approximately 11.6 million barrels. The System operates in a segregation, or batch mode, allowing the transport of 43 crude oil commodities including light, medium and heavy crude oil (including bitumen, which is a naturally occurring tar-like mixture of hydrocarbons), condensate and NGLs.

Customers. Our Lakehead system operates under month-to-month transportation arrangements with our shippers. During 2007, approximately 30 shippers tendered crude oil and liquid petroleum for delivery through the Lakehead system. We consider multiple companies that are controlled by a common entity to be a single shipper for purposes of determining the number of shippers delivering crude oil and liquid petroleum on our Lakehead system. Our customers include integrated oil companies, major independent oil producers, refiners and marketers.

Supply and Demand. Our Lakehead system is well positioned as the primary transporter of western Canadian crude oil and continues to benefit from the growing production of crude oil from the Alberta oil sands. Similar to U.S. domestic conventional crude oil production, western Canada's conventional crude oil production is declining. Over the last several years, development of the Alberta oil sands resource has more than offset declining conventional production. The NEB estimated that total production in 2007 from the Western Canadian Sedimentary Basin, or WCSB, averaged approximately 2.4 million Bpd compared with 2.3 million bpd in 2006. WCSB crude oil production is comparable with production from key OPEC members Kuwait and Venezuela.

Remaining established conventional oil reserves in western Canada were estimated to be approximately 3.7 billion barrels at the end of 2006. During 2006, the latest period for which data is available, approximately 66 percent of conventional production was replaced with reserve additions. Remaining established reserves from the Alberta oil sands as of the end of 2006 stand at approximately 173 billion barrels. Combined conventional and oil sands established reserves of approximately 179 billion barrels compares with Saudi Arabia's proved reserves of approximately 264 billion barrels.

According to the CAPP, an estimated $60 billion CAD has been spent on oil sands development from 1996 through 2006. A survey of CAPP members and oil sands developers estimate that oil producers may spend an additional $110 billion CAD by 2011, including all announced and planned oil sands projects. Although it is unlikely that all projects will proceed as planned, the investment already in place and the number and size of companies involved provides strong evidence of ongoing oil sands industry expansion. CAPP estimates future production from the Alberta oil sands will increase by more than 2.3 million barrels per day by 2015 based on a subset of currently approved applications and announced expansions.

The near-term growth in crude oil supply comes from the completion and consolidation of major expansion projects at existing synthetic crude oil upgraders and growth of bitumen production from both existing and new Steam Assisted Gravity Drainage, or SAGD facilities currently under construction. Over the next year, synthetic crude oil production is expected to increase by approximately 315,800 Bpd from the following sources:

- 46,300 Bpd from the start up of the first phase of the Heartland Upgrader by BA Energy Inc.
- 114,000 Bpd from the phase 1 start up by Canadian Natural Resources Limited of its Horizon Project Upgrader.
- 58,500 Bpd from the phase 1 start up the Long Lake Project upgrader by joint venture partners Nexen Inc. and OPTI Canada Inc.
- 97,000 Bpd from start up of the Millennium coker unit by Suncor Energy Inc.

Syncrude completed a 100,000 Bpd Stage 3 expansion in 2006, increasing total production capacity to 350,000 Bpd. However, the new Stage 3 coker suffered from a number of start-up issues that prevented Syncrude from attaining full utilization of its production capacity, even through 2007. Production for the year averaged approximately 304,000 Bpd. Syncrude's next expansion will de-bottleneck the current system to increase synthetic production by approximately 40,000 Bpd to approximately 390,000 Bpd by 2012.

Suncor completed its 35,000 Bpd expansion in late 2005 resulting in total upgrading capacity of 260,000 Bpd. Average synthetic production from the upgrader was 229,000 Bpd in 2007, lower than capacity as a result of the scheduled shutdown of one of two upgraders to allow the tie-in of new facilities related to a planned expansion. Suncor also received conditional approval from the AEUB for its proposed Voyageur expansion, which will increase synthetic production capacity to 550,000 Bpd by 2012. Over the next year, Suncor is planning to complete construction of an additional coker unit as part of its Millennium project, bringing an additional 97,000 Bpd of synthetic production to the market.

The Athabasca Oil Sands Project, or AOSP, owned by Shell Canada Limited (60%), Chevron Canada Limited (20%) and Marathon Oil Corporation (20%), is another oil sands project that reached full production capacity in 2004. The AOSP project moved forward with AEUB's conditional approval of the proposed AOSP Expansion 1 project in 2006. The AOSP Expansion 1 project aims to achieve an expansion from the current production capacity of 158,000 Bpd of synthetic crude oil to more than 249,000 Bpd by 2010.

Over the next two years, unblended bitumen production is expected to start, or increase, from more than ten individual projects that are coming on line. Notable projects include the expansions at Canadian Natural's Wolf Lake/Primrose area, ConocoPhillips' Surmont, Devon's Jackfish, EnCana's Foster Creek and Christiana Lake, Husky's Sunrise, Suncor's Firebag and Total's Josyln project. Based on the AEUB forecast, unblended bitumen production is expected to increase by roughly 38,000 Bpd by the end of 2008, more than offsetting the decline in conventional crude production.

Although the crude oil and liquid petroleum delivered through the Lakehead system primarily originates in oilfields in western Canada, the Lakehead system also receives approximately five percent of its receipts from domestic sources including:

- U.S. production at Clearbrook, Minnesota through a connection with the North Dakota system;
- U.S. production at Lewiston, Michigan; and
- both U.S. and offshore production in the Chicago area.

Based on forecasted growth in western Canadian crude oil production and completion of upgrader expansions and increased bitumen production, Lakehead system deliveries are expected to average 1.69 million Bpd in 2008 compared with 1.54 million Bpd in 2007. The estimated deliveries for 2008 are part of a forecast representing forward-looking information and are subject to risks, uncertainties, and factors beyond our control.

Our ability to increase deliveries and to expand our Lakehead system in the future will ultimately depend upon numerous factors. The investment levels and related development activities by crude oil producers in conventional and oil sands production directly impacts the level of supply from the WCSB. Investment levels are influenced by crude oil producers' expectations of crude oil and natural gas prices, future operating costs, and availability of markets for produced crude. Higher crude oil production from the WCSB should result in higher deliveries on the Lakehead system. Deliveries on the Lakehead system are also affected by periodic maintenance, turnarounds and other shutdowns at producing plants that supply crude oil to, or refineries that take delivery from, our Lakehead system.

We expect the demand for WCSB crude oil production will continue to increase in PADD II. Refinery configurations and crude oil requirements in PADD II continue to be an attractive market for Western Canadian supply. According to the U.S. Department of Energy's Energy Information Administration, 2007 demand for crude oil in PADD II declined slightly from 2006 with an average of 3.2 million Bpd. At the same time, production of crude oil within PADD II increased marginally by 12,000 Bpd to 469,000 Bpd. With the proximity of the WCSB to PADD II, the availability of capacity on the Lakehead system and limited alternative markets for WCSB production, we expect deliveries on the Lakehead system to increase along with increases in WCSB supply. Based on our industry survey, we expect refineries in the PADD II market to compete aggressively with new markets for access to the growing supply of crude oil from the WCSB.

In conjunction with Enbridge, we continue to progress on schedule with construction of the 400,000 Bpd Southern Access expansion project. We are undertaking the United States portion of the expansion on our Lakehead system. The first stage of construction is on schedule for completion in the first half of 2008 that will add approximately 190,000 Bpd. This stage of the project includes a new pipeline between Superior and Delavan, Wisconsin, along with pump station enhancements upstream and downstream of this segment. The second stage of the Southern Access expansion project will provide capacity and a new pipeline from Delavan to Flanagan, Illinois, with completion expected in the first half of 2009. Completion of the total Southern Access expansion project will create a 454-mile pipeline with approximately 400,000 Bpd of incremental capacity on our Lakehead system.

On March 16, 2006, the Federal Energy Regulatory Commission ("FERC") approved an Offer of Settlement with respect to rate principles for the Southern Access expansion, which were negotiated with CAPP. In July 2006, support from shippers and CAPP was obtained to increase the diameter of the new pipeline segment of the project from 36 inches to 42 inches. The larger diameter will not provide increased capacity in the near term but does increase the ultimate expansion capacity of the line from 800,000 Bpd to 1,200,000 Bpd with additional pumping horsepower. This improves future expansion opportunities for our Lakehead system. In the interim, shippers will absorb all of the incremental operating costs of the larger diameter pipe but will benefit from reduced power costs at higher throughput levels.

We anticipate the ultimate cost to complete our portion of the Southern Access project to approximate $2.1 billion. This estimate reflects our cost experience to date for labor, materials and rights-of-way. The risk to our unitholders resulting from any escalation of costs is largely mitigated by the cost of service tolling arrangement used for the project. Approximately 88 percent of cost overages will be included in the rate base, which forms the basis for determining our tariff rates for transportation. The remaining 12 percent of the project cost relates to installing larger pipe than required under current agreements, which we are financing in anticipation of future expansion opportunities.

In July 2006, Enbridge announced that it had received support from shippers and CAPP for its 36-inch diameter, 400,000 Bpd Southern Access Extension pipeline from Flanagan, Illinois to Patoka, Illinois. The extension will broaden the reach of the Enbridge/Lakehead mainline system to incremental markets accessible from the Patoka hub. The project will be undertaken by Enbridge; however, we will benefit from the incremental volumes moving through our Lakehead system to connect with this extension. The initial FERC Offer of Settlement filed in September 2006 was rejected by the FERC due to the rolled in rate design contained in the Offer of Settlement. However, as a result of the strong support for the project, Enbridge filed a second application with the FERC in the latter half of 2007 with an alternative tolling structure to address the initial opposition from the intervening parties. A decision by the FERC is expected in early 2008 to allow the project to continue on schedule, with a 2009 in-service date.

Forecasts of oil sands production growth developed by Enbridge, as well as by CAPP, indicate that additional export pipeline capacity out of Western Canada will be needed over and above projects currently under construction. As a result of these forecasts and support received from shippers, we and Enbridge are developing the Alberta Clipper project. This project involves construction of a 36-inch diameter 1,000 mile heavy crude oil pipeline from Hardisty, Alberta to Superior generally within or adjacent to our and Enbridge's existing rights-of-way. We will construct approximately 330 miles of the new pipeline from the International Border near Neche, North Dakota to Superior, and at the request of our customers, we have revised the scope to include a delivery connection at Clearbrook, Minnesota and an additional tank at Superior. Alberta Clipper will have an initial capacity of 450,000 Bpd and allows for expansions up to 800,000 Bpd by adding pumping stations. In addition, complementary capacity on the Southern Access 42-inch pipeline from Superior to Flanagan will be obtained by installing additional pump stations. We anticipate that our share of the construction cost for the United States segment of the project will approximate $1.0 billion (in 2007 dollars excluding capitalized interest). Alberta Clipper is expected to be in service by mid-2010.

In May 2007, Enbridge filed an application with Canada's National Energy Board, or NEB, for the construction and operation of the Canadian segment of the project. In June 2007 Enbridge filed supplements to this application setting forth the tolling principles of the Canadian portion of the project, which are supported by CAPP and the hearings were concluded in the forth quarter of 2007. The United States regulatory and permit applications are in progress at state and federal levels. Enbridge is also progressing with land access, engineering and initial procurement commitments to facilitate commencement of project construction.

In another effort to provide shippers access to new markets, Enbridge acquired a pipeline that runs from Chicago to Cushing. The pipeline, renamed Spearhead, began delivering Canadian crude oil to the major oil hub at Cushing in March 2006 and has operated at or near its capacity of 125,000 Bpd. We have benefited from Western Canadian crude oil being carried on our Lakehead system as far as Chicago, and then transferred to the Spearhead pipeline. On March 2, 2007, Enbridge initiated a binding open season for expansion of the pipeline to 190,000 Bpd, which was successfully concluded in late April with receipt of binding commitments for capacity in excess of 30,000 Bpd. Preliminary engineering design has been completed, and the expansion is expected to be completed by early 2009. This project will be complementary to our Lakehead system.

In April 2006, ExxonMobil announced it had completed the reversal of two of its crude oil pipelines allowing up to 66,000 Bpd of Canadian crude oil to flow from Patoka, Illinois to the U.S. Gulf Coast. The pipeline is linked to our Lakehead system at Chicago via the Mustang Pipe Line Partners system to Patoka, Illinois. The Mustang system is 30% owned by an affiliate of Enbridge. ExxonMobil has received firm commitments from Canadian shippers for an average of 50,000 Bpd of capacity on the lines from Patoka, to Nederland, Texas for the next five years. The connection of our Lakehead system with this new market should also support increased throughput on our Lakehead system, although the reversed ExxonMobil system is also capable of transporting western Canadian crude oil moved via other competing pipelines into the Patoka market.

In December 2007, Enbridge and ExxonMobil Pipeline Company announced that they will jointly conduct a Solicitation for Binding Shipper Commitment for a proposed new pipeline system, to transport crude oil from Patoka, Illinois, to the Texas Gulf Coast. The new pipeline, to be called the "Texas Access

Pipeline," will transport crude oil sourced from the Canadian oil sands region in Alberta, Canada, and from the upper Midwest to refiners in the Nederland and Houston, Texas areas. The proposed project includes a new 768-mile, 30-inch diameter pipeline, which would transport crude oil from Patoka, Illinois, southward to Nederland, Texas. Also proposed is an 88-mile, 24-inch pipeline to transport crude oil onward from Nederland to a delivery point in the east Houston area. The Commitment Solicitation is for shipper interest in executing binding commitments to transport specified volumes of crude oil on the new pipeline, which is expected to be completed in 2011. The results of the Commitment Solicitation will guide and determine the further development of the proposed joint venture pipeline project.

Competition. Our Lakehead system, along with the Enbridge system, is the main crude oil export route from the WCSB. WCSB production in excess of western Canadian demand moves on existing pipelines into the Midwest area of the United States (PADD II), the Rocky Mountain states (PADD IV), the Anacortes area of Washington State (PADD V), and the U.S. Gulf Coast (PADD III). In each of these regions, WCSB crude oil competes with local and imported crude oil. As local crude oil production declines and refineries demand more imported crude oil, imports from the WCSB should increase.

For 2007, the latest data available shows that PADD II total demand was 3.2 million Bpd while it produced only 469,000 Bpd, and thus imported 2.7 million Bpd. The latest available data for 2007 indicate PADD II imported approximately 1.1 million Bpd of crude oil from Canada, a majority of which was transported on our Lakehead system to destinations in PADD II and to other pipeline systems with PADD III destinations. The remaining 1.6 million Bpd was imported from PADDs III and IV as well as from offshore sources through the U.S. Gulf Coast. Lakehead system deliveries of Canadian crude oil to PADD II were level with delivery volumes for 2006. Total deliveries on our Lakehead system averaged 1.53 million Bpd in 2007, meeting approximately 71 percent of Minnesota refinery capacity; 60 percent of the greater Chicago area; and 67 percent of Ontario's refinery demand.

Considering all of the pipeline systems that transport western Canadian crude oil out of Canada, the System transported approximately 67 percent of the total western Canadian crude oil exports in 2007 to the United States. The remaining production was transported by systems serving the British Columbia, PADD II, PADD IV, and PADD V markets.

Given the expected increase in crude oil production from the Alberta oil sands over the next 10 years, alternative transportation proposals have been presented to crude oil producers. These proposals range from expansions of existing pipelines that currently transport western Canadian crude oil, to new pipelines and extensions of existing pipelines. These proposals are in various stages of development, with some at the concept stage and others that are proceeding with regulatory approval. Some of these proposals could be in direct competition with our Lakehead system.

Enbridge has proposed construction of the Gateway Pipeline with an in-service date in the 2012 to 2014 timeframe, which includes both a condensate import pipeline and a petroleum export pipeline. The condensate line would transport imported diluent from Kitimat, British Columbia to the Edmonton, Alberta area. The petroleum export line would transport crude oil from the Edmonton area to Kitimat and would compete with our Lakehead system for production from the Alberta oil sands.

We and Enbridge believe that the Southern Access Expansion Program, the Alberta Clipper Project, and other initiatives to provide access to new markets in the Midwest, Mid-continent and Gulf Coast, offer flexible solutions to future transportation requirements of western Canadian crude oil producers, and the in-service timing of these solutions is in line with prospective shipper needs.

The following provides an overview of other proposals put forth by competing pipeline companies that are not affiliated with Enbridge:

- The construction of a new 24-inch pipeline alongside an existing pipeline which begins in Clearbrook, Minnesota and transports western Canadian crude oil to St. Paul, Minnesota. This expansion will have 165,000 Bpd initial capacity and 350,000 Bpd ultimate capacity. Construction began in summer 2007, with an anticipated completion date in 2008. While throughput on our Lakehead system would benefit from this expansion, volumes moving on our Lakehead system could be negatively impacted if the geographic reach of this pipeline were extended by reversing an existing Wood River to St. Paul pipeline.

- The expansion of an existing pipeline that runs from Alberta to British Columbia and Washington State. The first phase of this expansion to add 35,000 Bpd of capacity was approved by the NEB in 2005 and was recently completed. The second phase received NEB approval in October 2006, and would further increase capacity by another 40,000 Bpd by the end of 2008. Additional phases have also been proposed which would add substantial additional capacity, however, these proposed phases have not yet received shipper support.

- Construction of a new 435,000 Bpd crude oil pipeline from Hardisty, Alberta to Wood River and Patoka, with an expected in-service date of late 2009. This proposal has support of long-term contracts for a total of 340,000 Bpd. The sponsor company filed applications with the NEB in June 2006 to convert part of its mainline gas transmission facilities, and in December 2006, for approval to operate and construct facilities in Canada. Public hearings on the gas line transfer application were held in mid-November 2006 and in early 2007 the NEB approved transfer of the gas transmission facilities to crude oil service, and in September 2007 the NEB approved the application to construct and operate a 435,000 Bpd crude oil pipeline. Additional approvals will be required from United States and Canadian regulatory authorities before the project can proceed. A successful open season was held in the early part of 2007 for an expansion to 590,000 Bpd and an extension to Cushing, Oklahoma. A variety of regulatory approvals will be required in the United States at state and local levels before the proposal can proceed.

- Construction of new crude oil pipelines from northern Alberta directly to the U.S. Gulf Coast have been proposed by several different companies including Enbridge. These conceptual pipeline proposals are subject to shipper support and regulatory approval.

These competing alternatives for delivering western Canadian crude oil into the United States and other markets could erode shipper support for further expansion of our Lakehead system beyond the Southern Access Expansion and Extension projects and the Alberta Clipper Project. They could also affect throughput on and utilization of the System. However, the Lakehead and Enbridge systems offer significant cost savings and flexibility advantages, which are expected to continue to favor the System as the preferred alternative for meeting shipper transportation requirements to the Midwest United States and beyond.

The following table sets forth average deliveries per day and barrel miles of our Lakehead system for each of the periods presented.

	Deliveries				
	2007	2006	2005	2004	2003
	(thousands of Bpd)				
United States					
Light crude oil	346	327	241	275	258
Medium and heavy crude oil	852	872	791	785	741
NGL	4	5	4	4	4
Total United States	1,202	1,204	1,036	1,064	1,003
Ontario					
Light crude oil	184	160	146	174	174
Medium and heavy crude oil	62	63	59	81	68
NGL	95	90	98	103	109
Total Ontario	341	313	303	358	351
Total Deliveries	1,543	1,517	1,339	1,422	1,354
Barrel miles (billions per year)	408	400	338	367	345

Mid-Continent system

Our Mid-Continent system, which we acquired in the first quarter of 2004, is located within the PADD II district and is comprised of our Ozark pipeline, our West Tulsa pipeline and storage terminals at Cushing and El Dorado, Kansas. It includes over 480 miles of crude oil pipelines and 16.7 million barrels of crude oil storage capacity. Our Ozark pipeline transports crude oil from Cushing to Wood River where it delivers to ConocoPhillips' Wood River refinery and interconnects with the WoodPat Pipeline, and the Wood River Pipeline, each owned by unrelated parties. Our West Tulsa pipeline moves crude oil from Cushing to Tulsa, Oklahoma where it delivers to Sinclair Oil Corporation's Tulsa refinery.

The storage terminals consist of 104 individual storage tanks ranging in size from 55,000 to 575,000 barrels. We added a net of 7 new tanks during 2007 to our existing storage facilities in Cushing, which increased our crude oil storage capacity to 16.7 million. A portion of the storage facilities are used for operational purposes while we contract the remainder of the facilities with various crude oil market participants for their term storage requirements. Contract fees include fixed monthly capacity fees as well as utilization fees, which we charge for injecting crude oil into and withdrawing crude oil from the storage facilities.

Customers. Our Mid-Continent system operates under month-to-month transportation arrangements and both long-term and spot storage arrangements with its shippers. During 2007, approximately 40 shippers tendered crude oil for service by the Mid-Continent system. We consider multiple companies that are controlled by a common entity to be a single shipper for purposes of determining the number of shippers delivering crude oil and liquid petroleum on our Mid-Continent system. These customers include integrated oil companies, independent oil producers, refiners and marketers. Average deliveries on the system were 236,000 Bpd for 2007 and 244,000 Bpd for 2006.

Supply and Demand. The Mid-Continent system is positioned to capitalize on increasing near-term demand for imported crude oil from west Texas and the U.S. Gulf Coast as well as third-party storage demand. In 2007, PADD II imported 2.7 million Bpd from outside of the PADD II region. The Lakehead system supplied roughly 1.1 million Bpd of crude from Canada leaving 1.6 million Bpd imported from PADDs III and IV as well as offshore sources. We expect the gap between local supply and demand for crude oil in PADD II to continue to widen, encouraging imports of crude oil from Canada, PADD III, and foreign sources.

Competition. Our Ozark pipeline system currently serves an exclusive corridor between Cushing and Wood River. However, refineries connected to Wood River have crude supply options available from Canada via the Lakehead system, with a connection to the Mustang pipeline, an Enbridge affiliated system, and through a third party pipeline, which runs from western Canada and PADD IV. These same refineries also have access to U.S. Gulf Coast and foreign supply through the Capline pipeline system, which is an undivided joint interest pipeline that is owned by unrelated parties. In addition, refineries located east of Patoka with access to crude through the Ozark system, also have access to west Texas supply through the Texas Gulf pipeline owned by unrelated parties. The Ozark pipeline system could face a significant increase in competition if a proposed new pipeline from Hardisty, Alberta to Patoka is completed in 2009. However, if that situation occurs, we would consider potential alternative uses for our Ozark system.

In addition to movements into Wood River, crude oil in Cushing is transported to Chicago and El Dorado on third-party pipeline systems. With the reversal of the Spearhead pipeline, western Canadian crude oil moving on Spearhead is increasing the importance of Cushing as a terminal and pipeline origination area.

The storage terminals rely on demand for storage service from numerous oil market participants. Producers, refiners, marketers and traders rely on storage capacity for a number of different reasons: batch scheduling, stream quality control, inventory management, and speculative trading opportunities. Competitors to our storage facilities at Cushing include large integrated oil companies and other midstream energy partnerships.

North Dakota system

Our North Dakota system is a crude oil gathering and interstate transportation system servicing the Williston Basin in North Dakota and Montana. Its crude oil gathering pipelines collect crude oil from points near producing wells in approximately 22 oil fields in North Dakota and Montana. Most deliveries from the North Dakota system are made at Clearbrook, Minnesota, to the Lakehead system and to a third-party pipeline system. The North Dakota system includes approximately 330 miles of crude oil gathering lines connected to a transportation line that is approximately 620 miles long, with a capacity of approximately 110,000 Bpd. We recently completed a 30,000 Bpd increase in capacity resulting from a $78.2 million expansion of the system we began in 2006 and completed in December 2007. This expansion was necessary to meet increased crude oil production from the Montana and North Dakota region. We have also proposed an approximate $150 million additional expansion to further increase system capacity to 161,000 Bpd. The commercial structure for this expansion is a cost-of-service based surcharge that will be added to the existing tariff rates. The proposed surcharge is similar to the structure being used on the recently completed expansion project and is subject to approval from the FERC. The North Dakota system also has 21 pump stations, one delivery station, and 11 terminaling facilities with an aggregate working storage capacity of approximately 745,000 barrels.

Customers. Customers of the North Dakota system include producers of crude oil and purchasers of crude oil at the wellhead, such as marketers, that require crude oil gathering and transportation services. Producers range in size from small independent owner/operators to the largest integrated oil companies.

Supply and Demand. Like the Lakehead system, the North Dakota system depends upon demand for crude oil in the Great Lakes and Midwest regions of the United States, and the ability of crude oil producers to maintain their crude oil production and exploration activities.

Competition. Competitors of the North Dakota system include integrated oil companies, interstate and intrastate pipelines or their affiliates and other crude oil gatherers. Many crude oil producers in the oil fields served by the North Dakota system have alternative gathering facilities available to them or have the ability to build their own facilities.

Natural Gas Segment

We own and operate natural gas gathering, treating, processing and transportation systems as well as trucking operations. We purchase and gather natural gas from the wellhead, deliver it to plants for treating and/or processing and to intrastate or interstate pipelines for transmission to wholesale customers such as power plants, industrial customers and local distribution companies.

Natural gas treating involves the removal of hydrogen sulfide, carbon dioxide, water and other substances from raw natural gas so that it will meet the standards for pipeline transportation. Natural gas processing involves the separation of raw natural gas into residue gas and NGLs. Residue gas is the processed natural gas that ultimately is consumed by end users. NGLs separated from the raw natural gas are either sold and transported as NGL raw mix or further separated through a process known as fractionation, and sold as their individual components, including ethane, propane, butanes and natural gasoline. At December 31, 2007, we have 10 active treating plants and 24 active processing plants, including three hydrocarbon dewpoint control facilities, or HCDP plants. Our treating facilities have a combined capacity exceeding 1,050 MMcf/d while the combined capacity of our processing facilities approximates 1,800 MMcf/d, including 550 MMcf/d provided by the HCDP plants.

Our natural gas segment consists of the following systems:

- East Texas system: Includes approximately 3,800 miles of natural gas gathering and transportation pipelines, eight natural gas treating plants and seven natural gas processing plants, including three HCDP plants and approximately 250 miles associated with completed sections of our Clarity project.

- Anadarko system: Consists of approximately 1,700 miles of natural gas gathering and transportation pipelines in southwest Oklahoma and the Texas panhandle, one natural gas treating plant and six natural gas processing plants. The Anadarko system includes the Palo Duro system, which we acquired in March 2004.

- North Texas system: Includes approximately 4,500 miles of natural gas gathering pipelines and ten natural gas processing plants.

- Our transportation operations include three FERC-regulated natural gas interstate pipeline systems which include the Midla, AlaTenn and UTOS pipelines. Each of these natural gas pipeline systems typically consists of a natural gas pipeline, compression, and various interconnects to other pipelines that serve wholesale customers.

- Our transportation operations also include a number of smaller non-FERC regulated natural gas pipelines and plants as well as trucking operations which are discussed below.

Customers. Customers of our natural gas pipeline systems include both purchasers and producers of natural gas. Purchasers are comprised of marketers, including our Marketing business, and large users of natural gas, such as power plants, industrial facilities and local distribution companies. Producers served by our systems consist of small, medium and large independent operators and large integrated energy companies. We sell NGLs resulting from our processing activities to a variety of customers ranging from large petrochemical and refining companies to small regional retail propane distributors.

Our natural gas pipelines serve customers predominantly in the Gulf Coast and southeastern regions of the United States. Customers include large users of natural gas, such as power plants, industrial facilities, local distribution companies, large consumers seeking an alternative to their local distribution company, and shippers of natural gas, such as natural gas producers and marketers.

Supply and Demand. Demand for our gathering, treating and processing services primarily depends upon the supply of natural gas reserves and the drilling rate of new wells. The level of impurities in the natural gas gathered also affects treating services. Demand for these services also depends upon overall economic conditions and the prices of natural gas and NGLs. Our larger systems, Anadarko, East Texas and North Texas, are located in basins that continue to experience growth in natural gas drilling and production.

Our East Texas system is primarily located in the East Texas Basin. The Bossier trend, which is located on the western side of our East Texas system within the East Texas Basin, continues to experience substantial growth. Production in the Bossier trend has grown from under 390 MMcf/d in 1997 to over 1,500 MMcf/d in August 2007. During 2006, the link between our North Texas and East Texas systems became fully operational and increased the utilization of the 500 MMcf/d intrastate pipeline that we placed in service in June 2005 on our East Texas system by providing additional market access to customers of our North Texas system. In a further effort to address the continuing strong growth in natural gas production occurring in East Texas, in early 2006 we initiated a $635 million expansion and extension of our East Texas system named the Clarity project. During 2007, we completed the following segments of this expansion project:

- A 24-inch diameter pipeline that runs from the Marquez treating facility to Crockett, Texas and the 36-inch diameter pipeline that runs from Crockett to Goodrich, Texas were both completed and placed into service in late March 2007;

- The Marquez treating plant with capacity of approximately 200 MMcf/d and additional pipeline capacity to the existing southeast section of this area was completed and placed into service in March 2007;

- A 36-inch diameter pipeline that extends from an interconnect with our existing pipeline at Bethel, Texas to Crockett was completed and placed into service in late July 2007; and

- A 36-inch diameter pipeline that extends from Goodrich to Kountze, Texas, which enables deliveries into a major interstate pipeline was completed in October 2007.

We expect construction of the remaining segments that will connect natural gas supply from Bethel to Orange, Texas will be completed in the first quarter of 2008. Additional capacity to downstream interconnects will increase as compression is added through mid-2008. Completion of our Clarity project will provide service to major industrial companies in Southeast Texas with interconnects to interstate pipelines, intrastate pipelines and wholesale customers. We have firm volume commitments and acreage dedications which we believe will approximate 600 MMcf/d of the 700 MMcf/d of capacity by the end of 2008 and we continue to pursue additional commitments for capacity on the pipeline. The Clarity project is designed to be expandable and is positioned for potential upstream and downstream extension to meet the growing demand for natural gas transportation capacity.

We have also completed significant expansion of our treating and processing capacity in the region, which began in 2006 with the completion of our 120 MMcf/d Henderson natural gas processing facility. We completed the following additional facilities during 2007:

- Enhancement of our existing 275 MMcf/d Aker treating facility was completed in 2007 and additional expansions are underway at this facility in 2008;

- Construction of the Weatherford gas processing facility within our North Texas system was completed in September 2007 with a processing capacity of approximately 35 MMcf/d. At the end of 2007, additional processing capacity was added to increase its capacity from 35 MMcf/day to 75/MMcf/day.

- In the second half of 2007 we completed three HCDP plants totaling 550 MMcf/d of capacity within our East Texas system.

The gathering, treating, processing and transportation assets we have placed in service over the past several years on our East Texas system are well positioned to capture the growing supply of natural gas being produced in the region as a result of the improved access to primary natural gas markets provided by our Clarity project.

A substantial portion of natural gas on our North Texas system is produced in the Barnett Shale area within the Fort Worth Basin Conglomerate. The Fort Worth Basin Conglomerate is a mature zone that is experiencing slow production decline. In contrast, the Barnett Shale area is one of the most active natural gas plays in North America. While abundant natural gas reserves have been known to exist in the Barnett Shale area since the early 1980s, technological developments in fracturing the shale formation allows commercial production of these natural gas reserves. Based on the latest information available for 2007, Barnett Shale production has risen from approximately 110 MMcf/d in 1999 to over 2,900 MMcf/d in 2007, with the drilling of over 6,600 wells. We anticipate that throughput on the North Texas system will increase modestly in each of the next several years as a result of Barnett Shale development.

Our Anadarko system is located within the Anadarko basin and continues to experience considerable growth as a result of the rapid development of the Granite Wash play in Hemphill and Wheeler counties in Texas. We have expanded our natural gas processing capacity to approximately 445 MMcf/d at the end of 2007, with the addition of the Hidetown processing facility with 120 MMcf/d of capacity. We also continue to add field compression to accommodate the volume growth on this system.

We intend to expand our natural gas gathering and processing services primarily through internal growth projects designed to provide exposure to incremental supplies of natural gas at the wellhead, increase opportunities to serve additional customers, including new wholesale customers, and allow expansion of our treating and processing businesses. Additionally, we will pursue acquisitions to expand our natural gas services in situations where we have natural advantages to create additional value for our existing assets.

Our natural gas pipelines generally serve different geographical areas, with differing supply and demand characteristics in each market. We believe demand and competition for natural gas in the areas served by our natural gas assets will generally remain strong as a result of being located in areas where industrial, commercial or residential growth is occurring. The greatest demand for services in the markets served by our natural gas assets occurs in the winter months.

The table below indicates the capacity in MMcf/d of the transportation and wholesale customer pipelines with firm transportation contracts and the amount of capacity that is reserved under those contracts as of that date.

Major System	**Capacity MMcf/d**	**Percentage Reserved Under Contract as of December 31, 2007**
UTOS system	1,200	0%
Midla system	200	74%
AlaTenn system	200	28%
Bamagas system	450	61%

Our UTOS system transports natural gas from offshore platforms on a fee for service basis to other pipelines onshore for further delivery and does not have long-term contracts. The average daily throughput on our UTOS system during 2007 was 192,000 MMBtu/d. The FERC approved our negotiated settlement with UTOS shippers, keeping our current rates in effect under our 2003 FERC Order, through 2006. In February 2007, the FERC approved our application for an extension of that Order to keep the settlement rates in effect for an additional 3-year term through 2009.

Our Midla, AlaTenn and Bamagas systems primarily serve industrial corridors and power plants in Louisiana, Alabama and Tennessee. Industries in the area include energy intensive segments of the petrochemical and pulp and paper industries. We market the unused capacity on these systems under both short-term firm and interruptible transportation contracts and long-term firm transportation contracts. These systems are located in areas where opportunities exist to serve new industrial facilities and to make delivery interconnects to alleviate capacity constraints on other third-party pipeline systems. As of December 31, 2007, approximately 74 percent of contracted capacity of the Midla system and approximately 15 percent of the AlaTenn system is under contract to our marketing business. We recently initiated negotiations with a major customer of our Midla mainline transmission system for the renewal of a contract that is set to expire in August 2008. Although the ultimate outcome of these negotiations is uncertain, we may incur a non-cash impairment charge for this asset, if the customer elects not to renew the contract, or renews the contract on less favorable terms. We are also exploring alternative uses for this pipeline system.

The Bamagas system in northern Alabama is contiguous with our AlaTenn system and serves two power plants that are indirectly owned by Calpine Corporation ("Calpine"). In December 2005, Calpine Corporation ("Calpine") and many of its subsidiaries, including the subsidiary that owns the two utility plants served by our Bamagas system, filed voluntarily petitions to restructure under Chapter 11 of the United States Bankruptcy Code. Since filing for bankruptcy, Calpine has continued to perform under the terms of its agreements with Bamagas. In June 2007, Calpine and certain of its subsidiaries filed a Joint Plan of Reorganization and Disclosure Statement with the United States Bankruptcy Court. On December 19, 2007, the U.S. Bankruptcy Court for the Southern District of New York issued a decision confirming Calpine's reorganization plan. In addition, the Bamagas contracts with Calpine have been reaffirmed. Calpine announced at the end of January 2008 that it has emerged from Bankruptcy.

Our long-term financial condition depends on the continued availability of natural gas for transportation to the markets served by our systems. Existing customers may not extend their contracts if the availability of natural gas from the Mid-continent and Gulf Coast producing regions was to decline and if the cost of transporting natural gas from other producing regions through other pipelines into the areas we serve were to render the delivered cost of natural gas uneconomical. We may be unable to find additional customers to replace the lost demand or transportation fees.

Competition. Competition from other pipeline companies is significant in all the markets we serve. Competitors of our gathering, treating and processing systems include interstate and intrastate pipelines or their affiliates and other midstream businesses that gather, treat, process and market natural gas or NGLs. Some of these competitors are substantially larger than we are. Competition for the services we provide varies based upon the location of gathering, treating and processing facilities. Most natural gas producers and owners have alternate gathering, treating and processing facilities available to them. In addition, they have alternatives such as building their own gathering facilities or in some cases, selling their natural gas supplies without treating and processing. In addition to location, competition also varies based upon pricing arrangements and reputation. On the sour gas systems, such as our East Texas system, competition is more limited due to the infrastructure required to treat sour gas.

Competition for customers in the marketing of residue gas is based primarily upon the price of the delivered gas, the services offered by the seller and the reliability of the seller in making deliveries. Residue gas also competes on a price basis with alternative fuels such as crude oil and coal, especially for customers that have the capability of using these alternative fuels, and on the basis of local environmental considerations. Competition in the marketing of NGLs comes from other NGL marketing companies, producers, traders, chemical companies and other asset owners.

Because pipelines are generally the only practical mode of transportation for natural gas over land, the most significant competitors of our natural gas pipelines are other pipelines. Pipelines typically compete with each other based on location, capacity, price and reliability. Many of the large wholesale customers we serve have multiple pipelines connected or adjacent to their facilities. Accordingly, many of these customers have the ability to purchase natural gas directly from a number of pipelines or third parties that may hold capacity on the various pipelines. In addition, a number of new interstate natural gas pipelines are being constructed in areas currently served by some of our intrastate and interstate pipelines. When completed, these new pipelines may compete for customers with our existing pipelines.

Trucking and Liquids Marketing Operations

We also include our trucking and liquids marketing operations in our Natural Gas segment. Trucking and liquids marketing operations include the transportation of NGLs, crude oil and carbon dioxide by truck and railcar from wellheads and treating, processing and fractionation facilities and to wholesale customers, such as distributors, refiners and chemical facilities. In addition, our trucking and liquids marketing operations resell these products. A key component of our business is ensuring market access for the liquids extracted at our processing facilities. On average this accounts for approximately 43% of the volume transported by our trucking and liquids marketing business and is a major source of its growth in this area.

Our services are provided using trucks, trailers and rail cars, product treating and handling equipment and NGL storage facilities. In addition, our CO_2 plant, with 250 tons per day of capacity, takes excess CO_2 from hydrogen producers which we then sell to a variety of customers. We also have 50% ownership of an underground propane storage facility in Petal, Mississippi, which augments the services we provide to our customers in the region. The total capacity of this facility is 5.6 million Bbls which increases our storage capabilities.

We have increased the size of our truck fleet by approximately 25 percent since 2005 to meet the growing supply of NGLs, crude oil and carbon dioxide from our processing facilities, as well as to capitalize on the opportunity to better serve our Gulf Coast customers.

Customers. Most of the customers of our trucking and liquids marketing operations are wholesale customers, such as refineries and propane distributors. Our trucking and liquids marketing operations also market products to wholesale customers such as petrochemical plants.

Supply and Demand. The areas served by our trucking and liquids marketing operations are geographically diverse, and the forces that affect the supply of the products transported vary by region. Crude oil and natural gas prices and production levels affect the supply of these products. The demand for services is affected by the demand for NGLs and crude oil by large industrial refineries, and similar customers in the regions served by this business.

Competition. Our trucking and liquids marketing operations have a number of competitors, including other trucking and railcar operations, pipelines, and, to a lesser extent, marine transportation and alternative fuels. In addition, the marketing activities of our trucking and liquids marketing operations have numerous competitors, including marketers of all types and sizes, affiliates of pipelines and independent aggregators.

Marketing Segment

Our Marketing segment's primary objectives are to mitigate financial risk and maximize the value of the natural gas purchased by our gathering systems and the throughput on our gathering and intrastate wholesale customer pipelines. To achieve this objective, our Marketing segment transacts with various counterparties to provide natural gas supply, transportation, balancing, storage and sales services.

Since our gathering and intrastate wholesale customer pipeline assets are geographically located within Texas, Oklahoma, Alabama, Mississippi and Louisiana, the majority of activities conducted by our Marketing segment are focused within these areas.

Customers. Natural gas purchased by our Marketing segment is sold to industrial, utility and power plant end use customers. In addition, gas is sold to marketing companies at various market hubs. These sales are typically priced based upon a published daily or monthly price index. Sales to end-use customers incorporate a pass-through charge for costs of transportation and additional margin to compensate us for associated services.

Supply and Demand. Supply for our Marketing business depends to a large extent on the natural gas reserves and rate of drilling within the areas served by our Natural Gas segment. Demand is typically driven by weather-related factors with respect to power plant and utility customers, and industrial demand.

Our Marketing business uses third-party storage capacity to balance supply and demand factors within its portfolio. Marketing pays third-party storage facilities and pipelines for the right to store gas for various periods of time. These contracts may be denoted as firm storage, interruptible storage, or parking and lending services. These various contract structures are used to mitigate risk associated with sales and purchase contracts, and to take advantage of price differential opportunities. Due to the increased volumes from our gathering assets, our Marketing business leases third-party pipeline capacity downstream from our Natural Gas assets under firm transportation contracts following specific, controlled guidelines. This capacity is leased for various lengths of time and at rates that allow our Marketing business to diversify its customer base by expanding its service territory. Additionally, this transportation capacity provides assurance that our natural gas will not be shut in, which can result from capacity constraints on downstream pipelines.

Competition. Our Marketing segment has numerous competitors, including large natural gas marketing companies, marketing affiliates of pipelines, major oil and gas producers, independent aggregators and regional marketing companies.

REGULATION

FERC Allowance for Income Taxes in Interstate Common Carrier Pipeline Rates

In a 1995 decision involving our Lakehead system, which we refer to as the *Lakehead ruling*, the FERC partially disallowed the inclusion of income taxes in the cost of service for the Lakehead system. In its *Lakehead ruling*, the FERC allowed an oil pipeline publicly traded partnership to include in its cost-of-service an income tax allowance to the extent that its unitholders were corporations subject to income tax. A subsequent appeal of the *Lakehead ruling* was resolved by settlement and therefore was not adjudicated. In another FERC proceeding involving Santa Fe Pacific Pipeline, L.P. (SFPP), an unrelated pipeline entity, the FERC initially relied on its previous *Lakehead ruling* to hold that SFPP could not claim an income tax allowance for income attributable to non-corporate partners, both individuals and other entities. SFPP and other parties to the proceeding appealed the FERC's orders to the United States Court of Appeals for the District of Columbia Circuit, or the D.C. Circuit Court.

In a decision issued in July 2004, in *BP West Coast Products, LLC v. FERC*, which we refer to as the *BP West Coast decision*, the D.C. Circuit Court vacated the portion of the FERC decision regarding the proper tax allowance for SFPP and remanded the case to the FERC for further proceedings.

In May and June 2005, the FERC issued a policy statement, as well as an order on remand of *BP West* Coast (the SFPP order), respectively, in which it stated it will permit pipelines to include in cost-of-service a tax allowance to reflect actual or potential tax liability on their public utility income attributable to all partnership or limited liability company interests, if the ultimate owner of the interest has an actual or potential income tax liability on such income. Whether a pipeline's owners have such actual or potential income tax liability will be determined by the FERC on a case-by-case basis. The new policy entails rate risk due to the case-by-case review requirement.

In December 2005, the FERC issued its first case-specific review of the income tax allowance issue reaffirming its income tax allowance policy and directing the pipeline to provide certain evidence necessary to determine its income tax allowance. The FERC's *BP West Coast* remand decision and the new tax allowance policy were appealed to the D.C. Circuit Court.

In May 2007, the D.C. Circuit Court upheld the income tax allowance policy adopted by the FERC for master limited partnerships (MLPs) and other non-taxable entities. On the basis of the SFPP order, the D.C. Circuit Court concluded that the FERC's new policy statement applied to SFPP and resolved the principle defect of the Lakehead policy, which was the inadequately explained differential treatment of the tax liability of the individual and corporate partners. On that basis the D.C. Circuit Court affirmed the FERC's tax allowance policy as being reasonable and in accordance with the FERC's statutory discretion. As such, the D.C. Circuit Court affirmed that an allowance should be permitted on all partnership interests, or similar legal interest, if the owner of that interest has an actual or potential income tax liability on the public utility income earned though the interest. We believe all our applicable assets will be entitled to a tax allowance to the extent a pipeline's partners have income tax liability on the income they receive from the pipeline. In August 2007, the D.C. Circuit Court denied a request for rehearing of its May 2007 decision, and the decision is now final and cannot be appealed.

In December 2006, the FERC issued a new order addressing rates on one of the interstate oil pipelines of SFPP. In that order, the FERC addressed challenges to the policy statement raised by shippers in filings in another docket earlier in 2006. In the new order, the FERC refined its income tax allowance policy, and notably raised a new issue regarding the implication of the policy statement for publicly traded partnerships. The FERC noted that the tax deferral features of a publicly traded partnership may cause some investors to receive, for some indeterminate duration, cash distributions in excess of their taxable income, which the FERC characterized as a "tax savings." The FERC stated that it is concerned that this creates an opportunity for those investors to earn an additional return, funded by ratepayers. Responding to this concern, the FERC chose to adjust the pipeline's equity rate of return downward based on the percentage by which the publicly traded partnership's cash flow exceeded taxable income. On February 7, 2007, SFPP asked the FERC to reconsider this ruling. The ultimate outcome of this proceeding is not certain and could result in changes to the FERC's treatment of income tax allowances in cost of service rates and to potential adjustment in a future rate case of our pipelines' respective equity rates of return that underlie their rates to the extent that cash distributions in excess of taxable income are allowed to some unitholders. If the FERC were to disallow a substantial portion of our pipelines' income tax allowance, it may cause our rates to be set at a level that is different, and in some instances lower, than the level otherwise in effect.

FERC Regulation of Return on Equity for Master Limited Partnerships

On July 19, 2007, the FERC issued a proposed policy statement regarding the composition of proxy groups for determining the appropriate returns on equity for natural gas and oil pipelines. The proposed policy statement would permit the inclusion of MLPs in the proxy group for purposes of calculating returns on equity under the Discounted Cash Flow (DCF) analysis, a change from its prior view that MLPs had not been shown to be appropriate for such inclusion. Specifically, the FERC proposes that MLPs may be included in the proxy group *provided* that the DCF analysis recognizes as distributions only the pipeline's reported earnings, and not other sources of cash flow subject to distribution. According to the proposed policy statement, under the DCF analysis, the return on equity is calculated by adding the dividend or distribution yield (dividends divided by share/unit price) to the projected future growth rate of dividends or distributions (weighted one third for long-term growth of the economy as a whole and two-thirds short term growth as determined by analysts' five-year forecasts for the pipeline). The determination of which MLPs should be included will be made on a case by case basis, after a review of whether an MLP's earnings have been stable over a multi-year period. The FERC proposes to apply the final policy statement to all pipeline rate cases that have not completed the hearing phase as of the date the FERC issues the final policy statement and has requested comments on the proposed policy which were due in September 2007. The FERC's proposed policy statement is subject to change based on comments filed and therefore we cannot predict the scope of the final policy statement.

Accounting for Pipeline Assessment Costs

In June 2005, the FERC issued an order in Docket AI05-1 describing how FERC-regulated companies should account for costs associated with implementing the pipeline integrity management requirements of the United States Department of Transportation's Office of Pipeline Safety. The order took effect on January 1, 2006. Under the order, FERC-regulated companies are generally required to recognize costs incurred in performing pipeline assessments that are part of a pipeline integrity management program as maintenance expense in the period in which the costs are incurred. Costs for items such as rehabilitation projects designed to extend the useful life of the system can continue to be capitalized to the extent permitted under the existing rules. The FERC denied rehearing of its accounting guidance order on September 19, 2005.

We have historically capitalized first time in-line inspection programs, based on previous rulings by the FERC. In January 2006, we began expensing all first-time internal inspection costs for all our pipeline systems, whether or not they are subject to the FERC's regulation on a prospective basis. We will continue to expense secondary internal inspection tests consistent with our previous practice. Refer to Note 2—Summary of Significant Accounting Policies included in our consolidated financial statements beginning at page F-1 of this annual report on Form 10-K for additional discussion.

Regulation by the FERC of Interstate Common Carrier Liquids Pipelines

The Lakehead, North Dakota, and Ozark systems are our primary interstate common carrier liquids pipelines subject to regulation by the FERC under the Interstate Commerce Act, or ICA. As common carriers in interstate commerce, these pipelines provide service to any shipper who requests transportation services, provided that products tendered for transportation satisfy the conditions and specifications contained in the applicable tariff. The ICA generally requires us to maintain tariffs on file with the FERC that set forth the rates we charge for providing transportation services on our interstate common carrier pipelines, as well as the rules and regulations governing these services.

The ICA gives the FERC the authority to regulate the rates we charge for service on our interstate common carrier pipelines. The ICA requires, among other things, that such rates be "just and reasonable" as well as nondiscriminatory. The ICA permits interested persons to challenge newly proposed or changed rates and authorizes the FERC to suspend the effectiveness of such rates for a period of up to seven months and to investigate the rates to determine if they are just and reasonable. If, upon completion of an investigation, the FERC finds that the new or changed rate is unlawful, it is authorized to require the carrier to refund with interest the increased revenues in excess of the amount that would have been collected during the term of the investigation at the rate properly determined to be lawful. The FERC also may investigate, upon complaint, or on its own motion, rates that are already in effect and may order a carrier to change its rates prospectively. Upon an appropriate showing, a shipper may obtain reparations for damages sustained for a period of up to two years prior to the filing of a complaint.

On October 24, 1992, Congress passed the Energy Policy Act of 1992, or EP Act, which deemed petroleum pipeline rates that were in effect for the 365-day period ending on the date of enactment, or that were in effect on the 365^{th} day preceding enactment and had not been subject to complaint, protest or investigation during the 365 day period, to be just and reasonable under the ICA (i.e., "grandfathered"). The EP Act also limited the circumstances under which a complaint can be made against such grandfathered rates. In order to challenge grandfathered rates, a party must show, 1) that it was contractually barred from challenging the rates during the relevant 365 day period; 2) that there has been a substantial change after the date of enactment of the EP Act in the economic circumstances of the pipeline or in the nature of the services that were the basis for the rate; or 3) that the rate is unduly discriminatory or unduly preferential.

The FERC has determined that the Lakehead system rates are not covered by the grandfathering provisions of the EP Act because they were subject to challenge prior to the effective date of the statute.

We believe that the rates for the North Dakota and Ozark systems should be found to be largely covered by the grandfathering provisions of the EP Act.

The EP Act required the FERC to issue rules establishing a simplified and generally applicable ratemaking methodology for petroleum pipelines, and to streamline procedures in petroleum pipeline proceedings. The FERC responded to this mandate by issuing Order No. 561, which, among other things, adopted an indexing rate methodology for petroleum pipelines. Under the regulations, which became effective January 1, 1995, petroleum pipelines are able to change their rates within prescribed ceiling levels that are tied to an inflation index. Rate increases made within the ceiling levels may be protested, but such protests must show that the rate increase resulting from application of the index is substantially in excess of the pipeline's increase in costs. If the indexing methodology results in a reduced ceiling level that is lower than a pipeline's filed rate, Order No. 561 requires the pipeline to reduce its rate to comply with the lower ceiling, although a pipeline is not required to reduce its rate below the level grandfathered under the EP Act. Under Order No. 561, a pipeline must, as a general rule, utilize the indexing methodology to change its rates. The FERC, however, uses cost-of-service ratemaking, market-based rates and settlement rates as alternatives to the indexing approach in certain specified circumstances.

Under Order No. 561, the original inflation index adopted by the FERC was equal to the annual change in the Producer Price Index for Finished Goods, or PPI-FG, minus one percentage point. The index was subject to review every five years. Rates were then subject to an annual adjustment, based upon changes in the PPI-FG minus 1%, in order to accurately reflect the actual cost changes experienced by the oil pipeline industry. In December 2000, as part of the FERC's five-year review of the oil-pricing index (July 2001 through June 2006), the FERC concluded that the PPI-FG accurately reflected the actual cost changes experienced by the industry. In February 2003 the FERC issued an Order on Remand concluding that for the current five-year period, the oil-pricing index should be the PPI-FG. In order to calculate the 2003 ceiling rate levels, oil pipelines were permitted to use the PPI-FG adjustment as though it had been in effect since 2001. As of July 1, 2007, the index increased to equal PPI-FG plus 1.3 percentage points, resulting in an index of 4.3186% for the period of July 1, 2007 through June 30, 2008.

Regulation by the FERC of Interstate Natural Gas Pipelines

Our AlaTenn, Midla and UTOS systems are interstate natural gas pipelines regulated by the FERC under the Natural Gas Act, or NGA, and the Natural Gas Policy Act, or NGPA. Each system operates under separate FERC-approved tariffs that establish rates, terms and conditions under which each system provides service to its customers. Natural gas companies may not charge rates that have been determined not to be just and reasonable. In addition, the FERC's authority over natural gas companies that provide natural gas pipeline transportation services in interstate commerce includes:

- certification and construction of new facilities;
- extension or abandonment of services and facilities;
- maintenance of accounts and records;
- acquisition and disposition of facilities;
- initiation and discontinuation of services;
- terms and conditions of services and service contracts with customers;
- depreciation and amortization policies;
- conduct and relationship with certain affiliates; and
- various other matters.

The maximum recourse rates that may be charged by our pipelines for their services are established through the FERC's ratemaking process. Generally, the maximum filed recourse rates for interstate pipelines are based on the cost of service including recovery of and a return on the pipeline's actual prudent historical cost investment. Key determinants in the ratemaking process are costs of providing service, allowed rate of return and volume throughput and contractual capacity commitment assumptions. The maximum applicable recourse rates and terms and conditions for service are set forth in each pipeline's FERC approved tariff. Rate design and the allocation of costs also can impact a pipeline's profitability. Our interstate pipelines are permitted to discount their firm and interruptible rates without further FERC authorization down to the variable cost of performing service, provided they do not "unduly discriminate."

Tariff changes can only be implemented upon approval by the FERC. Two primary methods are available for changing the rates, terms and conditions of service of an interstate natural gas pipeline. Under the first method, the pipeline voluntarily seeks a tariff change by making a tariff filing with the FERC justifying the proposed tariff change and providing notice, generally 30 days, to the appropriate parties. If the FERC determines that a proposed change is just and reasonable as required by the NGA, the FERC will accept the proposed change and the pipeline will implement such change in its tariff. However, if the FERC determines that a proposed change may not be just and reasonable as required by the NGA, then the FERC may suspend such change for up to five months beyond the date on which the change would otherwise go into effect and set the matter for an administrative hearing. Subsequent to any suspension period ordered by the FERC, the proposed change may be placed into effect by the company, pending final FERC approval. In most cases, a proposed rate increase is placed into effect before a final FERC determination on such rate increase, and the proposed increase is collected subject to refund (plus interest). Under the second method, the FERC may, on its own motion or based on a complaint, initiate a proceeding seeking to compel the company to change its rates, terms and/or conditions of service. If the FERC determines that the existing rates, terms and/or conditions of service are unjust, unreasonable, unduly discriminatory or preferential, then any rate reduction or change that it orders generally will be effective prospectively from the date of the FERC order requiring this change.

In November 2003, the FERC issued Order 2004 governing the Standards of Conduct for Transmission Providers (including natural gas interstate pipelines). These standards provide that interstate pipeline employees engaged in natural gas transmission system operations must function independently from any employees of their energy affiliates and marketing affiliates and that an interstate pipeline must treat all transmission customers, affiliated and non-affiliated, on a non-discriminatory basis, and cannot operate its transmission system to benefit preferentially, an energy or marketing affiliate. In addition, Order 2004 restricts access to natural gas transmission customer data by marketing and other energy affiliates and provides certain conditions on service provided by interstate pipelines to their gas marketing and energy affiliates. We have implemented changes in business processes to comply with this order. In November 2006, the D.C. Circuit Court vacated Order 2004 as that order applies to interstate natural gas pipelines and remanded that proceeding to the FERC for further action.

On January 9, 2007, the FERC issued Order 690 in response to the D. C. Circuit Court's decision. In its Order, the Commission issued new interim standards of conduct pending the outcome of a new rulemaking proceeding. The interim standards will only govern the relationship between an interstate pipeline and its marketing affiliates as opposed to its energy affiliates, the latter being a much broader category as originally set forth in Order 2004. As a result, the Commission effectively "repromulgated" on a temporary basis the Standards of Conduct first issued in Order 497 in 1992, while it considers its course of action to address the court's decision on a more permanent basis.

On January 18, 2007, the FERC issued a Notice of Proposed Rulemaking ("NOPR") in Docket No. RM07-1 wherein it proposes to make permanent its interim standards of conduct issued in Order 690. The Commission is also seeking comment as to whether it should make comparable changes to the electric industry standards of conduct that were not affected by either the November 2006 decision by the D.C.

Circuit Court, or by Order 690, as well as comments regarding certain other electric-related exceptions to Order 2004. We continue to closely monitor these proceedings and administer our compliance programs accordingly.

On September 20, 2007, the FERC issued a Notice of Inquiry regarding Fuel Retention Practices of Natural Gas Pipelines (Fuel NOI). The Fuel NOI inquires whether the current policy which allows natural gas pipelines to choose between two options for recovering the costs of fuel and lost and unaccounted for (LAUF) gas should be changed in favor of a uniform method. Comments have been filed in response to the Fuel NOI. The outcome of this proceeding could result in changes to the methodology used by our pipelines for calculating fuel and LAUF gas, which could potentially affect the pipelines' revenues.

On September 20, 2007, the FERC issued a Notice of Proposed Rulemaking regarding Revisions to Forms, Statements, and Reporting Requirements for Natural Gas Pipelines (Reporting NOPR). The Reporting NOPR proposed to require pipelines to (i) provide additional information regarding their sources of revenue and amounts included in the rate base; (ii) identify costs related to affiliate transactions; and (iii) provide additional information regarding incremental facilities, and discounted and negotiated rates. According to the FERC, changes would assist pipeline customers and other third parties in analyzing a pipeline's actual return as compared with its approved rate of return based on publicly filed data. Although the FERC proposed that the changes would be effective January 1, 2008, the final rule has not been issued. The FERC's proposed rulemaking is subject to change based on comments filed and therefore we cannot predict the scope of the final rulemaking.

On November 15, 2007, the FERC issued a notice of proposed rulemaking proposing to permit market-based pricing for short-term capacity releases and to facilitate asset management arrangements by relaxing the FERC's prohibition on tying and on its bidding requirements for certain capacity releases (Capacity Release NOPR). The FERC proposes to lift the price ceiling for short-term capacity release transactions of one year or less. The Capacity Release NOPR is proposed to enable releasing shippers to offer competitively-priced alternatives to pipelines' negotiated rates and to encourage more efficient construction of capacity. Under the FERC's proposal, it is possible for the releasing shipper to release the natural gas at market-based prices while our pipelines would still be subject to the maximum rate cap. The FERC's proposed rulemaking is subject to change based on comments filed and therefore we cannot predict the scope of the final rulemaking.

On December 21, 2007, the FERC issued a notice of proposed rulemaking which proposes to require interstate natural gas pipelines and certain non-interstate natural gas pipelines to post capacity, daily scheduled flow information, and daily actual flow information. Comments are due on March 13, 2008, and a technical conference will be held regarding these issues on April 3, 2008. Adoption of this proposal by the FERC could result in additional administrative burdens and could result in increased capital costs.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, the FERC and the courts. The natural gas industry historically has been heavily regulated; therefore, there is no assurance that a more stringent regulatory approach will not be pursued by the FERC and Congress, especially in light of potential market power abuse by marketing affiliates of certain pipeline companies engaged in interstate commerce. In response to this issue, Congress, in the Energy Policy Act of 2005 ("EPACT"), and the FERC have implemented requirements to ensure that energy prices are not impacted by the exercise of market power or manipulative conduct. EPACT prohibits the use of any "manipulative or deceptive device or contrivance" in connection with the purchase or sale of natural gas, electric energy or transportation subject to the FERC's jurisdiction. The FERC then adopted the Market Manipulation Rules and the Market Behavior Rules to implement the authority granted under EPACT. These rules, which prohibit fraud and manipulation in wholesale energy markets, are very vague and are subject to broad interpretation. Only two orders interpreting these rules have been issued to date, and each of these is subject to further proceedings. These orders reflect the FERC's view that it has broad latitude in determining whether specific behavior violates the rules. In addition, EPACT gave the FERC increased penalty authority for these violations. The FERC may now issue civil penalties of up to $1 million per day for each violation of the FERC's rules, and there are possible criminal penalties of up to $1 million and 5 years in prison. Given the FERC's broad mandate granted in EPACT, it is assumed that if energy prices are high, or exhibit what the FERC deems to be "unusual" trading patterns, the FERC will investigate energy markets to determine if behavior unduly impacted or "manipulated" energy prices.

Intrastate Pipeline Regulation

Our intrastate liquids and natural gas pipeline operations generally are not subject to rate regulation by the FERC, but they are subject to regulation by various agencies of the states in which they are located. However, to the extent that our intrastate pipeline systems deliver natural gas into interstate commerce, the rates, terms and conditions of such transportation service are subject to the FERC's jurisdiction under Section 311 of the NGPA, which regulates, among other things, the provision of transportation services by an intrastate natural gas pipeline making deliveries on behalf of a local distribution company or an interstate natural gas pipeline. Most states have agencies that possess the authority to review and authorize natural gas transportation transactions and the construction, acquisition, abandonment and interconnection of physical facilities. Some states also have state agencies that regulate transportation rates, service terms and conditions and contract pricing to ensure their reasonableness and to ensure that the intrastate pipeline companies that they regulate do not discriminate among similarly situated customers.

Natural Gas Gathering Pipeline Regulation

Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of the FERC under the NGA. We own certain natural gas pipelines that we believe meet the traditional tests the FERC has used to establish a pipeline's status as a gatherer not subject to FERC jurisdiction. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements, but historically has not entailed rate regulation. In 2005, the FERC initiated an inquiry regarding the extent to which gathering (both offshore and onshore) systems, particularly those that have been previously transferred from a regulated entity should be regulated by the FERC. The FERC terminated this inquiry in early 2007 without making any finding that would expand its existing regulatory purview over gathering facilities. Further, some states have, or are considering, providing greater regulatory scrutiny over the commercial regulation of natural gas gathering business. Many of the producing states have previously adopted some form of complaint-based regulation that generally allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to natural gas gathering access and rate discrimination. Our gathering operations could be adversely affected should they be subject in the future to the application of state or federal regulation of rates and services. Our gathering operations also may be or become subject to safety and operational regulations relating to the design, installation, testing, construction, operation, replacement and management of gathering facilities.

Sales of Natural Gas, Crude Oil, Condensate and Natural Gas Liquids

The price at which we sell natural gas currently is not subject to federal or state regulation except for certain systems in Texas. Our sales of natural gas are affected by the availability, terms and cost of pipeline transportation. As noted above, the price and terms of access to pipeline transportation are subject to extensive federal and state regulation. The FERC is continually proposing and implementing new rules and regulations affecting those segments of the natural gas industry, most notably interstate natural gas transmission companies that remain subject to the FERC's jurisdiction. These initiatives also may affect the intrastate transportation of natural gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry.

Our sales of crude oil, condensate and natural gas liquids currently are not regulated and are made at market prices. In a number of instances, however, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to the FERC's jurisdiction under the ICA. Certain regulations implemented by the FERC in recent years could increase the cost of transportation service on certain petroleum products pipelines. However, we do not believe that these regulations affect us any differently than other marketers of these products.

Other Regulation

The governments of the United States and Canada have, by treaty, agreed to ensure nondiscriminatory treatment for the passage of oil and natural gas through the pipelines of one country across the territory of the other. Individual border crossing points require U.S. government permits that may be terminated or amended at the will of the U.S. Government. These permits provide that pipelines may be inspected by or subject to orders issued by federal or state government agencies.

Tariffs and Rate Cases

Lakehead system

Under published tariffs at December 31, 2007 (including the tariff surcharges related to Lakehead system expansions) for transportation on the Lakehead system, the rates for transportation of heavy crude oil from Neche, North Dakota, where the System enters the United States (unless otherwise stated), to principal delivery points are set forth below.

	Published Tariff Per Barrel	
To Clearbrook, Minnesota	$	0.2279
To Superior, Wisconsin		0.4562
To Chicago, Illinois area		0.9585
To Marysville, Michigan area		1.1496
To Buffalo, New York area		1.1769
Chicago to the international border near Marysville		0.4118

The rates at December 31, 2007 for light and medium crude oils and NGLs are lower than the rates set forth in the table to compensate for differences in the costs of shipping different types and grades of liquid hydrocarbons. We periodically adjust our tariff rates as allowed under the FERC's indexing methodology and the tariff agreements described below.

Base Rates:

The base portion of the rates for the Lakehead system are subject to an annual escalation, which cannot exceed established ceiling rates as approved by the FERC, and determined in compliance with the FERC-approved indexing methodology.

SEP II Surcharge:

Under the Settlement Agreement with CAPP that the FERC approved in 1996 and reconfirmed in 1998, we implemented a tariff surcharge related to our SEP II project. This tariff surcharge, which is added to the base rates, is a cost-of-service based calculation that is trued-up annually (usually in April) for actual costs and throughputs from the previous calendar year, and is not subject to indexing. The initial term of the SEP II portion of the settlement agreement was for 15 years beginning in 1999.

Terrace Surcharge:

Under the Tariff Agreement approved by the FERC in 1998, we also implemented a tariff surcharge for the Terrace expansion program of approximately \$0.013 per barrel for light crude oil from the Canadian border to Chicago. On April 1, 2001, pursuant to an agreement between us and Enbridge Pipelines Inc. our share of the surcharge was increased to \$0.026 per barrel. This surcharge was in effect until April 1, 2004, when our share of the surcharge changed to \$0.007 per barrel. Our share will remain at this level until 2010, after which time the surcharge will return to \$0.013 per barrel through 2013, the term of the agreement. In addition to the Terrace surcharge, included in our tariff is the Terrace Schedule C adjustment. Under the tariff agreement, when Terrace Phase III facilities are in service, and annual actual average pumping exiting Clearbrook are less than 225,000 M^3 per day, an adjustment is made to the Terrace surcharge. In 2007, this adjustment is \$0.061 per barrel, based on annual actual average pumpings exiting Clearbrook of 197,861 M^3 per day in 2006.

Facilities Surcharge:

On July 1, 2004, the FERC approved a settlement with CAPP involving a Facilities Surcharge mechanism, which allows for the recovery of costs for enhancements or modifications to the system at shipper request and approved by CAPP. The Facilities Surcharge permits the Lakehead system to recover the costs associated with particular shipper-requested projects through an incremental surcharge layered on top of the existing base rates and other FERC-approved surcharges already in effect. Like the SEP II surcharge, the Facilities Surcharge is a cost-of-service-based tariff mechanism that is trued-up each year for actual costs and throughput and, therefore, is not subject to adjustment either upwards or downwards under indexing. In 2007, the Facilities Surcharge was \$0.012 per barrel for light movements from the international border near Neche, North Dakota to Chicago. The Facilities Surcharge currently includes four projects that were agreed to with CAPP in 2004. Additional projects to be included in the Facilities Surcharge will be determined as the result of a negotiating process between management of the Lakehead system and CAPP.

On March 16, 2006, the FERC approved the Offer of Settlement we filed on December 21, 2005, seeking approval for the Southern Access mainline expansion surcharge under the provisions of the previously approved Facilities Surcharge mechanism. The Southern Access mainline expansion centers on the construction of a new 42-inch diameter pipeline between Superior, Wisconsin and Flanagan, Illinois, along with associated upstream modifications to balance the expanded capacity created by the new Superior-to-Flanagan line.

On September 1, 2006, Enbridge filed an Offer of Settlement with the FERC seeking prompt approval for the Southern Access Extension surcharge. The proposed Extension is a new 36-inch pipeline which connects with the Southern Access Mainline Expansion pipeline at Flanagan to Patoka, Illinois, which allows Canadian producers and shippers to access the Patoka hub, where they can then access other refining centers. Under the framework that established the Facilities Surcharge already approved by the Commission, the proposed tolling methodology in the Offer of Settlement asked that the costs for the Extension be added to the existing base rates as a surcharge. A variety of benefits would accrue to shippers through the Extension, including a reduction in total tariff rates due to the higher utilization of upstream facilities and therefore reducing the net cost to shippers even if they do not ship on the Extension itself. The Offer of Settlement was opposed by three shippers and was rejected by the Commission on December 8, 2006, which stated that Enbridge did not submit adequate proof that the proposed pipeline would benefit all shippers.

On October 18, 2007, Enbridge filed a Petition for Declaratory Order with the FERC seeking approval for a revised tariff structure on the Extension and associated surcharges and surcredits on the Lakehead system. The proposed tariff methodology in this petition is a stand alone cost-of-service rate from Flanagan to Patoka, Illinois. However, in the first few years of operation, it is not clear that the pipeline will be able to attract sufficient volumes to recover all of its costs. Thus, a backstopping mechanism with the Lakehead system has been proposed for the pipeline system. In the event that a deficiency occurs for a given year, this deficiency would be recovered from Lakehead mainline shippers. Any surpluses would then be credited back to Lakehead shippers in the form of rate credits until the cumulative deficiency, including interest is eliminated. The term of the agreement is for fifteen years. Enbridge/Lakehead mainline shippers will enjoy various benefits as a result of the expansion. Several parties have filed letters of support of the Declaratory Order, and the Petition has been opposed by one shipper. Enbridge has requested a decision from the FERC by February 2008.

Mid-Continent system

The Mid-Continent system is comprised of pipeline, terminaling, and storage infrastructure located in the U.S. Mid-continent region. Specifically the system originates in Cushing, Payne County, Oklahoma and offers transportation service to Wood River, Madison County, Illinois; West Tulsa, Oklahoma, other Mid-Continent system facilities, local area refineries, and other interconnected non-affiliated pipeline infrastructure. The rates for the transportation of light crude oil from Cushing, Payne County, Oklahoma to principle delivery points are set forth below:

	Published Tariff Per Barrel
To Wood River, Illinois	$ 0.4587
To West Tulsa, Oklahoma	$ 0.1926

The rates at December 31, 2007, outlined above, apply to light crude only. Medium and heavy crude oil transportation rates on these systems are higher to compensate us for differences in the costs of shipping different types and grades of liquid hydrocarbons. In addition to the routes above, we also have the following two joint tariffs—one with All American Pipeline, L.P., which allows for transportation from points in Texas and Jal, New Mexico, to Wood River, Illinois, and another with Koch Pipeline Company, L.P., which allows for transportation from Cushing, Oklahoma, to Hartford Tankage, Illinois.

Where applicable, we periodically adjust our tariff rates as allowed under the FERC's indexing methodology. Currently, this methodology allows for an adjustment of rates equal to the PPI-FG + 1.3%, which adjustment is made effective July 1 of each year.

North Dakota system

Our North Dakota system consists of both gathering and trunk line assets. All gathering rates in effect at December 31, 2007, from points in North Dakota and Montana are $0.6350 per barrel. Effective January 1, 2008, two new surcharges were implemented as a part of the Phase V expansion. In August 2006, we submitted an Offer of Settlement to the FERC for an expansion of the pipeline system, which was approved by the Commission on October 31, 2006 (Docket No. OR06-9-000). The Offer of Settlement outlined the mainline expansion and looping surcharges as cost-of-service based surcharges that will be trued up each year to actual costs and are not subject to the FERC indexing methodology. These surcharges are applicable for the five years immediately following the in-service date of the Phase V expansion, which we placed in service in January 2008. The mainline expansion surcharge is applied to all transportation routes with a destination of Clearbrook, Minnesota, beginning January 1, 2008. The looping surcharge is applied to all routes originating at Trenton and Alexander, North Dakota. The rates and surcharges for transportation of light crude oil to principle delivery points via trunk lines on our North Dakota System are set forth below:

	Published[(1)] Tariff Per Barrel at December 31, 2007	Surcharge[(2)] Per Barrel	Revised Tariff Per Barrel effective January 1, 2008
From Glenburn, Haas, Lignite, Minot, Newburg, Sherwood, Stanley and Wiley, North Dakota to Clearbrook, Minnesota	$ 0.7721	$ 0.1434	$ 0.9155
From Brush Lake and Dwyer, Montana and Grenora, North Dakota to Clearbrook, Minnesota	$ 0.8841	$ 0.1434	$ 1.0275
From Clear Lake, Dagmar, Flat Lake and Reserve, Montana to Clearbrook, Minnesota	$ 0.9089	$ 0.1434	$ 1.0523
From Tioga, North Dakota to Clearbrook, Minnesota	$ 0.7967	$ 0.1434	$ 0.9401
From Trenton and Missouri Ridge, North Dakota to Clearbrook, Minnesota to Clearbrook, Minnesota	$ 1.0088	$ 0.6170	$ 1.6258
From Alexander, North Dakota to Clearbrook, Minnesota	$ 1.0460	$ 0.6170	$ 1.6630
From Brush Lake, Dagmar and Clear Lake, Montana to Tioga, North Dakota	$ 0.4857	—	$ 0.4857
From Reserve, Montana to Tioga, North Dakota	$ 0.5479	—	$ 0.5479
From Trenton and Missouri Ridge, North Dakota to Tioga, North Dakota	$ 0.4609	$ 0.4736	$ 0.9345
From Alexander, North Dakota to Clearbrook, Minnesota	$ 0.4978	$ 0.4736	$ 0.9714

(1) Pursuant to FERC Tariff No. 48 as filed with the FERC on May 30, 2007, with an effective date of July 1, 2007.

(2) Pursuant to FERC Tariff No. 53 as filed with the FERC on November 30, 2007, with an effective date of January 1, 2008.

The rates outlined above, are subject to adjustment as allowed under the indexing methodology established by the FERC. Currently this methodology allows for an adjustment of rates equal to the PPI-FG +1.3%, which is made effective July 1 of each year. In addition to the routes above, we have a joint tariff with Plains Pipeline, L.P., which allows for transportation from points in Richland and McCone counties in Montana to Tioga, North Dakota and Clearbrook, Minnesota.

Natural Gas Systems

Tariff rates on the FERC-regulated natural gas pipelines are approved by the FERC and vary by pipeline depending on a number of factors, including cost of providing service, throughput levels on the pipeline, and other factors. Competitive forces may prompt us to charge tariff rates below the FERC-approved maximum rate on our interstate systems. The rates charged for transmission of natural gas on pipelines not regulated by the FERC, or a state agency, are established by competitive forces.

Safety Regulation and Environmental

General

Our transmission and gathering pipelines and storage and processing facilities are subject to extensive federal and state environmental, operational and safety regulation. The added costs imposed by regulations are generally no different than those imposed on our competitors. The failure to comply with such rules and regulations can result in substantial penalties and/or enforcement actions and added operational costs.

Pipeline Safety and Transportation Regulation

Our transmission and non-rural gathering pipelines are subject to regulation by the United States Department of Transportation, or DOT, Pipeline and Hazardous Materials Safety Administration ("PHMSA") under Title 49 United States Code (Pipeline Safety Act, or PSA) relating to the design, installation, testing, construction, operation, replacement and management of transmission and non-rural gathering pipeline facilities. The PHMSA is the agency charged with regulating the safe transportation of hazardous materials under all modes of transportation, including intrastate pipelines. Periodically the PSA has been reauthorized and amended, imposing new mandates on the regulator to promulgate new regulations, imposing direct mandates on operators of pipelines.

On December 17, 2002, the PSI Act of 2002 was enacted reauthorizing and amending the PSA. The most significant amendment required natural gas pipelines to develop integrity management programs and conduct integrity assessment tests at a minimum of seven year intervals. Such tests can include internal inspection, hydrostatic pressure tests or direct assessments on pipelines in certain high consequence areas. The PHMSA has since promulgated rules for this and other mandates included in the PSI Act of 2002.

On December 29, 2006, the Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006 (PIPES of 2006) was signed into legislation that further amended the Pipeline Safety Act. Many of the provisions were welcome, including strengthening excavation damage prevention and enforcement. The most significant provisions of PIPES of 2006 that will affect us, but not materially, include a mandate to PHMSA to remove most exemptions from federal regulations for liquid pipelines operating at low stress and mandates PHMSA to undertake rulemaking requiring pipeline operators to have a human factors management plan for pipeline control room personnel, including consideration for controlling hours of service.

We have incorporated the new requirements of the 2002 and 2006 PSA amendments into procedures and budgets and, while we expect to incur higher regulatory compliance costs, the increase is not expected to be material.

The Pipeline Safety Act Reauthorization of 2006 (PIPES Act) required, among other measures, for PHMSA to extend their current jurisdictional authority to regulate previously exempted low operating stress pipelines. In September 2007, the PHMSA issued a Notice of Proposed Rulemaking that details how such low stress pipelines would be regulated and the safety measures that would be required. Industry commented and PHMSA is expected to issue the Final Rule early in 2008. The Final Rule is expected to have regulatory requirements that will not materially affect our low stress transmission pipelines.

When hydrocarbons are released into the environment, the PHMSA can impose a return-to-service plan, which can include implementing certain internal inspections, pipeline pressure reductions, and other strategies to verify the integrity of the pipeline in the affected area. We do not anticipate any return-to-service plans that will have a material impact on system throughput or compliance costs; however we have the potential of incurring expenditures to remediate any condition in the event of a discharge or failure on our systems.

Our trucking and railcar operations are also subject to safety and permitting regulation by the DOT and state agencies with regard to the safe transportation of hazardous and other materials.

We believe that our pipeline, trucking and railcar operations are in substantial compliance with applicable operational and safety requirements. In instances of non-compliance, we have taken actions to remediate the situations. Nevertheless, significant expenses could be incurred in the future if additional safety measures are required or if safety standards are raised and exceed the capabilities of our current pipeline control system or other safety equipment.

Environmental Regulation

General. Our operations are subject to complex federal, state, and local laws and regulations relating to the protection of health and the environment, including laws and regulations which govern the handling, storage and release of crude oil and other liquid hydrocarbon materials or emissions from natural gas compression facilities. As with the pipeline and processing industry in general, complying with current and anticipated environmental laws and regulations increases our overall cost of doing business, including our capital costs to construct, maintain, and upgrade equipment and facilities. While these laws and regulations affect our maintenance capital expenditures and net income, we believe that they do not affect our competitive position since the operations of our competitors are generally similarly affected.

In addition to compliance costs, violations of environmental laws or regulations can result in the imposition of significant administrative, civil and criminal fines and penalties and, in some instances, injunctions banning or delaying certain activities. We believe that our operations are in substantial compliance with applicable environmental laws and regulations.

There are also risks of accidental releases into the environment associated with our operations, such as leaks or spills of crude oil, liquids or natural gas or other substances from our pipelines or storage facilities. Such accidental releases could, to the extent not insured, subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury and property damage, and fines, penalties, or damages for related violations of environmental laws or regulations.

Although we are entitled, in certain circumstances, to indemnification from third parties for environmental liabilities relating to assets we acquired from those parties, these contractual indemnification rights are limited and, accordingly, we may be required to bear substantial environmental expenses. However, we believe that through our due diligence process, we identify and manage substantial issues.

Air and Water Emissions. Our operations are subject to the federal Clean Air Act, or CAA, and the federal Clean Water Act, or CWA, and comparable state and local statutes. We anticipate, therefore, that we will incur certain capital expenses in the next several years for air pollution control equipment and spill prevention measures in connection with maintaining existing facilities and obtaining permits and approvals for any new or acquired facilities.

The Oil Pollution Act (OPA) was enacted in 1990 and amends parts of the CWA and other statutes as they pertain to the prevention of and response to oil spills. Under the OPA, we could be subject to strict, joint and potentially unlimited liability for removal costs and other consequences of an oil spill from our facilities into navigable waters, along shorelines or in an exclusive economic zone of the United States. The OPA also imposes certain spill prevention, control and countermeasure requirements for many of our non-pipeline facilities, such as the preparation of detailed oil spill emergency response plans and the construction of dikes or other containment structures to prevent contamination of navigable or other waters in the event of an oil overflow, rupture or leak. For our liquid pipeline facilities, the OPA imposes requirements for emergency plans to be prepared, submitted and approved by the DOT. For our non-transportation facilities, such as storage tanks that are not integral to pipeline transportation system, the OPA regulations are promulgated by the Environmental Protection Agency, or EPA. We believe we are in material compliance with these laws and regulations.

Hazardous Substances and Waste Management. The federal Comprehensive Environmental Response, Compensation, and Liability Act, or CERCLA (also known as the "Superfund" law), and similar state laws, impose liability without regard to fault or the legality of the original conduct, on certain classes of persons, including the owners or operators of waste disposal sites and companies that disposed or arranged for disposal of hazardous substances found at such sites. We may generate some wastes that fall within the definition of a "hazardous substance." We may, therefore, be jointly and severally liable under CERCLA for all or part of any costs required to clean up and restore sites at which such wastes have been disposed. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. Analogous state laws may apply to a broader range of substances than CERCLA and, in some instances, may offer fewer exemptions from liability. We have not received any notification that we may be potentially responsible for material cleanup costs under CERCLA or similar state laws.

Employee Health and Safety. The workplaces associated with our operations are subject to the requirements of the federal Occupational Safety and Health Administration, or OSHA, and comparable state statutes that regulate worker health and safety. We have an ongoing safety, procedure and training program for our employees and believe that our operations are in compliance with applicable OSHA requirements, including industry consensus standards, record keeping requirements, monitoring of occupational exposure to regulated substances, and hazard communication standards.

Site Remediation. We own and operate a number of pipelines, gathering systems, storage facilities and processing facilities that have been used to transport, distribute, store and process crude oil, natural gas and other petroleum products. Many of our facilities were previously owned and operated by third parties whose handling, disposal and release of petroleum and waste materials were not under our control. The age of the facilities, combined with the past operating and waste disposal practices, which were standard for the industry and regulatory regime at the time, have resulted in soil and groundwater contamination at some facilities due to historical spills and releases. Such contamination is not unusual within the natural gas and petroleum industry. Historical contamination found on, under or originating from our properties may be subject to CERCLA, Resource Conservation & Recovery Act and analogous state laws as described above.

Under these laws, we could incur substantial expense to remediate such contamination, including contamination caused by prior owners and operators. In addition, Enbridge Management, as the entity with managerial responsibility for us, could also be liable for such costs to the extent that we are unable to fulfill our obligations. We have conducted site investigations at some of our facilities to assess historical environmental issues, and we are currently addressing soil and groundwater contamination at various facilities through remediation and monitoring programs, with oversight by the applicable government agencies where appropriate.

EMPLOYEES

Neither we nor Enbridge Management, have any employees. Our general partner has delegated to Enbridge Management, pursuant to a delegation of control agreement, substantially all of the responsibility for our day-to-day management and operation. Our general partner, however, retains certain functions and approval rights over our operations. To fulfill its management obligations, Enbridge Management has entered into agreements with Enbridge and several of its affiliates to provide Enbridge Management with the necessary services and support personnel, who act on Enbridge Management's behalf as its agents. We are ultimately responsible for reimbursing these service providers based on the costs that they incur in performing these services.

INSURANCE

Our operations are subject to many hazards inherent in the liquid petroleum and natural gas gathering, treating, processing and transportation industry. We maintain insurance coverage for our operations and properties considered to be customary in the industry. Our coverage limits for property and business interruption, general liability, and pollution liability insurance are expressed in Canadian dollars, or CAD, and range from $400 million CAD to $650 million CAD, representing $404.8 million to $657.8 million in United States dollars (USD) at December 31, 2007 based on the exchange rate of $1.0120 USD = $1 CAD at this date. Insurance policy deductibles are stated in CAD and vary with coverage. As expressed in USD our deductibles are approximately $10.2 million, $0.1 million, and $2.5 million for property, general liability, and pollution liability, respectively, which have been converted from CAD based on the exchange rate presented above. We can make no assurance that the insurance coverage we maintain will be available or adequate for any particular risk or loss, or that we will be able to maintain adequate insurance in the future at rates we consider reasonable. Although we believe that our assets are adequately covered by insurance, a substantial uninsured loss could have a material adverse effect on our financial position, results of operations and cash flows.

TAXATION

We are not a taxable entity for U.S. federal income tax purposes. Generally, federal and state income taxes on our taxable income are borne by our individual partners through the allocation of our taxable income. In a limited number of states, an income tax is imposed upon us and generally, not our individual partners. The income tax that we bear is reflected in our consolidated financial statements. The allocation of taxable income to our individual partners may vary substantially from net income reported in our consolidated statements of income.

AVAILABLE INFORMATION

We file annual, quarterly and other reports, and any amendments to those reports, and information with the Securities and Exchange Commission, or SEC, under the Securities Exchange Act of 1934, as amended, which we refer to as the Exchange Act. You may read and copy any materials that we file with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington, DC 20549. You may obtain additional information about the Public Reference Room by calling the SEC at 1-800-SEC-0330. In addition, the SEC maintains an Internet site *http://www.sec.gov* that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC, including ours.

We also make available free of charge on or through our Internet website *http://www.enbridgepartners.com* our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and other information statements, and if applicable, amendments to those reports filed or furnished pursuant to Section 13(a) of the Exchange Act, as soon as reasonably practicable after we electronically file such material with the SEC. Information contained on our website is not part of this report.

Item 1A. Risk Factors

We encourage you to read the risk factors below in connection with the other sections of this Annual Report on Form 10-K.

RISKS RELATED TO OUR BUSINESS

Our financial performance could be adversely affected if our pipeline systems are used less.

Our financial performance depends to a large extent on the volumes transported on our pipeline systems. Decreases in the volumes transported by our systems can directly and adversely affect our revenues and results of operations. The volume transported on our pipelines can be influenced by factors beyond our control including:

- competition;
- regulatory action;
- weather conditions
- storage levels;
- alternative energy sources;
- decreased demand;
- fluctuations in energy commodity prices;
- economic conditions;
- supply disruptions;
- availability of supply connected to our pipeline systems; and
- availability and adequacy of infrastructure to move supply to our system.

The volume of shipments on our Lakehead system depends heavily on the supplies of western Canadian crude oil. Insufficient supplies of western Canadian crude oil will adversely affect our business by limiting shipments on our Lakehead system. Decreases in conventional crude oil exploration and production activities in western Canada and other factors including supply disruption and competition can reduce the utilization of our Lakehead system. For example, in January 2005, deliveries on our Lakehead system were impacted by a fire at a Suncor facility. The volume of crude oil that we transport on the Lakehead system also depends on the demand for crude oil in the Great Lakes and Midwest regions of the United States and the delivery by others of crude oil and refined products into these regions and the Province of Ontario. Pipeline capacity for the delivery of crude oil to the Great Lakes and Midwest regions of the United States currently exceeds refining capacity.

In addition, our ability to increase deliveries to expand the Lakehead system in the future depends on increased supplies of western Canadian crude oil. We expect that growth in future supplies of western Canadian crude oil will come from oil sands projects in Alberta, Canada. Furthermore, full utilization of additional capacity as a result of our current and future expansions of the Lakehead system, including the Southern Access project, will largely depend on these anticipated increases in crude oil production from oil sands projects. The government of the Province of Alberta has adopted measures to increase its share of revenues from oil sands development. These measures could cause oil sands producers to cancel or delay plans to expand their facilities, which, in turn, would reduce the volume growth we have anticipated in executing our construction projects to increase the capacity of our crude oil pipelines.

The volume of shipments on natural gas systems depends on the supply of natural gas and NGLs available for shipment on those systems from the producing regions that supply these systems. Volumes shipped on these systems also are affected by the demand for natural gas and NGLs in the markets these systems serve. Existing customers may not extend their contracts for a variety of reasons, including a decline in the availability of natural gas from the Mid-continent, Gulf Coast and East Texas producing regions, or if the cost of transporting natural gas from other producing regions through other pipelines into the markets served by the natural gas systems was to render the delivered cost of natural gas on our systems uneconomical. We may be unable to find additional customers to replace the lost demand or transportation fees.

Changes in, or challenges to, our rates could have a material adverse effect on our financial condition and results of operations.

The rates charged by several of our pipeline systems are regulated by the FERC or state regulatory agencies or both. If one of these regulatory agencies, on its own initiative or due to challenges by third parties, were to lower our tariff rates, the profitability of our pipeline businesses might suffer. If we were permitted to raise our tariff rates for a particular pipeline, there might be significant delay between the time the tariff rate increase is approved and the time that the rate increase actually goes into effect, which delay could further reduce our cash flow. Furthermore, competition from other pipeline systems may prevent us from raising our tariff rates even if regulatory agencies permit us to do so. The regulatory agencies that regulate our systems periodically implement new rules, regulations and terms and conditions of services subject to their jurisdiction. New initiatives or orders may adversely affect the rates charged for our services. Some producing states, including Oklahoma and Texas, are considering legislation that would require rate and/or service regulation of gathering and intrastate transmission natural gas systems. Increased state regulation could adversely impact our natural gas systems.

The question of whether and to what extent an income tax allowance should be included in a regulated utility's cost of service for rate-making purposes was a matter of uncertainty for a number of years. On May 29, 2007, the D.C. Circuit Court denied petitions for review of the FERC's income tax allowance ("ITA") policy. The D.C. Circuit Court, which previously vacated and remanded prior FERC orders on the subject, affirmed the ITA policy that the FERC adopted in its May 4, 2005, Policy Statement on Income Tax Allowances, 111 FERC ¶ 61,139 ("Policy Statement"), which concluded that "such an allowance should be permitted on all partnership interests, or similar legal interests, if the owner of that interest has an actual or potential income tax liability on the public utility income earned through the interest," thereby extending the ITA to both corporations and partnerships (or other pass-through entities). In addition, the FERC's Policy Statement contemplates that individual rate proceedings will determine "whether a particular partner... has an actual or potential income tax liability, and what assumptions, if any, should determine the amount of the related tax rate..."

A related issue is whether the FERC's Policy Statement can be relied upon by shippers as a substantial change in circumstances sufficient to remove the grandfathering protection under the EP Act from an oil pipeline's rates. As part of its May 29, 2007 opinion, the D.C. Circuit Court denied the petitions for review with respect to the EP Act issues and upheld the FERC's interpretation of the EP Act as reasonable.

We believe that the rates we charge for transportation services on our interstate common carrier pipelines are just and reasonable under the ICA and NGA. However, because the rates that we charge are subject to review upon an appropriately supported protest or complaint, we cannot predict what rates we will be allowed to charge in the future for service on our interstate common carrier pipelines. Furthermore, because rates charged for transportation services must be competitive with those charged by other transporters, the rates set forth in our tariffs will be determined based on competitive factors in addition to regulatory considerations.

Competition may reduce our revenues.

Our Lakehead system faces current, and potentially further competition for transporting western Canadian crude oil from other pipelines, which may reduce our revenues. Our Lakehead system competes with other crude oil and refined product pipelines and other methods of delivering crude oil and refined products to the refining centers of Minneapolis-St. Paul, Minnesota; Chicago, Illinois; Detroit, Michigan; Toledo, Ohio; Buffalo, New York; and Sarnia, Ontario and the refinery market and pipeline hub located in the Patoka/Wood River area of southern Illinois. Refineries in the markets served by our Lakehead system compete with refineries in western Canada, the Province of Ontario and the Rocky Mountain region of the United States for supplies of western Canadian crude oil.

Our Ozark pipeline system could face a significant increase in competition if a proposed new pipeline from Hardisty, Alberta to Patoka is completed in 2009. However, if that situation occurs, we would consider potential alternative uses for our Ozark system.

We also encounter competition in our natural gas gathering, treating, processing, and transmission businesses. A number of new interstate natural gas transmission pipelines being constructed could reduce the revenue we derive from the interstate and intrastate transmission of natural gas. Many of the large wholesale customers served by our systems' transmission and wholesale customer pipelines have multiple pipelines connected or adjacent to their facilities. Thus, many of these wholesale customers have the ability to purchase natural gas directly from a number of pipelines and/or from third parties that may hold capacity on other pipelines. For example, our Midla system is currently negotiating the renewal of a contract with one of its primary customers that is set to expire in August 2008, and could result in a contract with less favorable terms. Other systems such as our AlaTenn system face similar competition. Likewise, most natural gas producers and owners have alternate gathering and processing facilities available to them. In addition, they have other alternatives, such as building their own gathering facilities or, in some cases, selling their natural gas supplies without processing. Some of our natural gas marketing competitors have greater financial resources and access to larger supplies of natural gas than those available to us, which could allow those competitors to price their services more aggressively than we do.

Our gas marketing operations involve market and certain regulatory risks.

As part of our natural gas marketing activities, we purchase natural gas at prices determined by prevailing market conditions. Following our purchase of natural gas, we generally resell natural gas at a higher price under a sales contract that is generally comparable in terms to our purchase contract, including any price escalation provisions. The profitability of our natural gas operations may be affected by the following factors:

- our ability to negotiate on a timely basis natural gas purchase and sales agreements in changing markets;
- reluctance of wholesale customers to enter into long-term purchase contracts;
- consumers' willingness to use other fuels when natural gas prices increase significantly;
- timing of imbalance or volume discrepancy corrections and their impact on financial results;
- the ability of our customers to make timely payment;
- inability to match purchase and sale of natural gas on comparable terms; and
- changes in, limitations upon, or elimination of the regulatory authorization required for our wholesale sales of natural gas in interstate commerce.

Our results may be adversely affected by commodity price volatility and risks associated with our hedging activities.

We buy and sell natural gas and NGLs in connection with our marketing activities. Commodity price exposure is also inherent in gas purchase and resale activities and in gas processing. To the extent that we engage in hedging activities to reduce our commodity price exposure, we may be prevented from realizing the full benefits of price increases above the level of the hedges. Further, hedging contracts are subject to the credit risk that the other party may prove unable or unwilling to perform its obligations under such contracts. In addition certain of the financial instruments we use to hedge our commodity risk exposures must be accounted for on a mark-to-market basis. This causes periodic earnings volatility due to fluctuations in commodity prices.

Compliance with environmental and operational safety regulations, including any remediation of soil or water pollution or hydrostatic testing of our pipeline systems, may increase our costs and/or reduce our revenues.

Our pipeline, gathering, processing and trucking operations are subject to federal, state and local laws and regulations relating to environmental protection and operational and worker safety. Liquid petroleum and natural gas transportation and processing operations always involve the risk of costs or liabilities or operational modifications related to regulatory compliance as well as resulting from historical environmental contamination, accidental releases or upsets, regulatory enforcement, litigation or safety and health incidents. As a result, we may incur costs or liabilities of this type, or experience a reduction in revenues, in the future. We may also establish temporary pressure restrictions on some sections of our pipelines pending completion of specific inspection and renewal programs. Pressure restrictions reduce the available capacity of the applicable line segment and could result in a loss of throughput and related revenue if and when the full capacity of that line segment would otherwise have been utilized. We may also incur costs in the future due to changes in environmental and safety laws and regulations, enforcement policies or claims for personal, property or environmental damage. We may not be able to recover these costs from insurance or through higher tariffs.

Pipeline operations involve numerous risks that may adversely affect our business and financial condition.

Operation of complex pipeline systems, gathering, treating, processing and trucking operations involves many risks, hazards and uncertainties. These events include adverse weather conditions, accidents, the breakdown or failure of equipment or processes, the performance of the facilities below expected levels of capacity and efficiency and catastrophic events such as explosions, fires, earthquakes, hurricanes, floods, landslides or other similar events beyond our control. A casualty occurrence might result in injury or loss of life or extensive property or environmental damage for which we may bear a part or all of the cost.

Our acquisition strategy may be unsuccessful if we incorrectly predict operating results, are unable to identify and complete future acquisitions and integrate acquired assets or businesses or are unable to raise financing on acceptable terms.

The acquisition of complementary energy delivery assets is a component of our strategy. Acquisitions present various risks and challenges, including:

- the risk of incorrect assumptions regarding the future results of the acquired operations or expected cost reductions or other synergies expected to be realized as a result of acquiring such operations;
- the risk of failing to effectively integrate the operations or management of acquired assets or businesses or a significant delay in such integration; and
- diversion of management's attention from existing operations.

In addition, we may be unable to identify acquisition targets and consummate acquisitions in the future or be unable to raise, on terms we find acceptable, any debt or equity financing that may be required for any such acquisition.

Our actual construction and development costs could exceed our forecast and our cash flow from construction and development projects may not be immediate which may limit our ability to increase cash distributions.

Our strategy contemplates significant expenditures for the development, construction or other acquisitions of energy infrastructure assets. Increased demand for the steel used to fabricate the pipe needed for our construction projects and increased competition for labor has resulted in increased costs for these resources. As a result, we may not be able to complete our projects at the costs currently estimated or within the time periods we have projected. If we experience material cost overruns, we will have to finance these overruns using one or more of the following methods:

- using cash from operations;
- delaying other planned projects;
- incurring additional indebtedness; or
- issuing additional equity.

Any or all of these methods may not be available when needed or may adversely affect our future results of operations and cash flows.

Our revenues and cash flows may not increase immediately on our expenditure of funds on a particular project. For example, if we build a new pipeline or expand an existing facility, the design, construction, development and installation may occur over an extended period of time and we may not receive any material increase in revenue or cash flow from that project until after it is placed in service and customers begin using the systems. If our revenues and cash flow do not increase at projected levels because of substantial unanticipated delays, or other factors, we may not meet our obligations as they become due and we may need to reduce or reprioritize our capital budget, sell non-strategic assets, access the capital markets or reassess our level of distributions to unitholders to meet our capital requirements.

Measurement losses on our pipeline system can be materially impacted by changes in estimation, commodity prices and other factors.

Oil measurement losses occur as part of the normal operating conditions associated with our liquid petroleum pipelines. The three types of oil measurement losses include:

- physical losses, which occur through evaporation, shrinkage, differences in measurement between receipt and delivery locations and other operational incidents;
- degradation losses, which result from mixing at the interface between higher quality light crude oil and lower quality heavy crude oil in pipelines; and
- revaluation losses, which are a function of crude oil prices and the level of the carrier's inventory.

Quantifying oil measurement losses is inherently difficult because physical measurements of volumes are not practical due to the fact that products constantly move through our pipelines and virtually all of our pipeline systems are located underground. In our case, measuring and quantifying oil measurement losses is especially difficult because of the size and scope of our pipeline systems and the number of different grades of crude oil and types of crude oil products we carry. Accordingly, we utilize engineering-based models and operational assumptions to estimate product volumes in our system and associated oil measurement losses.

Natural gas measurement losses occur as part of the normal operating conditions associated with our natural gas pipelines. The quantification and resolution of measurement losses is complicated by several factors including: 1) the significant quantities (i.e., thousands) of measurement meters that we use throughout our natural gas systems, primarily around our gathering and processing assets; 2) varying qualities of natural gas in the streams gathered and processed through our systems; and 3) variances in measurement that are inherent in metering technologies. Each of these factors may contribute to measurement losses that can occur on our natural gas systems.

The interests of Enbridge may differ from our interests and the interests of our security holders, and the board of directors of Enbridge Management may consider the interests of all parties to a conflict, not just the interests of our security holders, in making important business decisions.

Enbridge indirectly owns all of the shares of our general partner and all of the voting shares of Enbridge Management, and elects all of the directors of both companies. Furthermore, some of the directors and officers of our general partners and Enbridge Management are also directors and officers of Enbridge. Consequently, conflicts of interest could arise between our unitholders and Enbridge.

Our partnership agreement limits the fiduciary duties of our general partner to our unitholders. These restrictions allow our general partner to resolve conflicts of interest by considering the interests of all of the parties to the conflict, including Enbridge Management's interests, our interests and those of our general partner. In addition, these limitations reduce the rights of our unitholders under our partnership agreement to sue our general partner or Enbridge Management, its delegee, should its directors or officers act in a way that, were it not for these limitations of liability, would constitute breaches of their fiduciary duties.

We do not have any employees. In managing our business and affairs, we rely on employees of Enbridge, and its affiliates, who act on behalf of and as agents for us. A decrease in the availability of employees from Enbridge could adversely affect us.

We are exposed to credit risks of our customers

Some of our customers may experience financial problems that could have a significant affect on their creditworthiness. Severe financial problems encountered by our customers could limit our ability to collect amounts owed to us, or to enforce performance of obligations under contractual arrangements. For example, in December 2005, Calpine and many of its subsidiaries, including the subsidiary that owns two utility plants served by our Bamagas system, filed voluntarily petitions to restructure under Chapter 11 of the United States Bankruptcy Code. Our Bamagas system is the sole supplier of natural gas to these two utility plants, which exposed us to a potential asset impairment for the book value of the pipeline, if the customer was unable to fulfill its commitments. Financial problems experienced by our customers may also reduce or curtail their future use of our products and services, which could reduce our revenues.

Canada's ratification of the Kyoto Protocol may adversely impact our operations.

In December 2002, Canada ratified the Kyoto Protocol, a 1997 treaty designed to reduce greenhouse gas emissions to 6% below 1990 levels. We and Enbridge are monitoring the Canadian federal government's approach to implementation. While the United States is not a signatory to the Kyoto Protocol, other environmental protection initiatives have been implemented regulating certain priority pollutants. Revisions have been proposed to the U.S. Energy Act that would, if passed, expand the regulation of certain greenhouse gas emissions requiring a cap and establishing a trade to facilitate compliance. While proposed legislation has not yet passed and as other legislation is being proposed the outcome is uncertain at this time. If and when these provisions pass the Partnership could be subject to additional costs to monitor and control emissions above and beyond current practices and permits.

RISKS ARISING FROM OUR PARTNERSHIP STRUCTURE AND RELATIONSHIPS WITH OUR GENERAL PARTNER AND ENBRIDGE MANAGEMENT

Our partnership agreement and the delegation of control agreement limit the fiduciary duties that Enbridge Management and our general partner owe to our unitholders and restrict the remedies available to our unitholders for actions taken by Enbridge Management and our general partner that might otherwise constitute a breach of a fiduciary duty.

Our partnership agreement contains provisions that modify the fiduciary duties that our general partner would otherwise owe to our unitholders under state fiduciary duty law. Through the delegation of control agreement, these modified fiduciary duties also apply to Enbridge Management as the delegate of our general partner. For example, our partnership agreement:

- permits our general partner to make a number of decisions, including the determination of which factors it will consider in resolving conflicts of interest, in its "sole discretion." This entitles our general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give consideration to any interest of, or factors affecting, us, our affiliates or any unitholder;

- provides that any standard of care and duty imposed on our general partner will be modified, waived or limited as required to permit our general partner to act under our partnership agreement and to make any decision pursuant to the authority prescribed in our partnership agreement, so long as such action is reasonably believed by the general partner to be in our best interests; and

- provides that our general partner and its directors and officers will not be liable for monetary damages to us or our unitholders for any acts or omissions if they acted in good faith.

These and similar provisions in our partnership agreement may restrict the remedies available to our unitholders for actions taken by Enbridge Management or our general partner that might otherwise constitute a breach of a fiduciary duty.

Potential conflicts of interest may arise among Enbridge and its shareholders, on the one hand, and us and our unitholders and Enbridge Management and its shareholders, on the other hand. Because the fiduciary duties of the directors of our general partner and Enbridge Management have been modified, the directors may be permitted to make decisions that benefit Enbridge and its shareholders or Enbridge Management and its shareholders more than us and our unitholders.

Conflicts of interest may arise from time to time among Enbridge and its shareholders, on the one hand, and us and our unitholders and Enbridge Management and its shareholders, on the other hand. Conflicts of interest may also arise from time to time between us and our unitholders, on the one hand, and Enbridge Management and its shareholders, on the other hand. In managing and controlling us as the delegate of our general partner, Enbridge Management may consider the interests of all parties to a conflict and may resolve those conflicts by making decisions that benefit Enbridge and its shareholders or Enbridge Management and its shareholders more than us and our unitholders. The following decisions, among others, could involve conflicts of interest:

- whether we or Enbridge will pursue certain acquisitions or other business opportunities;

- whether we will issue additional units or other equity securities or whether we will purchase outstanding units;

- whether Enbridge Management will issue additional shares;

- the amount of payments to Enbridge and its affiliates for any services rendered for our benefit;

- the amount of costs that are reimbursable to Enbridge Management or Enbridge and its affiliates by us;
- the enforcement of obligations owed to us by Enbridge Management, our general partner or Enbridge, including obligations regarding competition between Enbridge and us; and
- the retention of separate counsel, accountants or others to perform services for us and Enbridge Management.

In these and similar situations, any decision by Enbridge Management may benefit one group more than another, and in making such decisions, Enbridge Management may consider the interests of all groups, as well as other factors, in deciding whether to take a particular course of action.

In other situations, Enbridge may take certain actions, including engaging in businesses that compete with us, that are adverse to us and our unitholders. For example, although Enbridge and its subsidiaries are generally restricted from engaging in any business that is in direct material competition with our businesses, that restriction is subject to the following significant exceptions:

- Enbridge and its subsidiaries are not restricted from continuing to engage in businesses, including the normal development of such businesses, in which they were engaged at the time of our initial public offering in December 1991;
- such restriction is limited geographically only to those routes and products for which we provided transportation at the time of our initial public offering;
- Enbridge and its subsidiaries are not prohibited from acquiring any business that materially and directly competes with us as part of a larger acquisition, so long as the majority of the value of the business or assets acquired, in Enbridge's reasonable judgment, is not attributable to the competitive business; and
- Enbridge and its subsidiaries are not prohibited from acquiring any business that materially and directly competes with us if that business is first offered for acquisition to us and the board of directors of Enbridge Management and our unitholders determine not to pursue the acquisition.

Since we were not engaged in any aspect of the natural gas business at the time of our initial public offering, Enbridge and its subsidiaries are not restricted from competing with us in any aspect of the natural gas business. In addition, Enbridge and its subsidiaries would be permitted to transport crude oil and liquid petroleum over routes that are not the same as our Lakehead system, even if such transportation is in direct material competition with our business.

These exceptions also expressly permitted the reversal by Enbridge in 1999 of one of its pipelines that extends from Sarnia, Ontario to Montreal, Quebec. As a result of this reversal, Enbridge competes with us to supply crude oil to the Ontario, Canada market.

We can issue additional common or other classes of units, including additional i-units to Enbridge Management when it issues additional shares, which would dilute your ownership interest.

The issuance of additional common or other classes of units by us, including the issuance of additional i-units to Enbridge Management when it issues additional shares and the issuance of additional Class C units, other than our quarterly distributions to you, may have the following effects:

- the amount available for distributions on each unit may decrease;
- the relative voting power of each previously outstanding unit may decrease; and
- the market price of the Class A common units may decline.

Additionally, the public sale by our general partner of a significant portion of the Class B common units or Class C units that it currently owns could reduce the market price of the Class A common units. Our partnership agreement allows the general partner to cause us to register for public sale any units held by the general partner or its affiliates. A public or private sale of the Class B common units or Class C units currently held by our general partner could absorb some of the trading market demand for the outstanding Class A common units.

We are a holding company and depend entirely on our operating subsidiaries' distributions to service our debt obligations.

We are a holding company with no material operations. If we cannot receive cash distributions from our operating subsidiaries, we will not be able to meet our debt service obligations. Our operating subsidiaries may from time to time incur additional indebtedness under agreements that contain restrictions, which could further limit each operating subsidiary's ability to make distributions to us.

The debt securities we issue and any guarantees issued by the Subsidiary Guarantors will be structurally subordinated to the claims of the creditors of any of our operating subsidiaries who are not guarantors of the debt securities. Holders of the debt securities will not be creditors of our operating subsidiaries who have not guaranteed the debt securities. The claims to the assets of these non-guarantor operating subsidiaries derive from our own ownership interest in those operating subsidiaries. Claims of our non-guarantor operating subsidiaries' creditors will generally have priority as to the assets of such operating subsidiaries over our own ownership interest claims and will therefore have priority over the holders of our debt, including the debt securities. Our non-guarantor operating subsidiaries' creditors may include:

- general creditors;
- trade creditors;
- secured creditors;
- taxing authorities; and
- creditors holding guarantees.

Enbridge Management's discretion in establishing our cash reserves gives it the ability to reduce the amount of cash available for distribution to our unitholders.

Enbridge Management may establish cash reserves for us that in its reasonable discretion are necessary to fund our future operating and capital expenditures, provide for the proper conduct of business, and comply with applicable law or agreements to which we are a party or to provide funds for future distributions to partners. These cash reserves affect the amount of cash available for distribution to our holders of common units.

RISKS RELATED TO OUR DEBT AND OUR ABILITY TO MAKE DISTRIBUTIONS

Agreements relating to our debt restrict our ability to make distributions, which could adversely affect the value of our Class A Common Units, and our ability to incur additional debt and otherwise maintain financial and operating flexibility.

Our primary operating subsidiary is prohibited by its First Mortgage Notes from making distributions to us, and we are prohibited from making distributions to us other than cash distributions, and it may make cash distributions to us only if (1) the distribution amount does not exceed the current available cash of that subsidiary, (2) a default does not exist under the First Mortgage Notes after giving effect to the distribution and (3) timely notice of the distribution has been give to the Note holders. In addition, we are prohibited from making distributions to our unitholders during (1) the existence of certain defaults under our Credit Facility or (2) during a period in which we have elected to defer interest payments on the Junior Notes, subject to limited exceptions as set forth in the related indenture. Further, the agreements governing our Credit Facility and our subsidiary's First Mortgage Notes may prevent us from engaging in transactions or capitalizing on business opportunities that we believe could be beneficial to us by requiring us to comply with various covenants, including the maintenance of certain financial ratios and restrictions on:

- incurring additional debt;
- entering into mergers or consolidations or sales of assets; and
- granting liens.

Although the indentures governing our senior notes do not limit our ability to incur additional debt, they impose restrictions on our ability to enter into mergers or consolidations and sales of all or substantially all of our assets, to incur liens to secure debt and to enter into sale and leaseback transactions. A breach of any restriction under our credit facility or our indentures or our subsidiary's First Mortgage Notes could permit the holders of the related debt to declare all amounts outstanding under those agreements immediately due and payable and, in the case of our Credit Facility, terminate all commitments to extend further credit. Any subsequent refinancing of our current debt or any new indebtedness incurred by us or our subsidiaries could have similar or greater restrictions.

TAX RISKS TO COMMON UNITHOLDERS

We may be classified as an association taxable as a corporation rather than as a partnership, which would substantially reduce the value of our Class A common units.

We could be treated as a corporation for United States income tax purposes. Our treatment as a corporation would substantially reduce the cash distributions on the common units that we distribute quarterly. Moreover, treatment of us as a corporation could materially and adversely affect our ability to make payments on our debt securities. The anticipated benefit of an investment in our common units depends largely on the treatment of us as a partnership for federal income tax purposes. Under current law, we are treated as a partnership for federal income tax purposes and do not pay any federal income tax at the entity level. In order to qualify for this treatment, we must derive more than 90% of our annual gross income from specified investments and activities. While we believe that we currently do qualify and intend to meet this income requirement, we may not find it possible, regardless of our efforts, to meet this income requirement or may inadvertently fail to meet this income requirement. Current law may change so as to cause us to be treated as a corporation for federal income tax purposes without regard to our sources of income or otherwise subject us to entity-level taxation. If we were to be treated as a corporation for federal income tax purposes, we would pay federal income tax on our income at the corporate tax rate, which is currently a maximum of 35% and would pay state income taxes at varying rates. Under current law, distributions to unitholders would generally be taxed as a corporate distribution. Because a tax would be imposed upon us as a corporation, the cash available for distribution to a unitholder would be substantially reduced. Treatment of us as a corporation would cause a substantial reduction in the value of our units.

In addition, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise, or other forms of taxation similar to recent tax legislation in Texas and Michigan. State tax legislation resulting in the imposition of a partnership-level income tax on us could reduce the cash distributions we make on the Class A and B common units and the number of i-units and Class C units that we will distribute quarterly. The enactment of significant legislation imposing partnership-level income taxes could cause a reduction in the value of our Class A common units.

If the Internal Revenue Service does not respect our curative tax allocations, the after-tax return to our unitholders on their investment in our Class A common units would be adversely affected.

Our partnership agreement allows curative allocations of income, deduction, gain and loss by us to account for differences between the tax basis and fair market value of property at the time the property is contributed or deemed contributed to us and to account for differences between the fair market value and book basis of our assets existing at the time of issuance of any Class A common units. If the Internal Revenue Service, which we refer to as the IRS, does not respect our curative allocations, ratios of taxable income to cash distributions received by the holders of Class A common units will be materially higher than previously estimated

The tax liability of our unitholders could exceed their distributions or proceeds from sales of Class A common units.

The holders of our Class A common units will be required to pay United States federal income tax and, in some cases, state and local income taxes on their allocable share of our income, even if they do not receive cash distributions from us. They will not necessarily receive cash distributions equal to the tax on their allocable share of our taxable income. Further, if we have a large amount of nonrecourse liabilities, they may incur a tax liability that is greater than the money they receive when they sell their Class A common units.

A unitholder may be required to file tax returns with and pay income taxes to the states where we or our subsidiaries own property and conduct business.

In some cases, a unitholder may be required to file income tax returns with and pay income taxes to the states in which we or our subsidiaries own property and conduct business, which are currently Alabama, Arkansas, Florida, Georgia, Illinois, Indiana, Kansas, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, New York, South Carolina, North Carolina, North Dakota, Oklahoma, Tennessee, Texas and Wisconsin. In the future, we may acquire property or do business in other states or in foreign jurisdictions. In addition to tax liabilities to such state and foreign jurisdictions, the owner of a Class A common unit may also incur tax and filing responsibilities to localities within such jurisdictions.

Ownership of Class A common units raises issues for tax-exempt entities and other investors.

An investment in our Class A common units by tax-exempt entities, including employee benefit plans, individual retirement accounts, Keogh plans and other retirement plans, regulated investment companies and foreign persons raises issues unique to them. Virtually all of the income derived from our Class A common units by a tax-exempt entity will be "unrelated business taxable income" and will be taxable to the tax-exempt entity. Further, a unitholder who is a nonresident alien, a foreign corporation or other foreign person will be required to file a federal income tax return and pay tax on his share of our taxable income because he will be regarded as being engaged in a trade or business in the United States as a result of his ownership of a Class A common unit.

Our registration with the Secretary of the Treasury as a "tax shelter" may increase your risk of an IRS audit.

Because we are a registered "tax shelter" with the Secretary of the Treasury, a unitholder may face an increased risk of an IRS audit resulting in taxes payable on our income as well as income not related to us. We could be audited by the IRS and adjustments to our income or losses could be made. Any unitholder owning less than a 1% profit interest in us has very limited rights to participate in the income tax and audit process. Further, any adjustments in our tax returns will lead to adjustments in the unitholders' tax returns and may lead to audits of unitholders' tax returns and adjustments of items unrelated to us. Each unitholder is responsible for any tax owed as the result of an examination of their personal tax return.

We have adopted certain valuation methodologies that may result in a shift of income, gain, loss and deduction between the general partner and the unitholders. The IRS may challenge this treatment, which could adversely affect the value of the Class A Common Units.

When we issue additional Class A Common Units or engage in certain other transactions, we determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our general partner. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and the general partner, which may be unfavorable to such unitholders. Moreover, subsequent purchasers of Class A Common Units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between the general partner and certain of our unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from our unitholders' sale of Class A Common Units and could have a negative impact on the value of the Class A Common Units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

We treat each purchaser of Class A Common Units as having the same tax benefits without regard to the actual Class A Common Units purchased. The IRS may challenge this treatment, which could result in a unitholder owing more tax and may adversely affect the value of the Class A Common Units.

To maintain the uniformity of the economic and tax characteristics of our Class A Common Units, we have adopted certain depreciation and amortization positions that are inconsistent with existing Treasury regulations. These positions may result in an understatement of deductions and losses and an overstatement of income and gain to our unitholders. For example, we do not amortize certain goodwill assets, the value of which has been attributed to certain of our outstanding Class A Common Units. A subsequent holder of those Class A Common Units is entitled to an amortization deduction attributable to that goodwill under Internal Revenue Code Section 743(b). However, because we cannot identify these Class A Common Units once they are traded by the initial holder, we do not give any subsequent holder of a Class A Common Unit any such amortization deduction. This approach understates deductions available to those unitholders who own those Class A Common Units and results in a reduction in the tax basis of those Class A Common Units by the amount of the deductions that were allowable but were not taken.

The IRS may challenge the manner in which we calculate our unitholder's basis adjustment under Internal Revenue Code Section 743(b). If so, because neither we nor a unitholder can identify the Class A Common Units to which this issue relates once the initial holder has traded them, the IRS may assert adjustments to all unitholders selling Class A Common Units within the period under audit as if all unitholders owned Class A Common Units with respect to which allowable deductions were not taken. Any position we take that is inconsistent with applicable Treasury regulations may have to be disclosed on our federal income tax return. This disclosure increases the likelihood that the IRS will challenge our positions and propose adjustments to some or all of our unitholders. A successful IRS challenge to this position or other positions we may take could adversely affect the amount of taxable income or loss allocated to our unitholders. It also could affect the gain from a unitholder's sale of Class A Common Units and could have a negative impact on the value of the Class A Common Units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

A description of our properties and maps depicting the locations of our liquids and natural gas systems are included in Item 1. Business, which is incorporated herein by reference.

In general, our systems are located on land owned by others and are operated under perpetual easements and rights of way, licenses or permits that have been granted by private land owners, public authorities, railways or public utilities. The pumping stations, tanks, terminals and certain other facilities of our systems are located on land that is owned by us, except for five pumping stations that are situated on land owned by others and used by us under easements or permits.

Substantially all of our Lakehead system assets are subject to a first mortgage lien collateralizing indebtedness of our Lakehead Partnership.

Titles to our properties acquired in the Midcoast system acquisition are subject to encumbrances in some cases. We believe that none of these burdens should materially detract from the value of these properties or materially interfere with their use in the operation of our business.

Item 3. Legal Proceedings

We are a participant in various legal proceedings arising in the ordinary course of business. Some of these proceedings are covered, in whole or in part, by insurance. We believe the outcome of all these proceedings will not, individually or in the aggregate, have a material adverse effect on our financial condition.

Item 4. Submission of Matters to a Vote of Security Holders

No matters were submitted to a vote of security holders during the fourth quarter of 2007.

PART II

Item 5. Market for Registrant's Common Equity and Related Unitholder Matters

Our Class A common units are listed and traded on the NYSE, the principal market for the Class A common units, under the symbol "EEP." The quarterly price ranges per Class A common unit and cash distributions paid per unit for 2007 and 2006 are summarized as follows:

	First	Second	Third	Fourth
2007 Quarters				
High	$ 56.23	$ 61.82	$ 58.47	$ 54.16
Low	$ 48.25	$ 52.30	$ 48.27	$ 48.71
Cash distributions paid	$ 0.925	$ 0.925	$ 0.925	$ 0.950
2006 Quarters				
High	$ 47.80	$ 44.80	$ 49.51	$ 50.99
Low	$ 42.88	$ 42.00	$ 43.26	$ 46.10
Cash distributions paid	$ 0.925	$ 0.925	$ 0.925	$ 0.925

On February 20, 2008 the last reported sales price of our Class A common units on the NYSE was $50.99. At February 12, 2008, there were approximately 80,000 Class A common unitholders, of which there were approximately 1,600 registered Class A common unitholders of record. There is no established public trading market for our Class B common units, all of which are held by the General Partner, our Class C units, which are held by the General Partner and institutional investors, or our i-units, all of which are held by Enbridge Management.

Item 6. Selected Financial Data

The following table sets forth, for the periods and at the dates indicated, our summary historical financial data. The table is derived, and should be read in conjunction with, our audited consolidated financial statements and notes thereto beginning at page F-1. See also "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

	Year ended December 31,				
	2007	2006	2005	2004	2003
	(dollars in millions, except per unit amounts)				
Income Statement Data:(2)(3)(4)					
Operating revenue	$ 7,282.6	$ 6,509.0	$ 6,476.9	$ 4,291.7	$ 3,172.3
Operating expenses	6,963.8	6,122.1	6,285.0	4,054.5	2,978.0
Operating income	318.8	386.9	191.9	237.2	194.3
Interest expense	99.8	110.5	107.7	88.4	85.0
Rate refunds	—	—	—	(13.6)	—
Other income	3.0	8.5	5.0	3.0	2.4
Income tax expense	5.1	—	—	—	—
Income from continuing operations	$ 216.9	$ 284.9	$ 89.2	$ 138.2	$ 111.7
Income from continuing operations per limited partner unit (basic and diluted)(1)	$ 2.08	$ 3.62	$ 1.06	$ 2.06	$ 1.93
Cash distributions paid per unit	$ 3.725	$ 3.700	$ 3.700	$ 3.700	$ 3.700
Financial Position Data (at year end):(2)(3)(4)					
Property, plant and equipment, net	$ 5,554.9	$ 3,824.9	$ 3,080.0	$ 2,778.0	$ 2,465.6
Total assets	6,891.6	5,223.8	4,428.4	3,770.7	3,231.8
Long-term debt, excluding current maturities	2,862.9	2,066.1	1,682.9	1,559.4	1,155.8
Loans from General Partner and affiliates	130.0	136.2	151.8	142.1	133.1
Partners' capital:					
Class A common units	1,340.7	1,141.7	1,142.4	1,021.6	914.9
Class B common units	72.9	67.6	67.2	66.7	64.2
Class C units	874.1	509.8	—	—	—
i-units	515.3	466.3	421.7	399.4	370.7
General Partner	62.9	47.6	34.6	31.0	27.5
Accumulated other comprehensive loss	(294.4)	(189.6)	(302.1)	(120.8)	(64.0)
Partners' capital	$ 2,571.5	$ 2,043.4	$ 1,363.8	$ 1,397.9	$ 1,313.3
Cash Flow Data:(2)(3)(4)					
Cash flows provided by operating activities	$ 463.4	$ 321.6	$ 267.1	$ 245.4	$ 148.2
Cash flows used in investing activities	1,765.0	867.0	437.1	419.1	431.0
Cash flows provided by financing activities	1,167.5	640.2	181.5	187.6	286.9
Additions to property, plant and equipment and acquisitions included in investing activities, net of cash acquired	1,980.2	897.7	531.2	429.8	423.5

Notes to Selected Financial Data:

(1) The allocation of net income to the General Partner in the following amounts has been deducted before calculating income per unit: 2007, $37.7 million; 2006, $30.9 million; 2005, $23.5 million; 2004, $22.5 million; and 2003, $19.6 million.

(2) Our income statement, financial position and cash flow data reflect the following acquisitions and dispositions:

- April 2006, acquisition of a natural gas pipeline in east Texas;

- December 2005, disposition of assets on the East Texas and South Texas systems;
- January 2005, acquisition of the natural gas gathering and processing asset in north Texas;
- March 2004 acquisition of the Mid-Continent system;
- December 2003 acquisition of the North Texas system;

(3) Our income statement, financial position and cash flow data include the effect of the following debt issuances:

- The December 2007 issuance of $130 million note payable to Enbridge Hungary Ltd. and the simultaneous repayment of a $145 million note payable to Enbridge Hungary Ltd., including $8.8 million of accrued interest.
- The September 2007 issuance of $400 million of junior subordinated notes;
- The August 2007 issuance of $200 million of zero coupon senior unsecured notes and $3.6 million of accreted interest;
- The April 2007 amendment of our credit facility, which increased the maximum principal amount of credit available to us at any one time from $1 billion to $1.25 billion, allows us to request increases in the maximum principal amount of credit available at any one time from $1.25 billion to $1.5 billion, eliminates the letter of credit sublimit and extends the maturity to 2012;
- The December 2006 issuance of $300 million of senior unsecured notes;
- The September 2005 amendment of our credit facility to extend the letter of credit sublimit from $175 million to $300 million and increase the commitments available from $600 million to $800 million maturing in 2010, and the subsequent extension of the commitments available to $1 billion in March 2006.
- The April 2005 establishment of a $600 million commercial paper program;
- The December 2004 issuance of $300 million of senior unsecured notes;
- The April 2004 amendment of our credit facilities to terminate the 364-day revolving credit facility and increase the Three-year term credit facility to $600 million maturing in 2007;
- The January 2004 issuance of $200 million of senior unsecured notes; and
- The May 2003 issuance of $400 million of senior unsecured notes.

(4) Our income statement, financial position and cash flow data include the effect of the following limited partner unit issuances:

- The May 2007 issuance of 5.3 million Class A common units;
- The April 2007 issuance of approximately 5.9 million Class C units to institutional investors;
- The August 2006 issuance of approximately 10.8 million Class C units in equal amounts to our general partner and an institutional investor;
- The December 2005 issuance of 0.13 million Class A common units; the November 2005 issuance of 3.0 million Class A common units; and the February 2005 issuance of 2.5 million Class A common units;
- The September 2004 issuance of 3.68 million Class A common units; and the January 2004 issuance of 0.45 million Class A common units;
- The December 2003 issuance of 5.0 million Class A common units; and the May 2003 issuance of 3.9 million Class A common units;
- The quarterly in-kind distributions of 0.9 million, 1.0 million, 0.8 million, 0.8 million and 0.8 million i-units during 2007, 2006, 2005, 2004 and 2003 respectively, in lieu of cash distributions;
- The quarterly in-kind distributions of 1.1 million and 0.2 million Class C units during 2007 and 2006, respectively, in lieu of cash distributions.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis of our financial condition and results of operations is based on and should be read in conjunction with our consolidated financial statements and the accompanying notes beginning on page F-1 of this Annual Report on Form 10-K.

RESULTS OF OPERATIONS—OVERVIEW

We provide services to our customers and returns for our unitholders primarily through the following activities:

- Interstate pipeline transportation and storage of crude oil and liquid petroleum;
- Gathering, treating, processing and transportation of natural gas and NGLs through pipelines and related facilities; and
- Supply, transportation and sales services, including purchasing and selling of natural gas and NGLs.

We conduct our business through three business segments: Liquids, Natural Gas and Marketing. These segments are strategic business units established by senior management to facilitate the achievement of our long-term objectives, to aid in resource allocation decisions and to assess operational performance.

The following table reflects our operating income by business segment and corporate charges for each of the years ended December 31:

	2007	2006	2005
		(in millions)	
Operating Income			
Liquids	$ 207.1	$ 199.8	$ 127.3
Natural Gas	91.2	133.9	110.5
Marketing	24.0	56.1	(42.4)
Corporate, operating and administrative	(3.5)	(2.9)	(3.5)
Total Operating Income	318.8	386.9	191.9
Interest expense	(99.8)	(110.5)	(107.7)
Other income	3.0	8.5	5.0
Income taxes	(5.1)	—	—
Income from continuing operations	216.9	284.9	89.2
Income from discontinued operations	32.6	—	—
Net Income	$ 249.5	$ 284.9	$ 89.2

Several types of arrangements in our Natural Gas and Marketing segments expose us to market risk associated with changes in commodity prices where we receive natural gas or NGLs in return for the services we provide, or where we purchase natural gas or NGLs. We employ derivative financial instruments to reduce our exposure to natural gas and NGL prices. Some of these derivative financial instruments do not qualify for hedge accounting under the provisions of Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities* (SFAS No. 133), which can create volatility in our earnings that can be significant. However, these fluctuations in earnings do not affect our cash flow. Cash flow is only affected when we settle the derivative financial instrument.

Summary Analysis of Operating Results

Liquids

Our Liquids segment includes the operations of our Lakehead, North Dakota and Mid-Continent systems. Each of these systems largely consists of FERC-regulated interstate crude oil and liquid petroleum pipelines. The Lakehead system, together with the Enbridge system in Canada, forms the longest liquid petroleum pipeline system in the world. Each of these systems generates most of its revenues by charging shippers a per barrel tariff rate to transport and store crude oil and liquid petroleum.

Our Liquids segment contributed operating income of $207.1 million in 2007, or $7.3 million more than the $199.8 million contributed in 2006. The operating income of our Liquids segment in 2007 was affected by the following factors:

- Modestly higher volumes on our Lakehead system derived from increased production of Western Canadian crude oil, partially offset by higher power costs associated with the increased volumes;
- The annual index rate increase effective July 1, 2007, which increased our average tariffs;
- Contract storage fees generated by the additional tankage added to our Cushing terminal; and
- Additional workforce related costs, pipeline integrity and casualty losses, partially offset by a reduction in field inventory expenses.

Natural Gas

Our Natural Gas segment consists of natural gas gathering and transmission pipelines, including three FERC-regulated interstate natural gas transmission pipelines, as well as natural gas treating and processing plants and related facilities. The revenues of our Natural Gas segment are derived from the fees we charge to gather and process natural gas and the rates we charge to transport natural gas on our pipelines.

Operating income from our Natural Gas segment declined to $91.2 million in 2007 from $133.9 million in 2006, a decrease of $42.7 million. The operating results of our Natural Gas segment are attributable to the following:

- Unrealized non-cash, mark-to-market net losses of $59.0 million, resulting from our derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133;
- Increased natural gas treating and processing capacity from the completion of new facilities on our East Texas and Anadarko systems, coupled with increased revenue less cost of natural gas derived from our processing assets resulting from a favorable pricing environment;
- Higher average daily volumes on our major natural gas systems during 2007 as compared with the same period in 2006, resulting from our continuing investments to expand the capacity of our three largest natural gas systems;
- Operational inefficiencies at our Zybach processing facility in early 2007 caused by fouling of the plant with contaminated water in the natural gas stream which reduced NGL production and increased operating costs;
- An increase in natural gas measurement losses on two of our major gathering systems in early 2007; and
- Additional operating and administrative costs and depreciation associated with the expansion of our natural gas systems.

Marketing

Our Marketing segment provides supply, transmission, storage and sales services to producers and wholesale customers on our gathering, transmission and customer pipelines, as well as other interconnected pipeline systems. Our Marketing activities are primarily undertaken to realize incremental revenue on gas purchased at the wellhead, increase pipeline utilization and provide other services that are valued by our customers.

Operating income from our Marketing segment decreased $32.1 million to $24.0 million in 2007 from $56.1 million for the comparable period in 2006. The change in operating income of our Marketing segment from 2007 to 2006 resulted from the following:

- Unrealized, non-cash mark-to-market net losses for 2007 of $3.8 million compared with non-cash mark-to-market net gains of $64.5 million for 2006, resulting from the change in market value of our derivative financial instruments that do not qualify for hedge accounting;
- Gains from the sale of natural gas inventory of approximately $16.3 million, including approximately $6.9 million of gains from the settlement of derivative financial instruments hedging our natural gas inventory;
- Non-cash charges of $4.3 million in 2007, resulting from a reduction of the cost basis of our natural gas inventory to market value, which is $12.7 million less than the $17.0 million we recorded in 2006; and
- Increased access to preferred natural gas markets associated with our natural gas system expansions and other initiatives.

Derivative Transactions and Hedging Activities

We record all financial instruments in our consolidated financial statements at fair market value pursuant to the requirements of SFAS No. 133. For those derivative financial instruments that do not qualify for hedge accounting, we record all changes in fair market value through our consolidated statements of income each period. The fair market value of our derivative financial instruments reflects the estimated amounts that we would pay or receive to terminate or close the contracts at the reporting date, although that is not our intent.

Rising NGL prices coupled with relatively stable natural gas prices produced $62.8 million of unrealized, non-cash mark-to-market net losses from hedges of our optional NGL production during the year ended December 31, 2007. We also incurred $1.4 million of unrealized, non-cash mark-to-market losses during 2007 in connection with interest rate swaps that do not qualify for hedge accounting treatment under SFAS No. 133. During the fiscal year ended December 31, 2006, declining natural gas prices produced non-cash mark-to-market net gains of $64.4 million and positively affected our operating results. Mark-to-market gains or losses create volatility in our operating results although the derivative financial instruments we have in place do not affect our cash flow until they are settled. We expect these non-cash gains and losses to reverse in future periods as we settle the derivative financial instruments against the underlying physical transactions. We intend to continue using derivative financial instruments to hedge our portfolio of natural gas and NGLs because of the economic benefit we derive from minimizing the volatility in our cash flows. Our continued use of derivative financial instruments may result in additional unrealized, non-cash gains or losses in the future.

The following table presents the unrealized gains and losses associated with changes in the fair value of our derivatives, which are recorded as an element of "Cost of natural gas" or in "Interest expense" in our consolidated statements of income and disclosed as a reconciling item on our consolidated statements of cash flows:

Derivative fair value gains (losses)	Year ended December 31, 2007	2006	2005
		(in millions)	
Natural Gas segment			
Hedge ineffectiveness	$ —	$ (1.9)	$ (2.5)
Non-qualified hedges	(59.0)	1.8	(5.6)
Marketing			
Non-qualified hedges	(3.8)	64.5	(41.3)
Discontinued hedges	—	—	(9.0)
Commodity derivative fair value gains (losses)	(62.8)	64.4	(58.4)
Corporate			
Non-qualified interest rate hedges	(1.4)	—	—
Derivative fair value gains (losses)	$ (64.2)	$ 64.4	$ (58.4)

De-designation and Settlement of Derivatives

In connection with the sale of assets in December 2005, as discussed in Note 3 to the consolidated financial statements beginning on page F-1 of this report, we settled for cash of approximately $16.3 million, natural gas collars representing derivative financial instruments on sales of 2,000 MMBtu/d of natural gas through 2011. We had previously recorded unrealized losses associated with the natural gas collars that were realized upon settlement. Additionally, we de-designated derivative financial instruments that qualified for and were designated as cash flow hedges of forecasted sales of 273 Bpd of NGLs through 2007 and contemporaneously closed out the position by entering into an offsetting derivative financial instrument, at market, on forecasted purchases of 273 Bpd of NGLs through 2007.

RESULTS OF OPERATIONS—BY SEGMENT

Liquids

Our Liquids segment includes the operations of our Lakehead, North Dakota, and Mid-Continent systems. We provide a detailed description of each of these systems in Item 1.—Business. The following tables set forth the operating results and statistics of our Liquids segment for the periods presented:

	Year Ended December 31,		
	2007	**2006**	**2005**
	(dollars in millions)		
Operating Results			
Operating revenues	$ 548.1	$ 512.8	$ 418.0
Operating and administrative	156.1	141.3	144.2
Power	117.0	107.6	74.8
Depreciation and amortization	67.9	64.1	71.7
Operating expenses	341.0	313.0	290.7
Operating Income	$ 207.1	$ 199.8	$ 127.3
Operating Statistics			
Lakehead system:			
United States(1)	1,202	1,204	1,036
Province of Ontario(1)	341	313	303
Total deliveries(1)	1,543	1,517	1,339
Barrel miles (billions)	408	400	338
Average haul (miles)	725	722	692
Mid-Continent system deliveries(1)	236	244	236
North Dakota system:			
Trunkline(1)	91	85	79
Gathering(1)	7	7	8
North Dakota system deliveries(1)	98	92	87
Total Liquids Segment Delivery Volumes(1)	1,877	1,853	1,662

(1) Average barrels per day in thousands.

Year ended December 31, 2007 compared with year ended December 31, 2006

Our Liquids segment accounted for $207.1 million of operating income in 2007, representing an increase of $7.3 million over 2006. The favorable results of our Liquids business reflect modest growth in our transportation volumes while actively managing the costs of our services. The majority of this increase related to improved results on our Lakehead system.

Operating revenue for the year ended December 31, 2007 increased by $35.3 million to $548.1 million from $512.8 million for the same period in 2006. The increase in revenue is primarily attributable to the higher delivery volumes on our Lakehead and North Dakota systems combined with the increase in average tariffs associated with the annual index rate increase that went into effect July 1, 2007, for all three of our liquids systems. We increased the transportation rates on our Lakehead system by an average of 4.5 percent and on our Ozark and North Dakota systems by an average of 4.3 percent. Additionally, new tariffs went into effect April 1, 2007, on our Lakehead system to reflect the annual calculation of the

SEP II and other surcharges based on true-ups of prior year amounts and estimates for 2007, as well as an adjustment for the Terrace surcharge due to lower than expected volumes moving on the Lakehead system in 2006. The tariff increases of our Liquids systems contributed approximately $15 million to the increase in our revenues for the year ended December 31, 2007.

Also contributing to the increase in revenues for the year ended December 31, 2007, was a $5 million increase in contract storage fees generated by our Mid-Continent storage terminal system from the additional storage tanks we placed in service during 2007 and in late 2006. Across our Mid-Continent system, we added a net of seven storage tanks during 2007 contributing an additional 3.8 million barrels of capacity bringing the total storage capacity to approximately 16.7 million barrels and 104 tanks. This additional storage capacity is expected to provide ongoing fixed, variable, and spot storage revenue.

Average delivery volumes on our Liquids systems increased to 1.877 million Bpd for the year ended December 31, 2007, from the 1.853 million Bpd during the same period in 2006, accounting for approximately $9 million of the increase in the operating revenues of our Liquids segment. The increase in average deliveries on our Liquids systems are primarily derived from modest production increases of Western Canadian crude oil delivered on our Lakehead system. The increase in deliveries is attributable to the following:

- Crude oil supplies increased from upstream production facilities associated with the ongoing development of the Alberta Oil Sands by producers;
- Our Mid-Continent system continues to operate near capacity; and
- Volume growth on our North Dakota system associated with completion of our hydrostatic testing program and phasing in portions of a system expansion that was completed in the fourth quarter of 2007.

Operating and administrative expenses for the year ended December 31, 2007 were $156.1 million, or $14.8 million greater than the $141.3 million for the same period in 2006. The increase in these costs is primarily attributable to the following:

- Additional workforce related costs associated with the operational, administrative, regulatory and compliance support necessary for our growing systems;
- Further costs we incurred in connection with our pipeline integrity program; and
- Property damage we sustained in connection with a crude oil release and fire on Line 3 of our Lakehead system.

Our general partner charges us the costs associated with employees and related benefits for personnel that are assigned to us or otherwise provide us with managerial and administrative services. The portion of compensation and related costs we are charged is dependent upon such items as estimated time spent, miles of pipe and headcount. We have experienced an increase in workforce related costs as a result of the growth and expansion of our Liquids system operations. We expect these costs will continue to increase in future periods as we continue to expand our Liquids system operations. The increase in operating and administrative costs is partially offset by a reduction for field inventory expenses we realized in 2006 that we did not incur in 2007.

Our pipeline systems consist of individual pipelines of varying ages from approximately 60 years to newly constructed. With appropriate inspection and maintenance the physical life of a pipeline is indefinitely long. However, as our pipelines age we anticipate that the level of expenditures required for inspection, renewal and maintenance will increase. In addition, we have established temporary pressure restrictions on some sections of some of our pipelines pending completion of specific inspection and renewal programs, and may from time to time establish further temporary pressure restrictions. Pressure restrictions reduce the available capacity of the applicable line segment and could result in a loss of throughput if and when the full capacity of that line segment would otherwise have been utilized. The loss of throughput to date, resulting from pressure restrictions, has not materially affected our operating results.

Oil measurement adjustments occur as part of the normal operations associated with our Liquids systems. The three types of oil measurement adjustments that normally occur on our systems include:

- Physical gains and losses, which result from evaporation, shrinkage, differences in measurement between receipt and delivery locations and other operational incidents;
- Degradation, which results from mixing at the interface between higher quality light crude oil and lower quality heavy crude oil; and
- Revaluation, which is a function of crude oil prices, the level of the carrier's inventory and the inventory positions of customers.

We identified operating conditions in 2005 on a connected third-party facility that contributed to higher levels of physical losses. We have addressed the operating conditions causing these higher levels of physical losses, which have subsequently reduced the physical losses we have experienced on our Lakehead system. We are seeking to recover damages for the losses we sustained from the owner of the third-party system, but can make no assurances that we will be successful in our efforts.

Power costs increased $9.4 million in 2007, compared with 2006, predominantly due to the higher utility rates we are charged by our power suppliers. The increase in delivery volumes is also a factor contributing to the additional power costs. We have experienced a trend of increasing electricity rates from our power suppliers due to higher natural gas costs.

Year ended December 31, 2006 compared with year ended December 31, 2005

Our Liquids segment accounted for $199.8 million of operating income in 2006, representing an increase of $72.5 million over 2005. The favorable results of the Liquids segment assets reflect continuing growth in our transportation volumes while actively managing the costs of our services. The majority of this increase related to significantly improved results on our Lakehead system.

Operating revenue in 2006 increased by $94.8 million to $512.8 million, compared with $418.0 million in 2005. As indicated in the table above, total delivery volumes of our Liquids segment averaged 1.853 million Bpd in 2006, representing a 0.191 million Bpd increase from the 1.662 million Bpd delivered in 2005. This accounted for an increase in operating revenues of approximately $48.0 million. The increases in deliveries on our Liquids systems are primarily derived from increased production of Western Canadian crude oil delivered on our Lakehead system. The increases in deliveries are attributable to the following:

- Suncor, an oil sands producer in Alberta, Canada, experienced a fire at its upgrader site in January 2005, which affected production for the majority of 2005. In late September 2005, Suncor completed repairs and an expansion to its upgrader site. Suncor's production levels have increased since that time.
- Conventional light, heavy crude oil and bitumen production have increased as existing and new facilities were commissioned during 2006.
- Syncrude, another oil sands producer in Alberta completed its Stage 3 expansion and initiated production on its Coker 8-3 unit in May 2006 enabling all Stage 3 units to be brought on line. Start-up issues were encountered and the full impact of this expansion was not realized until 2007. The Stage 3 expansion is designed to increase productive capacity from 250,000 Bpd to an average 350,000 Bpd of a light synthetic crude oil. Our deliveries in 2006 were marginally higher as a result of Syncrude's completion and start up of its Stage 3 expansion.

Contributing to the revenue growth of our Liquids segment are the increases in the average tariffs on all three of our Liquids systems. These tariff increases were partly the result of the annual index rate increase allowed by the FERC. On our Lakehead system, we increased our rates by an average of three percent. Also on our Lakehead system, new tariffs went into effect on April 1, 2006 for an adjustment on the Terrace expansion program surcharge due to lower than expected volumes moving on the Lakehead system, and new facilities in service, that were not operating during 2005. These tariff increases, along with the four percent increase in average hauls from 692 miles in 2005 compared with 722 in 2006 resulted in a combined increase in operating revenue of approximately $35.4 million.

Continuing volume growth related to our Mid-Continent storage terminal system in Cushing, Oklahoma, and El Dorado, Kansas, has resulted in an increase in operating revenue of approximately $6.8 million compared with 2005. Net capacity additions in 2006 bring the total storage capacity to 97 tanks and approximately 12.8 million barrels. This additional storage capacity is expected to provide ongoing fixed, variable, and spot storage revenue.

Operating and administrative expenses for 2006 were $141.3 million, or $2.9 million less than in 2005, primarily as a result of decreased oil measurement losses which are partially offset by increased workforce related costs and materials, supplies, and other general costs.

Workforce related costs increased due to the additional resources and related benefit costs we are charged for the operational, administrative, regulatory and compliance support necessary for our growing systems as discussed above in the year end analysis for December 31, 2007.

Materials, supplies and other expenses coupled with repair and maintenance costs were higher in 2006 compared with 2005 due to higher pipeline inspection costs associated with our pipeline integrity management programs, increased outside contractor services, field inventory adjustments and other general costs.

During the fourth quarter of 2005, we identified certain operating conditions on connected third-party systems that were contributing to higher levels of physical oil losses on our Lakehead system. Improvements to our oil measurement processes have resulted in fewer physical losses during 2006 on our Lakehead and Mid-Continent systems. We expect these improvements to have a continuing positive impact on our oil measurement losses going forward.

Power costs increased $32.8 million in 2006, compared with 2005, primarily due to the increase in volumes transported on our Lakehead system and higher electricity rates we are charged by our power suppliers. We have experienced a trend of increasing electricity rates from our power suppliers due to higher natural gas and other fuel costs.

We completed a depreciation study of the Lakehead system in the first quarter of 2006 that resulted in extending the composite remaining service life of the system assets from 21.5 to 26 years. The impact of the depreciation study was an $11.0 million reduction of depreciation expense for the full year of 2006.

Future Prospects for Liquids

Historically, Western Canada has been a key source of oil supply serving U.S. energy needs. Canada's oil sands, one of the largest oil reserves in the world, are becoming an increasingly prominent source of supply. Combined conventional and oil sands established reserves of approximately 179 billion barrels compare with Saudi Arabia's proved reserves of approximately 264 billion barrels. The National Energy Board of Canada, or NEB, estimates that total 2007 Western Canadian Sedimentary Basin, or WCSB, production averaged approximately 2.4 million Bpd compared with 2.3 million Bpd in 2006. According to production forecasts by CAPP, Western Canadian crude oil production is projected to grow progressively from approximately 2.4 million Bpd in 2007 to 5.2 million Bpd by 2020. Conventional crude oil production is expected to decline from approximately 1.0 million Bpd to approximately 670,000 Bpd over the same period. The net increased production is expected to result from an estimated $110 billion CAD of active or planned projects that are being developed in the oil sands. The projected growth in western Canadian crude production will require construction of new pipelines to ensure new oil supplies can be transported to markets in the United States.

We and Enbridge are actively working with our customers to develop transportation options that will allow Canadian crude oil greater access to markets in the United States.

Partnership Projects

Southern Access

In conjunction with Enbridge, we continue to progress on schedule with construction of the 400,000 Bpd Southern Access expansion project. We are undertaking the United States portion of the expansion on our Lakehead system. The first stage of construction will add approximately 190,000 Bpd of capacity and is on schedule for completion by the end of the first quarter of 2008. This stage of the project includes a new pipeline between Superior and Delavan, Wisconsin, along with pump station enhancements upstream and downstream of this segment.

The second stage of the expansion project will provide additional upstream pumping capacity and a new pipeline from Delavan to Flanagan, Illinois, with completion expected by the end of the first quarter of 2009. Completion of the total Southern Access expansion project will create a 454-mile pipeline with approximately 400,000 Bpd of incremental capacity on our Lakehead system.

As a result of the escalation of costs we have experienced with the first stage of the project for labor, materials and rights-of-way, we have revised our estimated cost to complete the project. We anticipate the ultimate cost to complete our portion of this project will approximate $2.1 billion. The impact on the project rate of return resulting from the escalation of costs is largely mitigated by the cost of service tolling arrangement used for this project. Approximately 88 percent of the cost overage will be included in the rate base, which forms the basis for determining our tariff rates for transportation. The remaining 12 percent of the project cost relates to installing larger pipe than required under current agreements which we are financing in anticipation of future expansion opportunities.

Alberta Clipper

The Alberta Clipper project involves construction of a new 36-inch diameter, 1,000 mile heavy crude oil pipeline from Hardisty, Alberta to Superior, generally within or adjacent to our and Enbridge's existing rights-of-way. We will construct approximately 330 miles of the new pipeline from the International Border near Neche, North Dakota to Superior and, at the request of our customers, we have revised the scope to also include a delivery connection at Clearbrook, Minnesota and an additional tank at Superior. Alberta Clipper will have an initial capacity of 450,000 Bpd and allows for expansions up to 800,000 Bpd by adding pump stations. In addition, complementary capacity on the Southern Access 42-inch pipeline from Superior to Flanagan will be obtained by installing additional pump stations. We anticipate that our share of the construction cost for the United States segment of the project will approximate $1.0 billion, in 2007 dollars, excluding capitalized interest. Alberta Clipper will be a common carrier line fully integrated with the Enbridge/Lakehead mainline systems for tolling purposes.

In May 2007, Enbridge filed an application with the NEB, for the construction and operation of the Canadian segment of the project. In June 2007, Enbridge filed supplements to this application setting forth the tolling principles for the Canadian portion of the project, which are supported by CAPP. Hearings for the Canadian section of the project began in November 2007. Regulatory and permit applications are in progress at state and federal levels. We plan to file a set of toll principles with the FERC similar to those filed by Enbridge with the NEB for the Canadian segment of the project. The project remains subject to regulatory approvals and receipt of various permits in Canada and the United States. Enbridge is progressing with land access, engineering and initial procurement commitments to facilitate commencement of project construction. Alberta Clipper is expected to be in service in mid-2010.

North Dakota

We substantially completed our expansion of the North Dakota system during the fourth quarter of 2007. The expansion added approximately 30,000 Bpd of mainline throughput capacity and expanded the system's feeder segment by approximately 30,000 Bpd at an approximate cost of $78.2 million. The expansion is supported by increasing crude oil production from the Bakken formation in the Williston Basin region of Montana and North Dakota.

Regional producers in the Williston basin areas of Montana and North Dakota have expressed interest in further expansion of pipeline capacity on our North Dakota system. We have proposed an approximate $0.15 billion additional expansion that will consist of upgrades to existing pump stations, additional tankage, as well as extensive use of drag reducing agents ("DRA") that are injected into the pipeline. This second expansion of our North Dakota system is expected to increase system capacity to 161,000 Bpd from the 110,000 Bpd that is currently available. The commercial structure for this expansion is a cost-of-service based surcharge that will be added to the existing tariff rates. The proposed surcharge is similar to the structure being used on the recently completed expansion project and is subject to approval from the FERC.

Superior and Griffith Storage

Due to forecasted production increases of synthetic heavy crude oil that we anticipate will be transported on the Enbridge/Lakehead mainline systems from Western Canada to Chicago, we are constructing additional crude oil storage tanks at Superior and Griffith to accommodate the anticipated volumes. We completed construction and placed into service one tank with approximately 330,000 barrels of operational capacity at Superior in August 2007 and another tank at Griffith with approximately 330,000 barrels of operational capacity in December 2007. We are also building two tanks with operational capacity of approximately 205,000 barrels each that are scheduled to be completed during 2008.

Mid-Continent Terminal Storage

We continue to experience strong interest from customers in securing access to long-term contract storage capacity at our Cushing, Oklahoma terminal. During 2006, we obtained commitments and initiated construction of an additional 5.0 million barrels of storage tanks, 1.1 million barrels of which were completed in late December 2006. During 2007, we completed construction of additional storage tanks with approximately 3.9 million barrels of capacity. Our total Mid-Continent terminal capacity is approximately 16.7 million barrels, which includes 1.4 million barrels of operational storage.

Enbridge and Other Projects

Spearhead Pipeline

In another effort to provide shippers access to new markets, Enbridge acquired a pipeline that runs from Cushing to Chicago, Illinois. The reversed pipeline, renamed Spearhead, began delivering Canadian crude oil to the major oil hub at Cushing in March 2006 and has operated at or near its capacity of 125,000 Bpd. In the first half of 2007, Enbridge successfully concluded a binding open season for expansion of the pipeline to 190,000 Bpd, with binding commitments for capacity of 30,000 Bpd. In December 2007, the FERC issued a favorable declaratory order effectively approving the tolling methodology and priority service for shippers with binding commitments. The Spearhead pipeline is complementary to our Lakehead system as Western Canadian crude oil is carried on our Lakehead system as far as Chicago, and then transferred to the Spearhead pipeline. The Spearhead pipeline expansion is expected to be in service in early 2009.

Southern Access Extension

In July 2006, Enbridge announced that it received support from shippers and CAPP for its 36-inch diameter Southern Access Extension pipeline from Flanagan, Illinois to Patoka, Illinois. The extension will broaden the reach of the Enbridge/Lakehead mainline system to incremental markets accessible from the Patoka hub. The project is scheduled for completion in the first quarter of 2009. This project is being undertaken by Enbridge, however, we will benefit from the incremental volumes moving through our Lakehead system to reach this extension. Enbridge filed a petition for declaratory order with the FERC in October 2007, which is currently pending approval.

Southern Lights

Following completion of a successful open season in 2006, Enbridge initiated its Southern Lights project to construct a diluent pipeline from Chicago, Illinois to Edmonton, Alberta, Canada to meet the growing demand for crude oil diluent required to transport the heavy oil and bitumen (a thick, tar-like form of oil) being produced in increasing volumes from the Alberta oil sands. The project involves the exchange of a 156-mile section of pipeline we own for a similar section of a new pipeline to be constructed as part of the project. In addition, this project involves a reconfiguration of our light crude mainline system which will provide an additional 45,000 Bpd of effective capacity at no cost to us. We expect to benefit from increased heavy crude oil shipments, which will be facilitated by the diluent line.

Enbridge has filed applications with the NEB for approval of all facets of the Canadian portion of the project and the majority of necessary applications for the United States portion of the project with United States federal and state regulatory agencies. Enbridge filed a petition for declaratory order with the FERC setting forth the rate structure for establishing tolls and the proposed swap of line 13 discussed above, which the FERC approved in late December 2007. In conjunction with our Southern Access project, the Southern Lights project has been allowed the right to exercise eminent domain for right-of-way in Illinois. Early construction and right-of-way acquisition related to this project continues in tandem with stage one of the Southern Access project. This project is expected to be placed in service in 2010.

Texas Access Pipeline

Non-binding expressions of interests received in June 2007 demonstrated strong shipper support for the construction of a new heavy crude oil pipeline system to transport crude oil from Patoka, Illinois to the U.S. Gulf Coast. Enbridge (U.S.) Inc. and ExxonMobil Pipeline Company are jointly pursuing development of the Texas Access Pipeline, which as proposed will provide approximately 445,000 Bpd of new capacity from Patoka, Illinois to Texas Gulf Coast refineries with a projected in-service date of mid-2011. The proposed project comprises a new 768-mile, 30-inch diameter pipeline that begins in the vicinity of Mobil Pipe Line Company's Patoka, Illinois crude oil terminal southward to Nederland, Texas, coupled with an 88-mile, 24-inch lateral to transport crude oil onward from Nederland to a delivery point in Houston, Texas. The new pipeline will allow for connectivity to existing terminals in both Nederland and Houston, and will be constructed in the same corridor with existing pipelines owned by ExxonMobil Pipeline Company. The initial capacity of the Patoka-to-Nederland segment of the pipeline would be 445,000 Bpd, and the initial capacity of the Nederland-to-Houston segment would be 169,000 Bpd.

In December 2007, an open season was announced to solicit binding 15-year shipper commitments for the proposed Texas Access Pipeline, which ends on March 14, 2008. Construction of this project would complement our Lakehead system and further support its expansion.

Eastern PADD II Access

Enbridge has held discussions with several refiners in the eastern United States to gauge interest in supporting the development of a pipeline to provide incremental pipeline capacity to this market. Development of this project is ongoing and is expected to provide up to approximately 100,000 Bpd of heavy Canadian crude oil to the Eastern PADD II market by late 2010. Additional access initiative discussions have commenced with other area refiners to provide incremental infrastructure in this area for service in the 2013 timeframe. Construction of both of these projects would be complementary to our Lakehead system.

Other Matters

In September 2007, the Alberta Royalty Review Panel issued its recommendations to the government of the Province of Alberta calling for the adoption of measures to increase the Alberta government's share of revenues from oil sands development. A majority of the recommendations of the report were subsequently adopted by the Alberta government and will become effective January 1, 2009. These measures may impact how oil sands developers evaluate future projects and this may reduce the level of future volumes we expect to flow through the Enbridge/Lakehead mainline system.

Natural Gas

Our Natural Gas segment consists of natural gas gathering and transmission pipelines, as well as treating and processing plants and related facilities. Collectively, these systems include:

- approximately 11,500 miles of natural gas gathering and transmission pipelines including three FERC-regulated transmission pipeline systems;
- 10 natural gas treating plants;
- 24 natural gas processing plants including three recently installed hydrocarbon dewpoint control facilities; and
- trucks, trailers and railcars used for transporting NGLs, crude oil and carbon dioxide.

The following tables set forth the operating results of our Natural Gas segment assets and average daily volumes of our major systems in MMBtu/d for the periods presented:

	Year Ended December 31,		
	2007	**2006**	**2005**
		(dollars in millions)	
Operating revenues	$ 3,444.0	$ 3,020.7	$ 2,352.1
Cost of natural gas	2,990.0	2,601.1	2,018.7
Operating and administrative	266.7	215.4	175.0
Depreciation and amortization	96.1	70.3	66.0
Gain on sale of assets	—	—	(18.1)
Expenses	3,352.8	2,886.8	2,241.6
Operating income	$ 91.2	$ 133.9	$ 110.5
East Texas(2)	1,180,000	1,019,000	860,000
Anadarko	591,000	582,000	488,000
North Texas	348,000	294,000	265,000
UTOS	192,000	181,000	158,000
Midla	115,000	109,000	106,000
AlaTenn	44,000	41,000	59,000
Bamagas	119,000	88,000	29,000
Other Major Intrastates(3)	236,000	223,000	230,000
Total	2,825,000	2,537,000	2,195,000

(1) In November 2007, we sold the KPC system which contributed average daily volumes of approximately 23,000, 29,000 and 31,000 for the years ended December 31, 2007, 2006 and 2005.

(2) In December 2005, we sold the South Texas assets and a sour gas system in East Texas which had a combined average daily volume of approximately 55,000 MMBtu/d, of this amount 33,000 MMbtu/d relates to South Texas.

(3) We have included in other major intrastates the volumes of our Gloria system for the years ended December 31, 2007, 2006, and 2005 of 62,000, 65,000, and 44,000.

We recognize revenue upon delivery of natural gas and NGLs to customers, when services are rendered, pricing is determinable and collectibility is reasonably assured. We derive revenue in our Natural Gas segment from the following types of arrangements:

Fee-Based Arrangements:

Under a fee-based contract, we receive a set fee for gathering, treating, processing and transporting raw natural gas and providing other similar services. These revenues correspond with the volumes and types of services provided and do not depend directly on commodity prices. Revenues of the Natural Gas segment that are derived from transmission services consist of reservation fees charged for transmission of natural gas on the FERC-regulated interstate natural gas transmission pipeline systems, while revenues from intrastate pipelines are generally derived from the bundled sales of natural gas and transmission services.

Other Arrangements:

We also use other types of arrangements to derive revenues for our Natural Gas segment. These arrangements expose us to commodity price risk, which we substantially mitigate with offsetting physical purchases and sales and by the use of derivative financial instruments to hedge open positions. We will continue to hedge a significant amount of our commodity price risk to support the stability of our cash flows. Refer to Item 7A. Quantitative and Qualitative Disclosures about Market Risk—Commodity Price Risk and Note 14 of our consolidated financial statements beginning on page F-1 of this report for more information about the derivative activities we use to mitigate this commodity price risk.

These other types of arrangements are categorized as follows:

- Percentage-of-Liquids Contracts—Under these contracts, we receive a negotiated percentage of NGLs and condensate extracted from natural gas that requires processing, which we then sell at market prices and retain as our fee. This contract structure is similar to percentage-of-proceeds arrangements except that we only receive a percentage of the NGLs and condensate.

- Keep-Whole Contracts—Under these contracts, we gather or purchase raw natural gas from the producer for processing. A portion of the gathered or purchased natural gas is consumed during processing. We extract and retain the NGLs produced during processing for our own account, which we sell at market prices. In instances where we purchase raw gas at the wellhead, we also sell for our own account at market prices, the resulting residue gas. In those instances when we gather and process raw natural gas for the account of the producer, we must return to the producer residue gas with an energy content equivalent to the original raw natural gas we received as measured in British thermal units, or Btu.

- Percentage-of-Index Contracts—Under these contracts, we purchase raw natural gas at a negotiated discount to an agreed upon index price. We then resell the natural gas, generally for the index price, keeping the difference as our fee.

- Percentage-of-Proceeds Contracts—Under these contracts, we receive a negotiated percentage of the natural gas and NGLs we process in the form of residue natural gas, NGLs, condensate and sulfur, which we then sell at market prices and retain as our fee.

Under the terms of each of these contract structures, we retain a portion of the natural gas and NGLs as our fee in exchange for providing these producers with our services. In order to protect our cash flows from volatility that can result from fluctuations in commodity prices, we enter into derivative financial instruments to effectively fix the sales price of the natural gas and NGLs we anticipate receiving under the terms of these contracts. We target approximately 70 to 80 percent hedge coverage of our anticipated near-term exposure to commodity prices using derivative financial instruments. As a result of entering into these derivative financial instruments, we have largely fixed the amount of cash that we will receive in the future when we sell the processed natural gas and NGLs, although the market price of these commodities will continue to fluctuate during that time.

Year ended December 31, 2007 compared with year ended December 31, 2006

Our Natural Gas segment produced $91.2 million of operating income for the year ended December 31, 2007, a decrease of $42.7 million from the $133.9 million of operating income generated during the prior year. Operating income in 2007 included unrealized, non-cash mark-to-market net losses from our derivative activities totaling $59.0 million which are $58.9 million more than the $0.1 million of net losses we recorded in the same period of 2006. Also contributing to operating income were volume increases, improved pricing for our services and greater processing margins, which represent revenues less the cost of natural gas purchased for processing. Partially offsetting these increases in operating income were higher operating costs and depreciation.

The operating income of our Natural Gas segment for the year ended December 31, 2007 was negatively affected by unrealized non-cash, mark-to-market net losses of $59.0 million from our derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133. These losses were predominantly the result of hedges placed on the optional processing we perform on our three major systems which do not qualify for hedge accounting. In 2006, our operating income was reduced by unrealized non-cash, mark-to-market net losses of $0.1 million, including $1.9 million of losses that resulted from ineffectiveness of our cash flow hedges and $1.8 million of gains derived from our derivative financial instruments that did not qualify for hedge accounting treatment under SFAS No. 133. Refer also to Item 7A. Quantitative and Qualitative Disclosures about Market Risk—Commodity Price Risk and Note 14 of our consolidated financial statements beginning on page F-1 of this report for more information about our derivative activities.

Average daily volumes on our major natural gas systems increased 11 percent, or approximately 288,000 MMBtu/d, for the year ended December 31, 2007, compared with the corresponding period of 2006. The increased volumes for 2007 continue to reflect our ongoing investments to further expand the capacity of our systems and services. We completed the following projects during 2007 and 2006 which have contributed to the increases in average daily volumes and operating results of our major natural gas systems:

- Construction of our Henderson natural gas processing facility on our East Texas system was completed and operating at the end of the third quarter of 2006 with a capacity of 120 MMcf/d;

- A link between our North Texas and East Texas systems became fully operational during the third quarter of 2006, increasing the utilization of our 500 MMcf/d East Texas intrastate pipeline that we placed in service in June 2005;

- Various segments of our East Texas Expansion and Extension project (Project Clarity) including the following:

  - A 24-inch diameter pipeline that runs from the Marquez treating facility to Crockett, Texas and the 36-inch diameter pipeline that runs from Crockett to Goodrich, Texas were both completed and placed into service in late March 2007;

  - The Marquez treating plant with capacity of approximately 200 MMcf/d and additional pipeline capacity to the existing southeast section of this area was completed and placed into service in March 2007;

  - A 20-inch diameter pipeline in close proximity to our Marquez treating facility was completed and placed into service in June 2007;

  - A 36-inch diameter pipeline that extends from an interconnect with our existing pipeline at Bethel, Texas to Crockett was completed and placed into service in late July 2007;

  - A 36-inch diameter pipeline that extends from Goodrich to Kountze was completed in October 2007, which enables deliveries into a major interstate pipeline;

- Expansion of our existing 275 MMcf/d Aker treating facility was completed in 2007 and additional expansions are underway at this facility in 2008;

- Construction of the Hidetown processing facility on our Anadarko system with approximate capacity of 120 MMcf/d was completed and placed into service at the end of April 2007;

- During the second quarter of 2007, we refurbished our Zybach processing plant to address operational inefficiencies experienced by the plant. As a result of the service and repairs, processing volumes were restored to expected levels; and

- Construction of the Weatherford gas processing facility within our North Texas system was completed in September 2007 with a processing capacity of approximately 35 MMcf/d. At the end of 2007, additional processing capacity was added to the Weatherford processing facility to increase its capacity from 35 MMcf/day to 75/MMcf/day.

- In addition to the investments we have made to expand the volumes in areas served by our natural gas assets, the volume and revenue growth is also the result of additional wellhead supply contracts and robust drilling activity in the Bossier Trend and Barnett Shale areas. We expect increasing volumes on our major natural gas systems to result from our continuing investments to expand the capacity of our systems to provide gathering, processing and transportation services to meet the needs of producers in the areas we serve.

During 2007, we have added approximately 195 MMcf/d of additional processing capacity to our Natural Gas systems, which has served to increase our processing margin. During 2007, NGL prices continued to trend higher relative to natural gas prices, providing a favorable environment for the production of NGLs from our processing assets, similar to the pricing environment experienced during 2006. A variable element of our Natural Gas segment's operating income is derived from the processing of natural gas under keep-whole arrangements that exist within our East Texas, North Texas and Anadarko systems. Operating income derived from our keep-whole processing increased to approximately $108.8 million for the year ended December 31, 2007 from $79.2 million for the same period in 2006 primarily due to the current favorable pricing environment and increased volumes processed associated with these types of arrangements and increased processing plant capacity. Partially offsetting our favorable processing results were operational issues associated with our Zybach processing plant that occurred during the first quarter of 2007 which reduced processing margins by approximately $10.5 million. We completed the necessary repairs and modifications during April 2007 and the plant has since been operating as expected throughout the remainder of 2007.

Natural gas measurement losses occur as part of the normal operating conditions associated with our natural gas pipelines. The quantification and resolution of measurement losses is complicated by several factors including varying qualities of natural gas in the streams gathered and processed through our systems, changes in weather temperatures and variances in measurement that are inherent in metering technologies. During the first quarter 2007, we identified operating conditions on our gathering systems which contributed to an increase in measurement losses. We have since installed separator equipment to identify and eliminate free-water in the natural gas streams, one of the underlying causes for the increase in measurement losses during 2007. For the year ended December 31, 2007, we estimate that measurement losses resulted in approximately $21.3 million of additional cost to our natural gas systems relative to the same period of 2006.

A portion of our Natural Gas segment is exposed to risks from fluctuations in commodity prices associated with the percentage of proceeds, percentage of liquids, and percentage of index contracts that we negotiate with producers. Under the terms of these contracts, we retain a portion of the natural gas and NGLs we process in exchange for providing these producers with our services. In order to protect our unitholders from the volatility in cash flows that can result from fluctuations in commodity prices, we enter into derivative financial instruments to fix the sales price of the natural gas and NGLs we anticipate receiving under the terms of these contracts. We target approximately 70 to 80 percent hedge coverage of our anticipated near-term exposure to commodity prices using derivative financial instruments. As a result of entering into these derivative financial instruments, we have largely fixed the amount of cash that we will pay for natural gas and receive in the future when we sell the processed natural gas and NGLs, although the market price of these commodities will continue to fluctuate during that time. Another significant portion of the revenue we receive is derived from fees charged for gathering and treating of natural gas volumes and other related services which are not directly dependent on commodity prices.

Operating and administrative costs associated with our Natural Gas segment were $51.3 million, or 24 percent, greater for 2007 than 2006, primarily as a result of increased workforce related cost associated with the expansion of our systems, maintenance activities and other costs that are mostly variable with volumes. Our workforce related costs increased for the year ended December 31, 2007 over the same period in 2006 due to the additional resources and related benefit costs we are charged for the operational, administrative, regulatory and compliance support necessary for our existing assets and the expansion of our natural gas operations. In addition, our general partner charges us the costs associated with employees and related benefits for personnel that are assigned to us or otherwise provide us with managerial and administrative services. The portion of compensation and related costs we are charged is dependent upon such items as estimated time spent, miles of pipe and headcount. In addition we have experienced an increase in outside contract labor cost, given the high demand and competitive rates within our industry as a result of continuous pipeline expansions across the areas we serve.

Our materials and supplies coupled with repair and maintenance costs increased for the year ended December 31, 2007 over the same period in 2006, predominantly due to the increase in volumes and expansion of our natural gas systems. Materials, supplies and other costs include chemicals used in our processing activities, materials purchased for repair and maintenance purposes, utility costs to run our plants, pumps and other similar costs that are mostly variable with volumes. Repair and maintenance costs include compressor maintenance, downtime for routine and unscheduled maintenance, pipeline integrity costs and other similar items that have increased with the expansion of our existing natural gas systems. An example of these increasing costs is methanol, a chemical used on our systems which cost $2.06 per gallon in 2006. At the end of 2007, this chemical had risen in cost to $2.49 per gallon. Welders, inspectors and other skilled laborers and technicians hourly labor costs have increased in cost by amounts well in excess of the rate of overall inflation as measured by the CPI or PPI inflation index. We expect our operating and administrative costs will continue to increase in future periods as greater volumes of natural gas flow through our systems and we continue to expand our natural gas operations.

Our depreciation and amortization expense for the year ended December 31, 2007 increased by approximately $25.8 million over the same period in 2006, primarily as a result of capital projects completed and placed in-service during late 2006 and throughout 2007. We expect our depreciation expense to continue to increase as we complete capital projects related to our continued expansion of our natural gas operations.

Year ended December 31, 2006 compared with year ended December 31, 2005

Our Natural Gas segment contributed $133.9 million of operating income in 2006, an increase of $23.4 million from the $110.5 million it contributed in 2005. The increase in operating income is primarily attributable to favorable commodity prices which contributed to higher revenue generated by our processing assets in excess of the cost we incur for the natural gas used in processing. Additionally, operating income was higher due to volume increases on each of our three largest systems resulting from additional wellhead supply contracts and the expansion of our transportation and processing capacity. Partially offsetting the benefit provided by favorable volumes and commodity prices are expenses we recorded in 2006 of approximately $8.3 million for NGL purchases and transportation and fractionation charges that relate to prior years we had not previously recorded. Our 2006 volumes and operating results are exclusive of the volumes and operating results associated with our December 2005 sale of the South Texas assets and a sour gas system located on our East Texas system.

Average daily volumes on our major natural gas systems were up approximately 13 percent in 2006, compared with 2005. Increases in our volumes for 2006 are attributable to our ongoing investments to expand the capacity of our systems and services. Our investments in the following projects that were completed during 2006 contributed to the increase in the average daily volumes and operating results on our major natural gas systems:

- The link between our North Texas and East Texas systems became fully operational during the third quarter of 2006, increasing the utilization of our 500 MMcf/d East Texas intrastate pipeline that we placed in service in June 2005;

- Construction of our 120 MMcf/d Henderson natural gas processing facility on our East Texas system was completed at the end of the third quarter of 2006 and processed volumes of approximately 100 MMcf/d;

- The expansion of our existing Zybach processing facility on our Anadarko system to a capacity of 150 MMcf/d of natural gas from an initial capacity of 105 MMcf/d to meet the continuing demands resulting from rapid development in the Anadarko basin; and

- Acquisition of an 80-mile pipeline in April 2006 that is complimentary to our existing East Texas system that provided approximately 75,000 MMBtu/d of incremental volume.

In addition to the investments we have made to expand our volumes in the areas served by our natural gas assets, the volume and revenue growth is also the result of additional wellhead supply contracts and robust drilling activity in the Anadarko basin, Bossier Trend and Barnett Shale.

Throughout a majority of 2006, we have experienced a favorable pricing environment with regard to our assets and our processing. During 2006, NGL and crude oil prices remained high relative to natural gas prices which have declined from the high prices reached in late 2005. This increase includes the contribution to operating income derived from our keep-whole processing, of $79.2 million, including $19.1 million from our North Texas system, for the year ended December 31, 2006, in excess of the $29.0 million generated in 2005 under this contract structure. Due to the volatility associated with commodity prices, the revenue less cost of natural gas we derive from our processing activities in future periods could be adversely affected if the pricing environment becomes unfavorable, which can occur if the prices for NGLs substantially decline and the price of natural gas significantly increases. We attempt to hedge a majority of our mandatory processing to minimize the effects volatility in commodity prices can have on our processing activities.

Operating income of our Natural Gas segment for the year ended December 31, 2006 includes unrealized non-cash, mark-to-market net losses of $0.1 million, including $1.9 million of losses resulting from ineffectiveness of our cash flow hedges and $1.8 million of gains derived from our derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133. In 2005, our operating income was reduced by $8.1 million of unrealized, non-cash, mark-to-market net losses that we incurred, primarily from derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133. The decline in our unrealized derivative fair value losses in 2006 is largely due to a decline in the current and forward prices of natural gas and NGLs during 2006 from the high levels reached in 2005 due to hurricanes Rita and Katrina that caused supply disruptions in the Gulf of Mexico resulting in a volatile pricing environment. Additionally, our unrealized derivative fair value losses in 2006 are lower due to our settlement in December 2005 for $16.3 million of natural gas collars on 2,000 MMBtu/d of natural gas through 2011 that did not qualify for hedge accounting treatment under SFAS No. 133. The settlement of these natural gas collars reduces the quantity of derivatives outstanding that do not qualify for hedge accounting treatment in our Natural Gas segment, effectively reducing the unrealized mark-to-market adjustments resulting from these derivatives in periods following settlement. Refer to Item 7A. Quantitative and Qualitative Disclosures about Market Risk—Commodity Price Risk and Note 14 of our consolidated financial statements beginning on page F-1 of this report for more information about our derivative activities.

Operating and administrative costs of our Natural Gas segment were $215.4 million, or 23 percent, greater for 2006 than 2005, primarily as a result of increased workforce related costs, maintenance activities and other costs that are mostly variable with volumes. Workforce related costs have increased due to the additional resources and related benefit costs we are charged for the operational, administrative, regulatory and compliance support necessary for our existing assets and the expansion of our natural gas operations.

The increase in our Materials, supplies and other costs along with our Repair and maintenance costs are predominantly related to the increase in volumes and expansion of our natural gas systems. Materials, supplies and other costs include chemicals used in our processing activities, materials purchased for repair and maintenance purposes, utility costs to run our plants, pumps and other similar costs that are mostly variable with volumes. These costs were partially offset by the sale of our South Texas assets and a sour gas system located on our East Texas system in December 2005, which contributed to the decrease in Materials, supplies and other costs compared with 2005. Repair and maintenance costs include compressor maintenance, downtime for routine and unscheduled maintenance, pipeline integrity costs and other similar items that have increased with the expansion of our existing natural gas systems. During 2006, we spent approximately $10.1 million, the majority of which was in the fourth quarter of 2006, on pipeline integrity work in connection with our ongoing pipeline integrity management program in order to comply with regulatory guidance and maintain our existing pipeline integrity standards. We anticipate these costs will continue to increase as we expand our systems and increase the volumes of natural gas services we provide.

Our other operating and administrative costs include rents and leases which primarily relate to compressor rentals, property taxes and other costs. These additional operating and administrative costs tend to vary in relation to the natural gas volumes moving on our systems or in relation to the expansion of our natural gas operations. We anticipate these costs will continue to increase as the volumes on our systems increase and we expand our systems.

Our depreciation and amortization expense for the year 2006 exceeded the amount reported for 2005 by approximately $4.3 million, primarily as a result of capital projects completed and placed in-service during 2006 and projects completed in 2005 that were only depreciated for a partial year. The increase in depreciation expense was partially offset by modest extensions of the depreciable lives of our major natural gas systems based on a third-party study commissioned by management that was completed in the third quarter of 2005. As a result of this study, revised depreciation rates for the Anadarko, North Texas and East Texas systems were implemented effective August 1, 2005. The annual composite rate, which represents the expected remaining service life of these natural gas systems, was reduced from 4.0% to 3.4%. As a result, our depreciation expense was approximately $3.5 million and $2.5 million lower for the years ended December 31, 2006 and 2005, respectively, than if these rates had not been reduced. Additionally, we revised our depreciation rates for a portion of our FERC-regulated natural gas assets effective July 1, 2006, to reflect a decrease in the remaining service life of these natural gas assets. Depreciation expense was approximately $1.3 million higher for the year ended December 31, 2006, as a result of this decrease in the expected remaining service life of these assets.

Future Prospects for Natural Gas

Our natural gas assets are located in the Gulf Coast and Mid-continent regions of the United States, two of the premier natural gas producing areas. As a result, there are many opportunities to connect new natural gas supplies either by installing new facilities or acquiring adjacent third-party gathering operations. Consolidation with neighboring facilities will extract efficiencies by eliminating costs, for example, by combining redundant facilities, increasing volume, and increasing processing margins. These opportunities tend to involve modest amounts of capital with attractive rates of return.

We continue to assess various expansion opportunities to pursue our strategy for growth. While we remain committed to making accretive acquisitions in or near areas where we have a competitive advantage, we will continue to focus our efforts primarily on development of our existing pipeline systems. We may, and have, pursued opportunities to divest any non-strategic natural gas assets as conditions warrant.

Results of our natural gas gathering and processing business depend upon the drilling activities of natural gas producers in the areas we serve. During 2007, increased drilling in the areas where our gathering systems are located contributed to the growth of volumes on our systems. We expect the growth trend in these areas to continue in the future as evidenced by external production forecasts and the strong rig counts and permitting in the areas served by our systems.

Producer plans for drilling in the areas served by our natural gas assets are expected to result in continued production growth on our natural gas systems. To accommodate this further growth, we initiated construction on several projects to increase our gathering, processing, transportation and treating infrastructure, as well as market access capability and have completed a number of these projects as discussed above under our analysis for 2007. The remaining projects listed below continue to progress and include:

East Texas System Expansion and Extension (Project Clarity):

- The expansion and extension of our East Texas natural gas system, referred to as the Clarity project, includes construction of a 36-inch diameter intrastate pipeline from Bethel, Texas to Orange, Texas with capacity of approximately 700 MMcf/d. Pipeline construction is expected to be completed in the first quarter of 2008. Additional capacity to downstream interconnects will increase as compression is added through mid-2008. The pipeline will provide service to a number of major industrial companies in Southeast Texas with interconnects to interstate pipelines, intrastate pipelines and wholesale customers. We continue to secure additional commitments for capacity on the pipeline. Our expectation is that the ultimate cost to complete the construction of this project will approximate $635 million.

Other East Texas Projects:

- The expansion of our sour gas treating capacity on the East Texas system will increase the total sulfur capacity from 72.5 tons per day (tpd) to 125 tpd by early 2008, in order to handle additional sour gas supply and higher concentration levels of hydrogen sulfide (H_2S).

- We have completed construction of three hydrocarbon dewpoint control facilities on our East Texas system to add processing capacity to meet the increasingly more stringent pipeline gas quality specifications. We completed and placed into service facilities, which we refer to as Henderson II, Grapeland, and Carthage hydrocarbon dewpoint control facilities. These facilities have a cumulative capacity of 550 MMcf/d and obtain a significant portion of their revenues from fees rather than keep-whole processing or percentage-of-liquids revenues.

- In the first quarter of 2008 we completed construction of a 25-mile, 20-inch diameter pipeline from a lateral on our East Texas system to gather additional production being developed in East Texas, which we expect will be transported on the Clarity system to markets in Southeast Texas.

North Texas System Projects:

In order to accommodate the active development and anticipated growth occurring in the Barnett Shale play in North Texas we commenced construction of two natural gas processing plants and related upstream facilities with a combined total capacity of approximately 75 MMcf/d. During the third quarter 2007, we placed the 35 MMcf/d Weatherford processing facility in service and completed construction on a further expansion of 40 MMcf/d in the fourth quarter of 2007.

Anadarko System Projects:

We continue to increase our field compression in the Anadarko region, which we expect will begin contributing to our operating results during the remainder of 2008.

When fully operational, we expect that the new assets we are constructing will provide additional sources of cash flow for us. We continue to evaluate other projects that could further integrate our major Texas-centered natural gas pipeline systems.

Other Matters

A number of new interstate natural gas transportation pipelines are being constructed that may alter interstate transportation of natural gas. These newly constructed pipelines could affect the operating results of certain of our existing market-based interstate and intrastate natural gas pipelines, primarily the AlaTenn, Midla, and MLGT systems. Conversely, our supply based gathering systems may benefit from enhanced capacity out of our gathering areas.

We recently initiated negotiations with a major customer of our Enbridge Pipelines (Midla), L.L.C., or Midla, mainline transmission system for the renewal of a contract that is set to expire in August 2008. The ultimate outcome of these negotiations is uncertain. The modest amount of operating income we derive from the Midla mainline transmission system could be reduced in the event the customer terminates the contract or renews it at lower rates than we currently charge. Further, such an outcome could reduce Midla's ability to recover the carrying value of its noncurrent assets, which approximate $34 million at December 31, 2007.

In November 2007, we sold our Kansas pipeline system, or KPC, to an unrelated party for $133 million in cash, subject to adjustments for working capital items. KPC is an interstate natural gas transmission system, which serves the Wichita, Kansas and Kansas City, Kansas markets and includes approximately 1,120 miles of pipeline ranging in diameter from 4 to 12 inches, along with three compressor stations. KPC represents a business within our Natural Gas segment that we do not consider strategic to the ongoing central operations of our core Natural Gas segment assets. The operating results of the KPC system were not material to our consolidated operating results or those of our Natural Gas segment for the years ended December 31, 2007, 2006 and 2005. We recognized a gain of $32.6 million on the sale of KPC, which is presented in income from discontinued operations.

In December 2005, Calpine Corporation ("Calpine") and many of its subsidiaries, including the subsidiary that owns the two utility plants served by our Bamagas system, filed voluntarily petitions to restructure under Chapter 11 of the United States Bankruptcy Code. Since filing for bankruptcy, Calpine has continued to perform under the terms of its agreements with Bamagas. In June 2007, Calpine and certain of its subsidiaries filed a Joint Plan of Reorganization (the "Plan") and Disclosure Statement with the United States Bankruptcy Court. On December 19, 2007 the U.S. Bankruptcy Court for the Southern District of New York issued a decision confirming Calpine's reorganization plan. In addition, the Bamagas contracts with Calpine have been reaffirmed. Calpine announced at the end of January 2008 that it has emerged from Bankruptcy.

Marketing

The following table sets forth the operating results for the Marketing segment assets for the periods presented:

	Year Ended December 31,		
	2007	2006	2005
	(dollars in millions)		
Operating revenues	$ 3,290.5	$ 2,975.5	$ 3,706.8
Cost of natural gas	3,256.9	2,913.5	3,744.6
Operating and administrative	8.0	5.4	4.1
Depreciation and amortization	1.6	0.5	0.5
Expenses	3,266.5	2,919.4	3,749.2
Operating income (loss)	$ 24.0	$ 56.1	$ (42.4)

Our Marketing business derives a majority of its operating income from selling natural gas received from producers on our Natural Gas segment pipeline assets to end users of the natural gas. A majority of the natural gas we purchase is produced in Texas markets where we previously had limited physical access to the primary interstate pipeline delivery points, or hubs, such as the Houston Ship Channel. As a result of the completed segments of our natural gas system expansions and other initiatives during 2007, our Marketing business now has access to several interstate natural gas pipelines, which it can use to transport natural gas to primary markets where it can be sold at more favorable prices. Prior to 2007, physical pipeline constraints often limited the ability of our Marketing business to transport the natural gas to these primary markets, which would more frequently require our Marketing business to transport natural gas to alternate market points with less favorable pricing.

Our Marketing business is exposed to commodity price fluctuations because the natural gas purchased by our Marketing business is generally priced using an index that is different from the pricing index at which the gas is sold. This price exposure arises from the relative difference in natural gas prices between the contracted index at which the natural gas is purchased and the index under which it is sold, otherwise known as the "spread." The spread can vary significantly due to local supply and demand factors. Wherever possible, this pricing exposure is economically hedged using derivative financial instruments. However, the structure of these economic hedges often precludes our use of hedge accounting under the requirements of SFAS No. 133, which can create volatility in the operating results of our Marketing segment.

In addition to the market access provided by our intrastate natural gas pipelines, our Marketing business also contracts for firm transportation capacity on third-party interstate and intrastate pipelines to allow access to additional markets. To offset the demand charges associated with these transportation agreements, we look for market conditions that allow us to lock in the price differential or spread between the pipeline receipt point and pipeline delivery point. This allows our Marketing business to lock in a fixed sales margin inclusive of pipeline demand charges. We accomplish this by transacting basis swaps between the index where the natural gas is purchased and the index where the natural gas is sold. By transacting a basis swap between those two indices, we can effectively lock in a margin on the combined natural gas purchase and the natural gas sale, mitigating the demand charges on these transportation agreements and limiting the Partnership's exposure to cash flow volatility that could arise in markets where the transporting the natural gas becomes uneconomical. However, the structure of these transactions precludes our use of hedge accounting under the requirements of SFAS No. 133, which can create volatility in the operating results of our Marketing segment.

In addition to natural gas basis swaps, we contract for storage to assist with balancing natural gas supply and end use market sales. In order to mitigate the absolute price differential between the cost of injected natural gas and withdrawn natural gas, as well as storage fees, the injection and withdrawal price differential, or "spread," is hedged by buying fixed price swaps for the forecasted injection periods and selling fixed price swaps for the forecasted withdrawal periods. When the injection and withdrawal spread increases or decreases in value as a result of market price movements, we can earn additional profit through the optimization of those hedges in both the forward and daily markets. Although all of these hedge strategies are sound economic hedging techniques, these types of financial transactions do not qualify for hedge accounting under the SFAS No. 133 guidelines. As such, the non-qualified hedges are accounted for on a mark-to-market basis, and the periodic change in their market value, although non-cash, will impact our operating results.

Natural gas purchased and sold by our Marketing segment is priced at a published daily or monthly price index. Sales to wholesale customers typically incorporate a premium for managing their transmission and balancing requirements. Higher premiums and associated margins result from transactions that involve smaller volumes or that offer greater service flexibility for wholesale customers. At their request, we will enter into long-term, fixed-price purchase or sales contracts with our customers and generally will enter into offsetting hedged positions under the same or similar terms.

Marketing pays third-party storage facilities and pipelines for the right to store and transport natural gas for various periods of time. These contracts may be denoted as firm storage, interruptible storage, or parking and lending services. These various contract structures are used to mitigate risk associated with sales and purchase contracts, and to take advantage of price differential opportunities.

Year ended December 31, 2007 compared with year ended December 31, 2006

Our Marketing business has benefited from the increased access to preferred natural gas markets resulting from our natural gas system expansions and other initiatives. Although the operating income of our Marketing segment for the year ended December 31, 2007 of $24.0 million is $32.1 million lower than the $56.1 million for the year ended December 31, 2006, the change is primarily due to the $68.3 million decrease in unrealized, non-cash mark-to-market gains associated with our derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133. For the year ended December 31, 2007, we recorded $3.8 million of unrealized mark-to-market losses from our derivative activities as compared with $64.5 million of unrealized mark-to-market gains for the year ended December 31, 2006. The unrealized, mark-to-market losses for the year ended December 31, 2007, are the result of modest increases in the forward and daily market prices of natural gas from December 31, 2006. During the year ended December 31, 2006, declines in the forward and daily market prices of natural gas from the historically high prices existing at December 31, 2005 produced significant unrealized mark-to-market gains in our portfolio of derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133. We expect the unrealized mark-to-market gains and losses associated with our portfolio of derivative financial instruments to be offset when the related physical transactions are settled. Refer to the discussions included in Item 7A. Quantitative and Qualitative Disclosures About Market Risk and Note 14 to our Financial Statements beginning on page F-1 of this report).

The operating results of our Marketing business for the year ended December 31, 2007 also include gains of approximately $16.3 million that we realized upon the sale of natural gas inventory, including approximately $6.9 million of gains from the settlement of derivative financial instruments hedging our natural gas inventory. Partially offsetting these gains are non-cash charges of $4.3 million that we recorded to reduce the cost basis of our natural gas inventory to fair market value, which is $12.7 million less than the $17.0 million non-cash charges we recorded during the year ended December 31, 2006. The market price for natural gas in various storage locations may experience declines during the year from the prices at which the inventory was purchased. Due to our hedging structures, we expect that a majority of these charges will be offset by future financial transactions that will settle at the time the natural gas inventory is sold.

Year ended December 31, 2006 compared with year ended December 31, 2005

For the year ended December 31, 2006, the operating income of our Marketing segment increased $98.5 million to $56.1 million, from a loss of $42.4 million in 2005. The significant increase in the operating income of our Marketing segment for 2006 is primarily due to unrealized, non-cash, mark-to-market net gains of approximately $64.5 million compared with unrealized mark-to-market net losses of $50.3 million for 2005. These unrealized mark-to-market changes are associated with derivative financial instruments that do not qualify for hedge accounting treatment under SFAS No. 133. The unrealized, mark-to-market gains for 2006 are the result of a decline in the forward and daily market price of natural gas from the historically high prices experienced in 2005. Additionally, the basis between the index where the natural gas is purchased and the index where the natural gas is sold has declined in correlation with the decline in the forward market price of natural gas contributing to the unrealized, mark-to-market net gains for 2006.

The operating results of our Marketing segment for the year ended December 31, 2006, also include non-cash charges totaling $17.0 million attributable to reducing the cost basis of our natural gas inventory to fair market value. Natural gas prices as published by Platt's *Gas Daily* for Henry Hub were approximately $10.08 per MMBtu at December 31, 2005, which had declined to $5.64 per MMBtu at December 31, 2006. As a result of the decline in the price of natural gas from 2005 to 2006, we recorded charges totaling $17.0 million during 2006 to reduce the cost basis of our inventory to fair market value. Partially offsetting this charge are gains of approximately $3 million that we realized upon settlement of derivative financial instruments hedging our natural gas inventory for 2006. Due to our hedging structures, we expect that a majority of the lower of cost or market inventory charges will be offset by future financial and physical transactions that will settle at the time the natural gas inventory is sold.

Corporate

Year ended December 31, 2007 compared with year ended December 31, 2006

Interest expense was $99.8 million in 2007 compared with $110.5 million in 2006. The decrease is due to $36.7 million of additional interest capitalized on our construction projects during the year compared with same period of 2006, partially offset by higher average debt balances and weighted average interest rates. Capitalized interest was approximately $47.4 million on our construction projects for 2007 compared with $10.7 million capitalized in 2006. Our weighted average interest rate was approximately 6.11% for the year ended December 31, 2007, compared with approximately 5.82% during 2006. Our debt balances are higher as a result of the capital expenditures we made to expand our pipeline systems that were partially financed by additional borrowings.

We are not a taxable entity for U.S. federal income tax purposes or for the majority of states that impose an income tax. Our income tax expense of $5.1 million for the year ended December 31, 2007 results from the enactment, by the state of Texas, of a new state tax computed on our 2007 modified gross margin. No comparable tax existed during the year ended December 31, 2006. We determined this tax to be an income tax under the provisions of SFAS No. 109, *Accounting for Income Taxes* ("SFAS No. 109"). We computed our income tax expense for the year ended December 31, 2007 by applying a 0.57% apportioned state income tax rate to taxable margin, as defined in State of Texas statutes. Our income tax expense represents a 2% effective rate as applied to pretax book income.

In July 2007, the State of Michigan enacted substantial changes to its tax structure that become effective in 2008. The new system is comprised of two parts, a modified gross receipts tax at 1% and a 6.04% tax on income that will be levied on our Michigan operating activities. We determined that these taxes are income taxes under the provisions of SFAS No. 109. Our initial accounting for the enactment of this income tax did not materially affect our results of operation, financial position, or cash flows.

Year ended December 31, 2006 compared with year ended December 31, 2005

Interest expense was $110.5 million in 2006 compared with $107.7 million in 2005. The increase is the result of higher debt balances and weighted average interest rates, partially offset by approximately $10.7 million of interest capitalized on our construction projects for 2006 compared with $4.0 million capitalized in 2005. Our weighted average interest rate was approximately 5.82% for the year ended December 31, 2006, compared with approximately 5.78% during 2005. Our debt balances are higher at December 31, 2006 compared with December 31, 2005 as a result of the capital expenditures we have made to expand our existing systems to improve the service capabilities of our assets.

Included in other income for the year ended December 31, 2006, is approximately $4.5 million that we received as settlement for an insurance claim that we filed in connection with an interruption to the operations of our Lakehead system resulting from a fire that occurred at Suncor's upgrader site in January 2005.

LIQUIDITY AND CAPITAL RESOURCES

General

We believe that our ability to generate cash flow, in addition to our access to capital, is sufficient to meet the demands of our current and future operating and investment needs. Our primary cash requirements consist of normal operating expenses, capital expenditures for our expansion projects, enhancement and maintenance capital expenditures, debt service payments, distributions to our partners, acquisitions of new assets and businesses, and payments associated with our derivative transactions. Short-term cash requirements, such as operating expenses, maintenance capital expenditures, debt service payments and quarterly distributions to our partners, are expected to be funded by operating cash flows. Margin requirements associated with our derivative transactions are generally supported by letters of credit issued under our Credit Facility. We expect to fund long-term cash requirements for enhancements, expansion projects, and acquisitions from several sources, including cash flows from operating activities, borrowings under our commercial paper program, our Credit Facility, and the issuance of additional equity and debt securities. Our ability to complete future debt and equity offerings and the timing of any such offerings will depend on various factors, including prevailing market conditions, interest rates, our financial condition and credit rating at the time.

Our current business strategy emphasizes developing and expanding our existing Liquids and Natural Gas businesses with less focus on acquisitions. The internal growth projects we have planned for our Natural Gas business (see Natural Gas segment—Future Prospects), coupled with the Southern Access and Alberta Clipper projects on our Lakehead system (see Liquids segment—Future Prospects), will require significant expenditures of capital over the next several years. We expect to fund these expenditures from a balanced combination of additional issuances of partnership units and long-term debt. Our planned internal growth projects will require us to bear the cost of constructing these new assets before we will begin to realize a return on them.

Capital Resources

Equity Capital

Execution of our growth strategy and completion of our planned construction projects contemplate our accessing the public and private equity markets to obtain the capital necessary to fund these projects. During 2007, we obtained approximately $628.8 million of cash through equity issuances in both public and private transactions, including contributions of approximately $12.5 million from our general partner to maintain its two percent general partner interest. We used the proceeds from these offerings to repay outstanding commercial paper we had previously issued to finance a portion of our capital expansion projects and for use in future periods to fund additional expenditures under our capital expansion programs.

The following table presents historical information about offerings of our limited partner interests since January 2005:

Issuance Date	Class of Limited Partnership Interest	Number of units Issued	Offering Price per unit	Net Proceeds to the Partnership[(1)]	General Partner Contribution[(2)]	Net Proceeds Including General Partner Contribution
			(in millions, except units and per unit amounts)			
2007						
May	Class A	5,300,000	$ 58.000	$ 301.9	$ 6.1	$ 308.0
April	Class C	5,931,086	$ 53.113	314.4	6.4	320.8
		11,231,086		$ 616.3	12.5	$ 628.8
2006						
August	Class C	10,869,565	$ 46.000	$ 500.0	$ 10.2	$ 510.2
2005						
December	Class A	136,200	$ 46.000	$ 6.0	$ 0.2	$ 6.2
November	Class A	3,000,000	$ 46.000	132.1	2.8	134.9
February	Class A	2,506,500	$ 49.875	124.8	2.7	127.5
2005 Totals		5,642,700		$ 262.9	$ 5.7	$ 268.6

(1) Net of underwriters' fees and discounts, commissions and issuance expenses.

(2) Contributions made by the General Partner to maintain its 2% general partner interest.

Available Credit

A significant source of our liquidity is provided by the commercial paper market. We have a $600 million commercial paper program that is supported by our long-term Credit Facility, which we access primarily to provide temporary financing for our operating activities, capital expenditures and acquisitions, at rates that are generally lower than the rates available under our Credit Facility.

In the second half of 2007, the domestic credit markets were adversely affected by a sharp increase in the credit risk associated with U.S. asset-backed securities. Due to the increase in perceived risks in the credit markets, and the need of large financial institutions to preserve capital, investors turned to investments in U.S. government securities, while selling off more risky credit securities. The lack of demand for domestic credit instruments other than U.S. government securities have, at times, limited our ability to access the commercial paper markets. However, our Credit Facility, which supports our commercial paper program, continues to provide us with adequate liquidity to fund our growth projects.

In addition to our Credit Facility, we executed an unsecured revolving credit agreement with Enbridge U.S. Inc., a wholly-owned subsidiary of Enbridge Inc. (the "EUS Credit Agreement") in December 2007, which provides us with access to an additional $500 million of financing under substantially the same terms as our Credit Facility.

Although the U.S. credit markets remain volatile, we were able to successfully raise approximately $593 million during the second half of 2007 through the issuance of $200 million of our senior, unsecured zero coupon notes due 2022 (the "Zero Coupon Notes") and $400 million of our fixed/floating rate, unsecured, long-term junior subordinated notes due 2067. Both of these issuances are discussed below and in Note 9 to our consolidated financial statements included in Item 8. Financial Statements to this report on Form 10-K.

Outstanding Indebtedness

The following table presents the components of our outstanding indebtedness:

	December 31, 2007	December 31, 2006
	(in millions)	
Current maturities of long-term debt:		
Current portion of First Mortgage Notes	$ 31.0	$ 31.0
Note payable to affiliate	$ —	$ 136.2
Long-term debt:		
Commercial Paper	$ 268.5	$ 443.7
Credit Facility	400.0	—
Affiliate Credit Agreement	—	—
First Mortgage Notes	93.0	124.0
4.000% senior notes due 2009	200.0	200.0
7.900% senior notes due 2012(1)	100.0	100.0
4.750% senior notes due 2013	200.0	200.0
5.350% senior notes due 2014	200.0	200.0
5.875% senior notes due 2016	300.0	300.0
7.000% senior notes due 2018(1)	100.0	100.0
7.125% senior notes due 2028(1)	100.0	100.0
5.950% senior notes due 2033	200.0	200.0
6.300% senior notes due 2034	100.0	100.0
Senior, unsecured zero coupon notes due 2022	203.6	—
8.05% fixed/floating rate junior subordinated notes due 2067	400.0	—
Unamortized discount	(2.2)	(1.6)
Total long-term debt	$ 2,862.9	$ 2,066.1
Note payable to affiliate(2)	$ 130.0	$ —

(1) Debt of Enbridge Energy, Limited Partnership, one of our operating subsidiaries.

(2) Ranks subordinate to our Credit Facility and other senior indebtedness, and ranks equally with current and future Junior Notes.

Credit Facility

Our Credit Facility, as amended, is a revolving term facility that matures in April 2012. In April 2007, we entered into the Second Amended and Restated Credit Agreement which among other things increased the maximum principal amount of credit available to us at any one time from $1 billion to $1.25 billion and allows us to request increases in the maximum principal amount of credit available at any one time from $1.25 billion to $1.5 billion. We pay interest on the amounts outstanding at variable rates equal to a "Base Rate" or a "Eurodollar Rate" as defined in the Credit Facility. In the case of Eurodollar Rate loans, an additional margin is charged which varies depending on our credit rating and the amounts drawn under the facility. We are also charged a facility fee on the entire amount of the Credit Facility, regardless of the amount drawn, which also varies depending on our credit rating. We continue to use our Credit Facility to support our commercial paper program and provide short-term financing for our operations and capital expansion programs.

The amounts we can borrow under the terms of our Credit Facility are reduced by the principal amount of our commercial paper issuances and the balance of our letters of credit outstanding. At December 31, 2007, we had $400 million outstanding under our Credit Facility at a weighted average interest rate of 5.22% and letters of credit totaling $159.7 million. At December 31, 2007, we could borrow $420.3 million under the terms of our Credit Facility, determined as follows:

			2007
			(in millions)
Total credit available under Credit Facility		$	1,250.0
Less:	Amounts outstanding under Credit Facility		(400.0)
	Balance of letters of credit outstanding		(159.7)
	Principal amount of commercial paper issuances		(270.0)
Total amount we could borrow at December 31, 2007		$	420.3

Our Credit Facility contains restrictive covenants that require us to maintain a maximum leverage ratio of 5.50 to 1.0 for periods ending on or before March 31, 2009; a ratio of 5.25 to 1.0 thereafter, for periods ending on or before March 31, 2010; and a ratio of 5.00 to 1.0 for periods ending June 30, 2010 and following. At December 31, 2007, our leverage ratio was approximately 3.6. Our Credit facility also places limitations on the debt that our subsidiaries may incur directly. Accordingly, it is expected that we will provide debt financing to our subsidiaries as necessary.

Commercial Paper Program

At December 31, 2007, we had $270 million in principal amount of commercial paper outstanding, with unamortized discount of $1.5 million, at a weighted average interest rate of 5.36%, before the effect of our interest rate hedging activities. We had net repayments of approximately $171.5 million during 2007 under our commercial paper program, which include gross issuances of $5,172.7 million and gross repayments of $5,344.2 million. At December 31, 2007, we could issue an additional $330 million in principal amount under our commercial paper program.

First Mortgage Notes

The First Mortgage Notes are collateralized by a first mortgage on substantially all of the property, plant and equipment of Enbridge Energy, Limited Partnership, (the "OLP"), and are due and payable in equal annual installments of $31.0 million until their maturity in 2011. The Notes contain various restrictive covenants applicable to us, and restrictions on the incurrence of additional indebtedness by the OLP, including compliance with certain debt issuance tests. We were in compliance with these covenants at December 31, 2007. We believe these issuance tests will not negatively affect our ability to access the credit markets to finance future expansion projects. Under the First Mortgage Notes Agreements, we cannot make cash distributions more frequently than quarterly in an amount not to exceed Available Cash for the immediately preceding calendar quarter. If we repay the Notes prior to their stated maturities, the First Mortgage Note Agreements provide for the payment of a redemption premium by us.

Senior Notes

All of our Senior Notes represent our unsecured obligations that rank equally in right of payment with all of our existing and future unsecured and unsubordinated indebtedness. Our Senior Notes are structurally subordinated to all existing and future indebtedness and other liabilities, including trade payables of our subsidiaries and the $300 million of senior notes issued by the OLP (the "OLP Notes"). The borrowings under our Senior Notes are non-recourse to our General Partner and Enbridge Management. All of our Senior Notes pay interest semi-annually and have varying maturities and terms as presented in the table above. Our Senior Notes do not contain any covenants restricting us from issuing additional indebtedness. Our Senior Notes are subject to make-whole redemption rights and were issued under an indenture containing certain covenants that restrict our ability, with certain exceptions, to sell, convey, transfer, lease or otherwise dispose of all or substantially all of our assets, except in accordance with our indenture agreement. We were in compliance with these covenants at December 31, 2007.

The OLP, our operating subsidiary that owns the Lakehead system, has $300 million of senior notes outstanding representing unsecured obligations that are structurally senior to our Senior Notes. All of the OLP Notes pay interest semi-annually and have varying maturities and terms as set forth in the table above. The OLP Notes do not contain any covenants restricting us from issuing additional indebtedness by the OLP. The OLP Notes are subject to make-whole redemption rights and were issued under an indenture ("the OLP Indenture") containing certain covenants that restrict our ability, with certain exceptions, to sell, convey, transfer, lease or otherwise dispose of all or substantially all of our assets, except in accordance with the OLP Indenture. We were in compliance with these covenants at December 31, 2007.

In August 2007, we received net proceeds of approximately $200 million from a private placement of our senior, unsecured zero coupon notes due 2022 (the "Zero Coupon Notes"), which at maturity will be payable in the aggregate principal amount of $442 million. We initially recorded the Zero Coupon Notes in long-term debt at the amount of proceeds we received from the private placement, which we refer to as the issue price. The carrying amount at December 31, 2007 includes $3.6 million associated with the accretion of interest we recognized as interest expense during the period. The Zero Coupon Notes are scheduled to mature on August 28, 2022, although they may be called by the note holders prior to the scheduled maturity date on August 28 of any year commencing on August 28, 2009, at a price equal to the then accreted value of the called Zero Coupon Notes. The Zero Coupon Notes have a yield of 5.36% on a semi-annual compound basis and rank equally in right of payment to all of our existing and future senior indebtedness, as set forth in our senior indenture. We used the net proceeds from this private placement to repay a portion of our outstanding commercial paper and Credit Facility borrowings that we had previously incurred to fund a portion of our capital expansion projects.

In December 2006, we issued $300 million in aggregate principal amount of our 5.875% Senior Notes due 2016 in a public offering, from which we received proceeds of $297.6 million, after payment of underwriting discounts and commissions and estimated offering expenses. We used the proceeds to repay a portion of our outstanding commercial paper and to finance a portion of our capital expansion projects.

Junior Subordinated Notes

In September 2007, we issued and sold $400 million in principal amount of our 8.05% fixed/floating rate, unsecured, long-term junior subordinated notes due 2067, which we refer to as the Junior Notes. We received net proceeds of approximately $393.0 million, after payment of underwriting discounts, commissions and offering expenses, which we used to temporarily reduce a portion of our outstanding commercial paper and Credit Facility borrowings that we incurred to finance a portion of our capital expansion projects. The Junior Notes are subordinate in right of payment to all of our existing and future senior indebtedness, as defined in the related indenture.

Indebtedness to Affiliates

Hungary Note Payable

As of December 31, 2007 and 2006, we had $130.0 million and $136.2 million, respectively, in amounts outstanding under notes payable to Enbridge Hungary Ltd., an affiliate of our general partner, which we refer to as the Hungary Note. In December 2007, we repaid $145.0 million of the original Hungary Note, including $8.8 million of accrued interest, with proceeds we received from entering into a new Hungary Note agreement with substantially the same terms and approximately $15 million from our existing cash. The new Hungary Note bears interest at a fixed rate of 8.4% per annum that is payable semi-annually in June and December of each year through its maturity in December 2017. Similar to the old Hungary Note, the new note allows us the option of paying accrued and unpaid interest in the form of additional indebtedness by increasing the principal balance of the note for the amounts due. Consistent with the original Hungary Note, the new Hungary Note has cross-default provisions that are triggered by events of default under our First Mortgage Notes or defaults under our Credit Facility. The new Hungary Note is subordinate to our Credit Facility and other senior indebtedness, and ranks equally with current and future Junior Notes. We entered into the original Hungary Note agreement in connection with our acquisition of the Midcoast system in October 2002. For the year ended December 31, 2006, we converted interest payable in the amount of $4.4 million into debt by increasing the principal balance of the original Hungary Note.

EUS Credit Agreement

In December 2007, we entered an unsecured revolving credit agreement with Enbridge (U.S.) Inc., a wholly-owned subsidiary of Enbridge. Enbridge is the indirect owner of Enbridge Energy Company, Inc., our general partner. The EUS Credit Agreement provides for a maximum principal amount of credit available to us at any one time of $500 million for a three-year term that matures in December 2010. The EUS Credit Agreement also includes financial covenants that are consistent with those in our Second Amended and Restated Credit Agreement as discussed above. Amounts borrowed under the EUS Credit Agreement bear interest at rates that are consistent with the interest rates set forth in our Second Amended and Restated Credit Agreement. At December 31, 2007, we had no balances outstanding under the EUS Credit Agreement and the full amount remains available for our use.

Credit Ratings

The following table reflects the ratings that have been assigned to our debt and the debt of our wholly-owned subsidiary, Enbridge Energy, Limited Partnership at December 31, 2007:

	Standard & Poor's	Moody's	Dominion Bond Rating Service
Enbridge Energy Partners, L.P.			
Outlook	Stable	Negative	Stable
Corporate	BBB	Baa2	BBB
Commercial Paper	A-2	P-2	R-2(middle)
Medium Term Notes & Unsecured Debentures	BBB	Baa2	BBB
Junior subordinated debt	BB+	Baa3	BB(high)
Enbridge Energy, Limited Partnership			
Outlook	Stable	Negative	NR
Senior secured	BBB+	Baa1	NR
Senior unsecured	BBB	Baa1	NR

NR—No rating is available

Moody's continues to maintain our Baa2 rating with a negative outlook. This reflects Moody's view that our financial profile is weaker than those of our similarly rated peers. However, Moody's believes that this weaker financial profile is offset to a degree by our low business risk profile that stems from our highly regulated and/or contracted liquids and natural gas systems and our strategy of hedging a significant portion of our commodity exposure. While our substantial organic growth capital expenditure program will place our financial profile under near term pressure until these projects are commissioned and increase our reliance on the capital markets, Moody's believes that completion of our organic growth projects should contribute to a further reduction in our overall business risk profile and that the cash flow generated by these projects as they are commissioned will strengthen our financial profile. Following the successful execution of both the construction and financing of these growth projects, an improved rating outlook by Moody's is possible.

Summary of Obligations and Commitments

The following table summarizes the principal amount of our obligations and commitments at December 31, 2007:

Future Minimum Commitments	2008	2009	2010	2011	2012	Thereafter	Total
				(in millions)			
Long-term debt and notes payable to affiliates	$ 31.0	$ 434.6	$ 31.0	$ 31.0	$ 770.0	$ 1,730.0	$ 3,027.6
Purchase commitments[1]	305.4	—	—	—	—	—	305.4
Power commitments[2]	2.9	0.2	0.2	—	—	—	3.3
Other operating leases	11.9	8.9	2.7	0.4	—	0.1	24.0
Right-of-way[3]	1.7	1.7	1.7	1.7	1.7	41.0	49.5
Product purchase obligations[4]	55.7	38.5	34.5	32.7	31.0	84.3	276.7
Service contract obligations[5]	36.0	28.8	25.6	18.6	7.3	0.5	116.8
Total	$ 444.6	$ 512.7	$ 95.7	$ 84.4	$ 810.0	$ 1,855.9	$ 3,803.3

(1) Represents commitments to purchase materials, primarily pipe from third-party suppliers in connection with our expansion projects.

(2) Represents commitments to purchase power in connection with our Liquids segment.

(3) Right-of-way payments are estimated to be approximately $1.7 million per year for the remaining life of all pipeline systems, which has been assumed to be 25 years for purposes of calculating the amount of future minimum commitments beyond 2012.

(4) We have long-term product purchase obligations with several third-party suppliers to acquire natural gas and NGLs at prices approximating market at the time of delivery.

(5) The service contract obligations represent the minimum payment amounts for firm transportation and storage capacity we have reserved on third-party pipelines and storage facilities.

Cash Requirements for Future Growth

Capital Spending

We expect to make significant expenditures during the next three years for the construction of additional natural gas and crude oil transportation infrastructure. Anticipated growth in Western Canadian oil sands production and the need to reach newer markets has prompted the Southern Access, Alberta Clipper and related projects associated with our liquid systems. In 2008, we expect to spend approximately $1.4 billion on these and other projects with the expectation of realizing additional cash flows as projects are completed and placed into service. At December 31, 2007, we had approximately $305.4 million in outstanding purchase commitments attributable to capital projects for the construction of assets that will be recorded as property, plant and equipment during 2008.

Forecasted Expenditures

We categorize our capital expenditures as either core maintenance or enhancement expenditures. Core maintenance expenditures are those expenditures that are necessary to maintain the service capability of our existing assets and includes the replacement of system components and equipment which is worn, obsolete or completing its useful life. Enhancement expenditures include our capital expansion projects and other projects that improve the service capability of our existing assets, extend asset useful lives, increase capacities from existing levels, reduce costs or enhance revenues, and enable us to respond to governmental regulations and developing industry standards.

We estimate our forecasted expenditures based upon our strategic operating and growth plans, which are also dependent upon our ability to produce or otherwise obtain the capital necessary to accomplish our growth objectives. The following table sets forth our estimates of capital required for system enhancement and core maintenance expenditures through December 31, 2008. Although we anticipate making the expenditures in 2008, these estimates may change due to factors beyond our control, including weather-related issues, construction timing, changes in supplier prices or poor economic conditions. Additionally, our estimates may also change as a result of decisions made at a later date to revise the scope of a project or undertake a particular capital program. We made capital expenditures of $1,980.2 million, including $59.8 million on core maintenance activities, for the year ended December 31, 2007.

For the full year ending December 31, 2008, we anticipate our capital expenditures to approximate the following:

	Total Forecasted Expenditures
	(in billions)
Other system enhancements	$ 0.5
Core maintenance activities	0.1
Southern Access expansion	0.6
Alberta Clipper	0.2
	$ 1.4

Major Construction Projects

The following table includes our active major construction projects and additional information regarding our projected cost, actual expenditures through December 31, 2007, the incremental capacity that will or has become available upon completion of the project and the periods we expect to complete the construction. The projected amounts included in this table may change due to modifications of the scope of the project, increases in materials and construction costs and other factors that are outside of our direct control.

	Capital Expenditures		Estimated Incremental Capacity			
	Estimated Total Cost	Actual Expenditures Inception through December 31, 2007	Storage	Oil	Natural Gas	Expected Completion
	(in billions)		(KBbl)	(Kbpd)	(MMcf/d)	
Southern Access expansion (Lakehead)	$ 2.1	$ 1.1	—	400	—	2009
Clarity (East Texas)	0.6	0.6	—	—	700	Early 2008
Alberta Clipper	1.2	—	—	450	—	Mid-2010
North Dakota phase 6 expansion	0.2	—	—	51	—	Early 2010
Griffith and Superior storage tanks	0.1	—	1,220	—	—	Mid-2008
Total	$ 4.2	$ 1.7	1,220	901	700	

Including major expansion projects and excluding acquisitions, ongoing capital expenditures are expected to be significant over the next three years due to our Southern Access expansion and Alberta Clipper projects. Core maintenance capital is also anticipated to increase over that period of time due to growth in our pipeline systems and aging of infrastructure.

We anticipate funding the system enhancement capital expenditures temporarily through the issuance of commercial paper and borrowing under the terms of our Credit Facility, with permanent debt and equity funding being obtained when appropriate. Core maintenance expenditures are expected to be funded by operating cash flows.

We expect to incur continuing annual capital and operating expenditures for pipeline integrity measures to ensure both regulatory compliance and to maintain the overall integrity of our pipeline systems. Expenditure levels have continued to increase as pipelines age and require higher levels of inspection or maintenance; however, these are viewed to be consistent with industry trends.

The following table presents major construction projects that we have completed during 2007 and additional information regarding the estimated cost, actual expenditures through December 31, 2007, the incremental capacity that has become available upon completion of the project and the periods construction was completed.

	Capital Expenditures		Estimated Incremental Capacity			
	Estimated Total Cost	Actual Expenditures Inception through December 31, 2007	Storage	Oil	Natural Gas	Period Completed
	(in billions)		(KBbl)	(Kbpd)	(MMcf/d)	
North Dakota system expansion	0.1	0.1	—	30	—	November 2007
Cushing terminal storage tanks	0.1	0.1	4,970	—	—	Throughout 2007
Processing and treating plant expansions	0.3	0.3	—	—	1,130	Various
Total	$ 0.5	$ 0.5	4,970	30	1,130	

Acquisitions

We continue to assess ways to generate value for our unitholders, including reviewing opportunities that may lead to acquisitions, dispositions or other strategic transactions, some of which may be material. We evaluate opportunities against operational, strategic and financial benchmarks before pursuing. The market for acquiring energy transportation assets is active and competition among prospective acquirers of assets has been significant. While we remain committed to making accretive acquisitions in or near areas where we already operate or have a competitive advantage, we will continue to focus our efforts on development of our existing pipeline systems. Additionally, we may pursue opportunities to divest of any non-strategic assets as conditions warrant.

We expect that the funds needed to achieve growth through acquisitions will be obtained through issuances of commercial paper, borrowings under the terms of our Credit Facility, term debt and issuances of additional partnership interests.

Derivative Activities

We use derivative financial instruments (e.g., futures, forwards, swaps, options and other financial instruments with similar characteristics) to mitigate the volatility of our cash flows and manage the purchase and sales prices of our commodities. Based on our risk management policies, all of our derivative financial instruments are employed in connection with an underlying asset, liability or anticipated transaction and are not entered into with the objective of speculating on commodity prices.

The following table provides summarized information about the timing and expected settlement amounts of our outstanding commodity derivative financial instruments based upon the market values at December 31, 2007 for each of the indicated calendar years:

	Notional	2008	2009	2010	2011	2012
			($ in millions)			
Swaps						
Natural gas[1]	328,985,388	$ (32.9)	$ (35.6)	$ (32.8)	$ (30.8)	$ (5.9)
NGL[2]	10,163,878	(98.9)	(43.6)	(13.8)	(4.3)	—
Crude[2]	1,411,221	(17.7)	(7.2)	(4.4)	(3.4)	(1.9)
Options—calls						
Natural gas[1]	1,461,000	(1.3)	(1.5)	(1.4)	(1.4)	—
Options—puts						
Natural gas[1]	1,401,000	—	—	—	—	—
NGL[2]	763,403	0.1	0.6	—	—	—
Totals		$ (150.7)	$ (87.3)	$ (52.4)	$ (39.9)	$ (7.8)

(1) Notional amounts for natural gas are recorded in millions of British thermal units ("MMBtu").

(2) Notional amounts for NGL and Crude are recorded in Barrels ("Bbl").

Operating Activities

Net cash provided by our operating activities was $463.4 million in 2007 compared with $321.6 million in 2006. The improved operating cash flow is primarily attributable to sales of inventory during 2007 that we did not make in 2006 and other changes in working capital accounts related to general timing differences between the collection on and payment of our current and related party accounts.

Investing Activities

Net cash used in our investing activities during the year ended December 31, 2007 was $1,765 million, an increase of $898 million from the $867 million used during the same period of 2006. The increase is primarily attributable to the $1,062.6 million increase in our investments in property, plant and equipment during the year ended December 31, 2007, over the amount spent during the year ended December 31, 2006, partially offset by $133 million of proceeds we received from the sale of our KPC system. The increase in our capital expenditures during the year ended December 31, 2007 is directly attributable to our previously described expansion projects. We expect that cash flows used in our investing activities will remain at high levels throughout the periods we are performing extensive expansions to our Lakehead and East Texas systems.

Financing Activities

Net cash provided by financing activities during the year ended December 31, 2007 was $1,167.5 million, an increase of $527.3 million from the $640.2 million generated during the year ended December 31, 2006. We increased the level of our financing activities during 2007 to obtain permanent financing for our capital expansion projects. The permanent financing we completed during the year ended December 31, 2007 includes the following:

- We issued and sold in September 2007, $400.0 million of our Junior Notes for net proceeds of $393.0 million, which we used to partially reduce issuances of commercial paper and borrowings under our Credit Facility;

- We issued and sold in August 2007, $200.0 million in principal amount of our Zero Coupon Notes for net proceeds of $199.8 million, which we used to partially reduce issuances of commercial paper and borrowings under our credit facility.

- In May 2007, we issued and sold 5.3 million of our Class A common units for net proceeds of $308.0 million including a $6.1 million contribution from our general partner to maintain its 2 percent general partner interest.

- In April 2007, we issued and sold approximately 5.9 million of our Class C units in a private placement for net proceeds of approximately $320.8 million, including a $6.4 million contribution from our general partner to maintain its 2 percent general partner interest.

Also contributing to the increase in our financing activities for the year ended December 31, 2007 are net Credit facility borrowings of $400.0 million, which include gross borrowings of $740.0 million and gross repayments of $340.0 million. We also had net repayments of commercial paper of $171.5 million, which include gross issuances of $5,172.7 million and gross repayments of $5,344.2 million.

During the year ended December 31, 2007, cash distributions to our partners increased to $245.4 million from $227.4 million in the same period of 2006 due to:

- An increase in the number of units outstanding;

- An increase in the quarterly distribution rate per unit from $0.925 to $0.950 for the distribution paid in November 2007; and

- An increase in the general partner incentive distributions, as a result of the increased distributions to our limited partners.

Cash Distributions

We make quarterly distributions to our General Partner and the holders of our limited partner units in an amount equal to our "available cash." As defined in our partnership agreement, "available cash" represents for any calendar quarter, the sum of all of our cash receipts plus net reductions to reserves less all of our cash disbursements and net changes to reserves. We retain reserves to provide for the proper conduct of our business, to stabilize distributions to our unitholders and the General Partner and, as necessary, to comply with the terms of any of our agreements or obligations. Enbridge Management, as the delegate of the General Partner under a delegation of control agreement, computes the amount of our available cash.

As the owner of our i-units, Enbridge Management does not receive distributions in cash. Instead, each time that we make a cash distribution to the General Partner and the holders of our Class A and Class B common units, the number of i-units owned by Enbridge Management and the percentage of total units in us owned by Enbridge Management increases automatically under the provisions of our partnership agreement with the result that the number of i-units owned by Enbridge Management will equal the sum of Enbridge Management's shares that are then outstanding. The amount of this increase in i-units is determined by dividing the cash amount distributed per limited partner unit by the average price of one of Enbridge Management's listed shares on the NYSE for the 10-trading day period immediately preceding the ex-dividend date for Enbridge Management's shares multiplied by the number of shares outstanding on the record date. The cash equivalent amount of the additional i-units is treated as if it had actually been distributed for purposes of determining the distributions to be made to the General Partner.

Until August 15, 2009, in lieu of cash distributions, the holders of our Class C units will receive quarterly distributions of additional Class C units with a value equal to the quarterly cash distributions we pay to the holders of our Class A and Class B common units, which we collectively refer to as common units. The number of additional Class C units we will issue is determined by dividing the quarterly cash distribution per unit we pay on our common units by the average market price of a Class A common unit as listed on the New York Stock Exchange for the 10-trading day period immediately preceding the ex-dividend date for our Class A common units multiplied by the number of Class C units outstanding on the record date. As a result, the number of Class C units and the percentage of our total units owned by holders of the Class C units will increase automatically under the provisions of our partnership agreement. The cash equivalent amount of the additional Class C units is treated as if it had actually been distributed for purposes of determining the distributions to be made to the General Partner.

After August 15, 2009, the holders of our Class C units will receive quarterly cash distributions equal to those paid to the holders of our common units. Subject to the approval of holders of our outstanding units in accordance with the then-existing requirements of the principal national securities exchange on which the Class A common units are listed, the Class C units will convert into Class A common units on a one-for-one basis. If our unitholders do not approve the conversion, the holders of our Class C units will receive quarterly cash distributions equal to 115 percent of those paid to the holders of our common units. Prior to conversion, holders of our Class C units will not be entitled to receive any quarterly cash distribution until the holders of our common units have received a minimum quarterly cash distribution of $0.59 per common unit. As of May 2007, the NYSE no longer requires unitholder approval to convert the Class C units to Class A common units.

For purposes of calculating the sum of all distributions of available cash, the cash equivalent amount of the additional i-units and Class C units that are issued when a distribution of cash is made to the General Partner and owners of common units is treated as distribution of available cash, even though the i-unit holder and holders of our Class C units will not receive cash. We retain the cash for use in our operations to finance a portion of our capital expansion projects. During 2007, we distributed a total of 889,938 i-units through quarterly distributions to Enbridge Management, compared with 969,200 in 2006. Additionally, we distributed a total of 1,072,423 Class C units to the holders of our Class C units. We retained $107.5 million in 2007 related to the i-unit and Class C unit distributions, compared with $54.7 million in 2006.

Our current annual cash distribution rate is $3.80 per unit, or $0.950 per quarter compared with $3.725 for the year ended December 31, 2007. We expect that all cash distributions will be paid out of operating cash flows over the long term; however, from time to time, we may temporarily borrow under our Credit Facility or issue additional commercial paper for the purpose of paying cash distributions until we realize the full impact of assets being developed on operations.

Off-Balance Sheet Arrangements

We have no significant off-balance sheet arrangements.

Subsequent Events

Distribution to Partners

On January 28, 2008, the board of directors of Enbridge Management declared a distribution payable to our partners on February 14, 2008. The distribution was paid to unitholders of record as of February 6, 2008, of our available cash of $96.7 million at December 31, 2007, or $0.950 per limited partner unit. Of this distribution, $66.0 million was paid in cash, $12.9 million was distributed in i-units to our i-unitholder, $17.2 million was distributed in Class C units to the holders of our Class C units and $0.6 million was retained from the General Partner in respect of the i-unit and Class C unit distributions to maintain its two percent general partner interest.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Our selection and application of accounting policies is an important process that has developed as our business activities have evolved and as new accounting pronouncements have been issued. Accounting decisions generally involve an interpretation of existing accounting principles and the use of judgment in applying those principles to the specific circumstances existing in our business. We make every effort to comply with all applicable accounting principles and believe the proper implementation and consistent application of these principles is critical. However, not all situations we encounter are specifically addressed in the accounting literature. In such cases, we must use our best judgment to implement accounting policies that clearly and accurately present the substance of these situations. We accomplish this by analyzing similar situations and the accounting guidance governing them and consulting with experts about the appropriate interpretation and application of the accounting literature to these situations.

In addition to the above, certain amounts included in or affecting our consolidated financial statements and related disclosures must be estimated, requiring us to make certain assumptions with respect to values or conditions that cannot be known with certainty at the time the consolidated financial statements are prepared. These estimates affect the reported amounts of assets, liabilities, revenues, expenses and related disclosures with respect to contingent assets and liabilities. The basis for our estimates is historical experience, consultation with experts and other sources we believe to be reliable. While we believe our estimates are appropriate, actual results can and often do differ from these estimates. Any effect on our business, financial position, results of operations and cash flows resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known.

We believe our critical accounting policies and estimates discussed in the following paragraphs address the more significant judgments and estimates we use in the preparation of our consolidated financial statements. Each of these areas involves complex situations and a high degree of judgment either in the application and interpretation of existing accounting literature or in the development of estimates that affect our consolidated financial statements. Our management has discussed the development and selection of the critical accounting policies and estimates related to the reported amounts of assets, liabilities, revenues and expenses and disclosure of contingent liabilities with the Audit, Finance & Risk Committee of Enbridge Management's board of directors.

Revenue Recognition and the Estimation of Revenues and Cost of Natural Gas

In general, we recognize revenue when delivery has occurred or services have been rendered, pricing is determinable and collectibility is reasonably assured. For our natural gas and marketing businesses, we must estimate our current month revenue and cost of natural gas to permit the timely preparation of our consolidated financial statements. We generally cannot compile actual billing information nor obtain actual vendor invoices within a timeframe that would permit the recording of this actual data prior to preparation of the consolidated financial statements. As a result, we record an estimate each month for our operating revenues and cost of natural gas based on the best available volume and price data for natural gas delivered and received, along with a true-up of the prior month's estimate to equal the prior month's actual data. As a result, there is one month of estimated data recorded in our operating revenues and cost of natural gas for each period reported. We believe that the assumptions underlying these estimates will not be significantly different from the actual amounts due to the routine nature of these estimates and the stability of our processes.

Capitalization Policies, Depreciation Methods and Impairment of Property, Plant and Equipment

We capitalize expenditures related to property, plant and equipment, subject to a minimum rule, that have a useful life greater than one year for (1) assets purchased or constructed; (2) existing assets that are replaced, improved, or the useful lives have been extended; or (3) all land, regardless of cost. Acquisitions of new assets, additions, replacements and improvements (other than land) costing less than the minimum rule in addition to maintenance and repair costs are expensed as incurred.

During construction, we capitalize direct costs, such as labor and materials, and other costs, such as direct overhead and interest at our weighted average cost of debt, and, in our regulated businesses that apply the provisions of Statement of Financial Accounting Standards No. 71, *Accounting for the Effects of Certain Types of Regulation,* or SFAS No. 71, an equity return component.

We categorize our capital expenditures as either core maintenance or enhancement expenditures. Core maintenance expenditures are necessary to maintain the service capability of our existing assets and include the replacement of system components and equipment that are worn, obsolete or near the end of their useful lives. Examples of core maintenance expenditures include valve automation programs, cathodic protection, zero-hour compression overhauls and electrical switchgear replacement programs. Enhancement expenditures improve the service capability of our existing assets, extend asset useful lives, increase capacities from existing levels, reduce costs or enhance revenues, and enable us to respond to governmental regulations and developing industry standards. Examples of enhancement expenditures include costs associated with installation of seals, liners and other equipment to reduce the risk of environmental contamination from crude oil storage tanks, costs of sleeving a major segment of the pipeline system following an integrity tool run, natural gas or crude oil well-connects, natural gas plants and pipeline construction and expansion.

Regulatory guidance issued by the FERC requires us to expense certain costs associated with implementing the pipeline integrity management requirements of the U.S. Department of Transportation's Office of Pipeline Safety. Under this guidance, beginning in January 2006, costs to 1) prepare a plan to implement the program, 2) identify high consequence areas, 3) develop and maintain a record keeping system and 4) inspect, test and report on the condition of affected pipeline segments to determine the need for repairs or replacements, are required to be expensed. We adopted this guidance prospectively in January 2006 for all our pipeline systems. Costs of modifying pipelines to permit in-line inspections, certain costs associated with developing or enhancing computer software and costs associated with remedial mitigation actions to correct an identified condition continue to be capitalized. We have historically capitalized initial in-line inspection programs, crack detection tool runs and hydrostatic testing costs conducted for the purposes of detecting manufacturing or construction defects. Beginning January 2006, costs of this nature are expensed as incurred which is consistent with industry practice and the regulatory guidance issued by the FERC. However, we continue to capitalize initial construction hydrostatic testing cost and subsequent hydrostatic testing programs conducted for the purpose of increasing pipeline capacity in accordance with our capitalization policies. Also capitalized are certain costs such as sleeving or recoating existing pipelines, unless the expenditures are incurred as a single event and not part of a major program, in which case we expense these costs as incurred. Our adoption of the regulatory guidance did not significantly affect our financial position, results of operations or cash flows.

We record property, plant and equipment at its original cost, which we depreciate on a straight-line basis over the lesser of their estimated useful lives or the estimated remaining lives of the crude oil or natural gas production in the basins the assets serve. Our determination of the useful lives of property, plant and equipment requires us to make various assumptions, including the supply of and demand for hydrocarbons in the markets served by our assets, normal wear and tear of the facilities, and the extent and frequency of maintenance programs. We routinely utilize consultants and other experts to assist us in assessing the remaining lives of the crude oil or natural gas production in the basins we serve.

We record depreciation using the group method of depreciation which is commonly used by pipelines, utilities and similar entities. Under the group method, for all segments, upon the disposition of property, plant and equipment, the cost less net proceeds is normally charged to accumulated depreciation and no gain or loss on disposal is recognized. However, when a separately identifiable group of assets, such as a stand-alone pipeline system is sold, we will recognize a gain or loss in our consolidated statements of income for the difference between the cash received and the net book value of the assets sold. Changes in any of our assumptions may alter the rate at which we recognize depreciation in our consolidated financial statements. At regular intervals, we retain the services of independent consultants to assist us with assessing the reasonableness of the useful lives we have established for the property, plant and equipment of our major systems. Based on the results of these regular assessments we may make modifications to the assumptions we use to determine our depreciation rates.

We evaluate the recoverability of our property, plant and equipment when events or circumstances such as economic obsolescence, the business climate, legal and other factors indicate we may not recover the carrying amount of the assets. We continually monitor our businesses and the market and business environments to identify indicators that may suggest an asset may not be recoverable. We evaluate the asset for recoverability by estimating the undiscounted future cash flows expected to be derived from operating the asset. These cash flow estimates require us to make projections and assumptions for many years into the future for pricing, demand, competition, operating cost and other factors. We recognize an impairment loss when the carrying amount of the asset exceeds its fair value as determined by quoted market prices in active markets or present value techniques if quotes are unavailable. The determination of the fair value using present value techniques requires us to make projections and assumptions regarding the probability of a range of outcomes and the rates of interest used in the present value calculations. Any changes we make to these projections and assumptions could result in significant revisions to our evaluation of recoverability of our property, plant and equipment and the recognition of an impairment loss in our consolidated statements of income.

Assessment of Recoverability of Goodwill and Intangibles

Goodwill represents the excess of the purchase price over the fair value of net assets acquired in a business combination. Goodwill is not amortized, but is tested for impairment annually based on the carrying values as of the end of the second quarter, or more frequently if impairment indicators arise that suggest the carrying value of goodwill may not be recovered. Impairment occurs when the carrying amount of a reporting unit exceeds its fair value. At the time we determine that impairment has occurred, the carrying value of the goodwill is written down to its fair value. To estimate the fair value of the reporting units, we make estimates and judgments about future cash flows, as well as revenue, cost of sales, operating expenses, capital expenditures and net working capital based on assumptions that are consistent with our most recent five-year plan, which we use to manage the business.

Preparation of forecast information for use in our five-year plan involves significant judgment. Actual results can, and often do, differ from the projections and assumptions we make in preparing these forecasts. These changes can have a negative impact on our estimates of impairment, which could result in charges to income. In addition, further changes in the economic and business environment can affect our original and ongoing assessments of potential impairment.

Other intangible assets consist of customer contracts for the purchase and sale of natural gas, and natural gas supply opportunities, which we amortize on a straight-line basis over the weighted average useful life of the underlying assets, which is the period over which the asset is expected to contribute directly or indirectly to our future cash flows.

We evaluate the carrying value of the intangible assets whenever certain events or changes in circumstances indicate that the carrying amount of these assets may not be recoverable. In assessing the recoverability of intangibles, we compare the carrying value to the undiscounted future cash flows the intangibles are expected to generate. If the total of the undiscounted future cash flows is less than the carrying amount of the intangibles, the intangibles are written down to their fair value. If there are changes to any of our estimates and assumptions, actual results may differ.

Asset Retirement Obligations

We record a liability for the fair value of our asset retirement obligations, or ARO, on a discounted basis, in the period in which the liability is incurred. Typically we record an ARO at the time the assets are installed or acquired, if a reasonable estimate of fair value can be made. In connection with establishing an

ARO, we capitalize the costs as part of the carrying value of the related assets. We recognize an ongoing expense for the interest component of the liability as part of depreciation expense resulting from changes in the value of the ARO due to the passage of time. We depreciate the initial capitalized costs over the useful lives of the related assets. We extinguish the liabilities for asset retirement obligations when assets are taken out of service or otherwise abandoned.

The provisions of Financial Accounting Standards Board ("FASB") Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations, an interpretation of FASB Statement No. 143* ("FIN 47") require us to recognize a liability and related asset, consistent with SFAS No. 143, for the fair value of conditional asset retirement obligations that we can reasonably estimate. FIN 47 also provides specific guidance regarding when an asset retirement obligation is reasonably estimable including when sufficient information is available to apply an expected present value technique. Our implementation of FIN 47 did not have a material impact effect on our consolidated financial statements.

We have legal obligations requiring us to decommission our offshore pipeline systems at retirement. In certain rate jurisdictions, we are permitted to include annual charges for removal costs in the regulated cost of service rates we charge our customers. Additionally, legal obligations exist for a minority of our onshore right-of-way agreements due to requirements or landowner options to compel us to remove the pipe at final abandonment. Sufficient data exists with certain onshore pipeline systems to reasonably estimate an abandonment retirement obligation cost. However, in some cases, there is insufficient information to reasonably determine the timing and/or method of settlement for estimating the fair value of the asset retirement obligation. In these cases, the asset retirement obligation cost is considered indeterminate because there is no data or information that can be derived from past practice, industry practice, management's intent, or the asset's estimated economic life. Useful lives of most pipeline systems are primarily derived from available supply resources and the ultimate consumption of those resources by end users. Variables can affect the remaining lives of the assets which preclude us from making a reasonable estimate of the ARO. Indeterminate ARO costs will be recognized in the period in which sufficient information exists to reasonably estimate potential settlement dates and methods.

Derivative Financial Instruments

Our net income and cash flows are subject to volatility stemming from changes in interest rates and commodity prices of natural gas, NGLs, condensate and fractionation margins (the relative price differential between NGL sales and the offsetting natural gas purchases). To reduce the volatility of our cash flows, we use derivative financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to manage the purchase and sales prices of the commodities and fix the interest rate on our variable rate debt.

The accounting treatment for our derivative financial instruments is determined by the guidance of SFAS No. 133 and is dependent on each instrument's intended use, how it is designated and the extent to which the derivative financial instrument is effective in reducing the risk that it is intended to hedge. To qualify for hedge accounting, very specific requirements must be met in terms of hedge structure, hedge objective and hedge documentation.

Derivative financial instruments qualifying for hedge accounting treatment that we use can generally be divided into two categories: 1) cash flow hedges, or 2) fair value hedges. We enter into cash flow hedges to reduce the variability in cash flows related to forecasted transactions. We enter into fair value hedges to reduce the risk of changes in the value of a recognized asset or liability. Cash flow and fair value hedges are considered highly effective if they are able to substantially offset (i.e., more than 80 percent) the changes in cash flow or fair value of the risk that is being hedged. The extent to which a derivative financial instrument designated as a hedge does not offset the changes in cash flow or fair value of the risk being hedged is considered ineffective. At inception and on an ongoing basis we assess whether the derivative financial instruments we use in our hedging transactions are highly effective in offsetting changes in cash flows or fair values of the hedged items.

All of our derivative financial instruments are recorded in our consolidated financial statements at fair market value as current and long-term assets or liabilities on a net basis by counterparty and are adjusted each period for changes in the fair market value. The fair market value of these derivative financial instruments reflects the estimated amounts that we would pay or receive to terminate or close the contracts at the reporting date, taking into account the current unrealized losses or gains on open contracts. We use external market quotes and indices to value substantially all of the financial instruments we utilize.

Derivative financial instruments that we designate and qualify as cash flow or fair value hedges under the requirements of SFAS No. 133, receive hedge accounting treatment for the effective portion of the derivative financial instrument. Under hedge accounting, any unrealized gain or loss in fair market value of the effective portion of a derivative financial instrument designated as a cash flow hedge is recorded as an asset or liability with an offset deferred in Accumulated other comprehensive income ("AOCI"), a component of partners' capital, until the underlying hedged transaction occurs. Realized gains and losses on derivative financial instruments that are designated as cash flow hedges of forecasted commodity purchases and sales are included in cost of natural gas and cash flow hedges of forecasted interest payments are included in Interest expense on our consolidated statements of income in the period the hedged transaction occurs. Under hedge accounting, the realized and unrealized gain or loss in the fair market value of a derivative financial instrument designated as a fair value hedge is recorded as an asset or a liability with the offset recorded in our consolidated statements of income as a component of Cost of natural gas for fair value hedges of our commodities and as a component of interest expense for fair value hedges of our indebtedness both of which are offset by the changes in the fair market value of the underlying hedged item.

Under the guidance of SFAS No. 133, the changes in fair market value, both realized and unrealized gains and losses, of derivative financial instruments that 1) do not qualify for hedge accounting, 2) are not designated as hedges and 3) are ineffective, are recognized each period in our consolidated statements of income. These changes in fair market value are recognized as a component of cost of natural gas for our commodity derivative financial instruments and as a component of interest expense for derivative financial instruments of our interest rates. We refer to the accounting treatment for derivative financial instruments that do not qualify for hedge accounting as mark-to-market accounting. Our preference, whenever possible, is for our derivative financial instruments to receive hedge accounting treatment to mitigate the non cash earnings volatility that arises under mark-to-market accounting treatment.

Our cash flow is only affected to the extent the actual derivative contract is settled by 1) making or receiving a payment to/from the counterparty; or 2) by making or receiving a payment for entering into a contract that exactly offsets the original derivative contract. Typically, a derivative contract is settled when the physical transaction that underlies the derivative financial instrument occurs.

Gains and losses that we have deferred in AOCI related to cash flow hedges for which hedge accounting has been discontinued, remain in AOCI until the underlying physical transaction occurs unless it is probable that the forecasted transaction will not occur by the end of the originally specified time period or within an additional two-month period of time thereafter.

One of the primary factors that can affect our operating results each period is the price assumptions we use to value our derivative financial instruments. To the extent that these derivative financial instruments are ineffective or do not qualify for hedge accounting treatment under the requirements of SFAS No. 133, they are accounted for using the mark-to-market method of accounting and any change in the fair market value is reflected in our consolidated statements of income as a component of cost of natural gas or interest expense, depending on whether the derivative financial instrument relates to a commodity or interest rate. We use published market price information where available, or quotations from OTC market makers to find executable bids and offers. The valuations also reflect the potential impact of liquidating our position in an orderly manner over a reasonable period of time under present market conditions, modeling risk, credit risk of our counterparties and operational risk. The amounts we report in our consolidated financial statements change quarterly as these estimates are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond our control.

Commitments, Contingencies and Environmental Liabilities

We accrue reserves for contingent liabilities, including environmental remediation and clean-up costs, when our assessments indicate that it is probable that a liability has been incurred and an amount can be reasonably estimated. Estimates of the liabilities are based on currently available facts, existing technology and presently enacted laws and regulations taking into consideration the likely effects of inflation and other factors, and include estimates of associated legal costs. These estimates also consider prior experience remediating contaminated sites, other companies' clean-up experience and data released by government organizations. Our estimates are subject to revision in future periods based on actual costs or new circumstances and any revisions are reflected in our earnings in the period in which they are reasonably determinable. We evaluate recoveries from insurance coverage separately from our liability and, when recovery is reasonably assured, we record and report an asset separately from the associated liability in our financial statements. New environmental developments, such as increasingly strict environmental laws and regulations and new claims for damages to property, employees, other persons and the environment resulting from our current or past operations, could result in substantial cost and future liabilities.

We recognize liabilities for other contingencies when we have an exposure that, when fully analyzed, indicates it is both probable that an asset has been impaired or that a liability has been incurred and the amount of impairment or loss can be reasonably estimated. Both internal and external legal counsel evaluate our potential exposure to adverse outcomes. When a range of probable loss can be estimated, we accrue the most likely amount, or at least the minimum of the range of probable loss. To the extent that actual outcomes differ from our estimates, or additional facts and circumstances cause us to review our estimates, income may be affected.

Crude Oil Over/Short Balance and Crude Oil Measurement Gains/Losses

Crude oil over/short balance and crude oil measurement gains/losses are inherent in the transportation of crude oil due to evaporation, measurement differences and blending of commodities in transit in addition to other factors. We estimate our crude oil measurement gains/losses and our crude oil over/short balance based on mathematical calculations and physical measurements, which include assumptions about the type of crude oil, its market value, normal physical losses due to evaporation and capacity limitations of the system. A material change in these assumptions may result in a change to the carrying value of our crude oil over/short balance or revision of our crude oil measurement gain/loss estimates. We include the crude oil measurement gains/losses in our operating and administrative expenses on our consolidated statements of income and the crude oil over/short balance in accounts payable and other in the consolidated statements of financial position if the balance is a liability and in inventory if the balance is in an asset position.

Operational Balancing Agreements and Natural Gas Imbalances

We record payables and receivables associated with our natural gas pipeline operational balancing agreements and natural gas imbalances monthly when a customer delivers more or less natural gas into our pipelines than they remove. These balances are either settled on a cash basis or are carried by the pipelines and shippers on an in-kind basis. We primarily estimate the value of the imbalances at month-end spot prices based on published third-party indices for the locations where the imbalances are derived using the best available third party and internal volume information. If there is a change to these estimates and assumptions, actual results may differ.

RECENT ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

Fair Value Option for Financial Assets and Liabilities

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Liabilities*. This statement provides companies with an option to report certain financial assets and financial liabilities at fair value. The objective of SFAS No. 159 is to reduce the volatility in earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. SFAS No. 159 also establishes presentation and disclosure requirements designed to facilitate comparisons between companies that choose different measurement attributes for similar types of assets and liabilities. The provisions of SFAS No. 159 are effective at the beginning of our first fiscal year that begins after November 15, 2007, as we have elected not to early adopt the provisions of SFAS No. 159. We do not expect our adoption of SFAS No. 159 to have a material effect on our consolidated financial statements.

Fair Value Measurements

In September 2006, the Financial Accounting Standards Board (FASB) issued FASB Statement No. 157, *Fair Value Measurements*. This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles (GAAP), and expands disclosures about fair value measurement. The statement is effective for fiscal years beginning after November 15, 2007, and with limited exceptions is to be applied prospectively as of the beginning of the fiscal year initially adopted. We do not expect our adoption of this pronouncement to materially affect our financial statements. However, adoption of this pronouncement may affect our disclosures regarding derivative financial instruments and indebtedness.

Business Combinations

In December 2007, the Financial Accounting Standards Board issued Statement No. 141(R), *Business Combinations*, which we refer to as SFAS No. 141(R). The new standard retains the fundamental requirements in FASB Statement No. 141, *Business Combinations*, that the acquisition method of accounting (previously referred to as the *purchase method)*, be used for all business combinations and for an acquirer to be identified for each business combination. Among other items, SFAS No. 141(R) requires the following:

- Assets acquired, liabilities assumed and any noncontrolling interest in the acquiree at the acquisition date are to be measured at their fair values as of that date.
- Costs associated with effecting an acquisition and restructuring costs the acquirer was not obligated to incur are recognized separately from the business combination.
- Assets acquired and liabilities assumed arising from contractual contingencies as of the acquisition date are measured at their acquisition-date fair values.
- Noncontractual contingencies as of the acquisition date are measured at the acquisition-date fair values only if it is more likely than not that they meet the definition of an asset or liability in FASB Concepts Statement No. 6, *Elements of Financial Statements*.
- Assets and liabilities arising from contingencies are to be reported at the acquisition-date fair value absent new information about the possible outcome, however, when new information becomes available, liabilities are measured at the higher of the acquisition date fair value or the FASB Statement No. 5, *Accounting for Contingencies* (SFAS No. 5) amount while assets are measured at the lower of the acquisition date fair value or the best estimate of the future settlement amount.

- Goodwill as of the acquisition date is determined as the excess of the fair value of the consideration transferred plus the fair value of any noncontrolling interest plus the fair value of previously held equity interests less the fair values of the identifiable net assets acquired.

- Recognition of a gain in earnings attributable to the acquirer when the total acquisition date fair value of the identifiable net assets acquired exceed the fair value of the consideration transferred plus any noncontrolling interest in the acquiree.

- Contingent consideration at the acquisition date is measured at its fair value at that date.

- Retroactively recognize adjustments made during the measurement period (not more than one year from the acquisition date) as if the accounting had occurred on the acquisition date.

SFAS No. 141(R) applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008, and early adoption is not permitted. Among other things, the provisions of this statement will require us to expense certain costs associated with acquisitions that were previously permitted to be capitalized which may affect our operating results in periods that we complete an acquisition.

Noncontrolling Interests

In December 2007, the Financial Accounting Standards Board issued FASB Statement No. 160, *Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51*, to establish accounting and reporting standards for the noncontrolling interest in a subsidiary and for deconsolidation of a subsidiary. Among other provisions, SFAS No. 160 requires the following:

- The ownership in subsidiaries held by parties other than the parent is presented in the consolidated statement of financial position within equity, but separate from the parent's equity.

- The amount of consolidated net income attributable to the parent and the noncontrolling interest is presented on the face of the consolidated statement of income.

- Changes in a parent's ownership interest while the parent retains its controlling financial interest in its subsidiary are accounted for as equity transactions.

- Any retained noncontrolling equity investment in a subsidiary that is deconsolidated be initially measured at fair value.

- Sufficient disclosures that clearly identify and distinguish between the interests of the parent and the interests of the noncontrolling owners.

SFAS No. 160 is effective for fiscal years, and interim periods within those years, beginning on or after December 15, 2008, and early adoption is prohibited. SFAS No. 160 requires prospective adoption as of the beginning of the fiscal year in which the provisions are initially applied, except for the presentation and disclosure requirements which shall be applied retrospectively for all periods presented. Our adoption of this standard will not have a material effect on our financial position or results of operations.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

INTEREST RATE RISK

We utilize both fixed and variable interest rate debt, and are exposed to market risk resulting from the variable interest rates on our Credit Facility and the frequent changes in interest rates when we re-issue maturing commercial paper. To the extent that we frequently issue and re-issue commercial paper at short-term interest rates and have amounts drawn under our credit facilities at floating rates of interest, our earnings and cash flows are exposed to changes in interest rates. This exposure is managed through periodically refinancing commercial paper and floating-rate bank debt with long-term fixed rate debt and through the use of interest rate derivative financial instruments including futures, forwards, swaps, options and other financial instruments with similar characteristics. We do not have any material exposure to movements in foreign exchange rates as virtually all of our revenues and expenses are denominated in U.S. dollars. To the extent that a material foreign exchange exposure arises, we intend to hedge such exposure using derivative financial instruments.

The following table presents the principal cash flows and related weighted average interest rates by expected maturity dates along with the carrying values and fair values of our third-party debt obligations as of December 31, 2007 and 2006.

	December 31, 2007									December 31, 2006	
		Expected Maturity of Carrying Amounts by Fiscal Year									
	Average Interest Rate	2008	2009	2010	2011	2012	Thereafter	Total	Fair Value	Carrying Amount	Fair Value
	(dollars in millions)										
Liabilities											
Fixed Rate:											
First Mortgage Notes	9.150%	$ 31.0	$ 31.0	$ 31.0	$ 31.0	$ —	$ —	$ 124.0	$ 135.1	$ 155.0	$169.5
Senior notes due 2009	4.000%	—	200.0	—	—	—	—	200.0	198.5	200.0	194.2
Senior, unsecured zero coupon notes due 2022	5.358%	—	203.6	—	—	—	—	203.6	210.7	—	—
Senior notes due 2012	7.900%	—	—	—	—	99.9	—	99.9	110.2	99.9	110.5
Senior notes due 2013	4.750%	—	—	—	—	—	199.8	199.8	192.0	199.8	188.6
Senior notes due 2014	5.350%	—	—	—	—	—	199.9	199.9	194.3	199.9	193.0
Senior notes due 2016	5.875%	—	—	—	—	—	299.7	299.7	293.7	299.7	297.4
Senior notes due 2018	7.000%	—	—	—	—	—	99.9	99.9	105.3	99.8	107.9
Senior notes due 2028	7.125%	—	—	—	—	—	99.8	99.8	104.3	99.8	108.9
Senior notes due 2033	5.950%	—	—	—	—	—	199.7	199.7	176.9	199.7	186.2
Senior notes due 2034	6.300%	—	—	—	—	—	99.8	99.8	92.1	99.8	97.1
Junior subordinated notes due 2067	8.050%	—	—	—	—	—	399.3	399.3	385.9	—	—
Variable Rate:											
Commercial paper	5.360%	—	—	—	—	268.5	—	268.5	268.5	443.7	443.7
Credit Facility	5.220%	—	—	—	—	400.0	—	400.0	400.0	—	—

Our net income and cash flows are subject to volatility stemming from changes in interest rates on our variable rate debt obligations. Our interest rate risk exposure does not exist within any of our segments, but exists at the corporate level where our variable rate debt obligations are issued. To mitigate the volatility of our cash flows, we use derivative financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to manage the risks associated with market fluctuations in interest rates. Based on our risk management policies, all of our derivative financial instruments are employed in connection with an underlying asset, liability and/or forecasted transaction and are not entered into with the objective of speculating on interest rates.

The table below provides information about our derivative financial instruments that we use to hedge the interest payments on our variable rate debt obligations which are sensitive to changes in interest rates and to lock in the interest rate on anticipated issuances of debt in the future. For interest rate swaps, the table presents notional amounts, the rates charged on the underlying notional and weighted average interest rates paid by expected maturity dates. Notional amounts are used to calculate the contractual payments to be exchanged under the contract. Weighted average variable rates are based on implied forward rates in the yield curve at December 31, 2007.

	December 31, 2007									December 31, 2006		
	Expected Fiscal Year of Maturity of Notional Amounts											
	Notional Amount	2008	2009	2010	2011	2012	Thereafter	Fair Value		Notional Amount	Fair Value	
								Asset	Liability		Asset	Liability
	(dollars in millions)											
Interest Rate Derivatives												
Interest Rate Swaps:												
Floating to Fixed	$ 325.0	$ (1.5)	$ (1.4)	$ (0.5)	$ —	$ 0.3	$ 0.1	$ —	$ (3.0)	$ 525.0	$ 4.3	$ —
Average Pay Rate	4.41%	4.51%	4.39%	4.35%	4.35%	4.35%	4.35%	—	—	4.41%		
Average Receive Rate		LIBOR-0.21%	LIBOR-0.21%	LIBOR-0.21%	LIBOR-0.21%	LIBOR-0.21%	LIBOR-0.21%	—	—	LIBOR		
Fixed to Floating	$ 125.0	$ 1.0	$ 1.7	$ 0.9	$ 0.4	$ 0.1	$ —	$ 4.1	$ —	$ 125.0	$ —	$ (1.3)
Average Pay Rate	LIBOR-0.21%	LIBOR-0.21%	LIBOR-0.21%	LIBOR-0.21%	LIBOR-0.21%	LIBOR-0.21%	LIBOR-0.21%	—	—	LIBOR-0.21%		
Average Receive Rate	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	—	—	4.75%		
Treasury Locks:												
Floating to Fixed	$ 200.0	$ (8.3)	$ —	$ —	$ —	$ —	$ —	$ —	$ (8.3)	$ 200.0	$ 2.8	$ —
Average Pay Rate	4.04%	4.04%	—	—	—	—	—	—	—	4.68%		
Average Receive Rate	10YR-UST	10YR-UST	—	—	—	—	—	—	—	30YR-UST		
Interest Rate Collars:												
Calls	$ 100.0	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 100.0	$ 0.1	$ —
Average Pay Rate	5.50%	5.50%	5.50%	—	—	—	—	—	—	5.50%		
Average Receive Rate	LIBOR	LIBOR	LIBOR	—	—	—	—	—	—	LIBOR		
Puts	$ 100.0	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 100.0	$ —	$ —
Average Pay Rate	4.17%	4.17%	4.17%	—	—	—	—	—	—	4.17%		
Average Receive Rate	LIBOR	LIBOR	LIBOR	—	—	—	—	—	—	—		

(1) LIBOR refers to the three-month U.S. London Interbank Offered Rate.

(2) UST refers to United States Treasury notes.

Our treasury locks and a portion of our interest rate collars maturing in 2008 qualify for hedge accounting treatment pursuant to the requirements of SFAS No. 133 and have been designated as cash flow hedges of future interest payments on the first $200 million of an anticipated debt issuance and interest payments on $50 million of our variable rate indebtedness, respectively. As such, the fair value of these derivative financial instruments is recorded as assets or liabilities on our consolidated statements of financial position with the changes in fair value recorded as corresponding increases or decreases in AOCI. Our floating to fixed rate interest rate swaps and a portion of our interest rate collars maturing in 2008 and 2009 hedging $250 million of our variable rate indebtedness did not qualify for hedge accounting treatment as set forth in SFAS No. 133 at December 31, 2007. As such, changes in the fair value of these derivative financial instruments are recorded in earnings as an increase or decrease in interest expense. A portion of these transactions have subsequently been re-designated as cash flow hedges of forecast floating rate indebtedness.

The floating to fixed rate and fixed to floating rate interest rate swaps maturing in 2013 have not been designated as cash flow or fair value hedges under SFAS No. 133 and, as a result, changes in the fair value of these derivative financial instruments are recorded in earnings as an increase or decrease in interest expense.

COMMODITY PRICE RISK

Our net income and cash flows are subject to volatility stemming from changes in commodity prices of natural gas, NGLs, condensate and fractionation margins (the relative price differential between NGL sales and the offsetting natural gas purchases). Our exposure to commodity price risk exists within our Natural Gas and Marketing segments. To mitigate the volatility of our cash flows, we use derivative financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to manage the risks associated with market fluctuations in commodity prices. Based on our risk management policies, all of our derivative financial instruments are employed in connection with an underlying asset, liability and/or forecasted transaction and are not entered into with the objective of speculating on commodity prices.

The following tables provide information about our derivative financial instruments at December 31, 2007 and December 31, 2006, with respect to our commodity price risk management activities for natural gas and NGLs, including condensate:

	At December 31, 2007						At December 31, 2006	
			Wtd Avg Price(2)		Fair Value(3)		Fair Value(3)	
	Commodity	Notional(1)	Receive	Pay	Asset	Liability	Asset	Liability
Contracts maturing in 2008								
Swaps								
Receive variable/pay fixed	Natural gas	38,223,919	$ 7.19	$ 7.37	$ 7.6	$ (14.5)	$ 9.5	$ (5.1)
Receive fixed/pay variable	Natural gas	33,193,191	6.57	7.48	10.3	(39.8)	3.6	(44.1)
	NGL	5,776,578	42.37	59.87	—	(98.9)	2.5	(7.7)
	Crude oil	439,721	52.04	93.17	—	(17.7)	—	(7.0)
Receive variable/pay variable	Natural gas	99,960,535	7.32	7.28	7.0	(3.5)	2.5	(0.4)
Options								
Calls (written)	Natural gas	366,000	4.31	7.80	—	(1.3)	—	(1.3)
Puts purchased	Natural gas	306,000	7.91	3.40	—	—	—	—
	NGL	398,403	64.00	44.88	0.1	—	—	—
Contracts maturing in 2009								
Swaps								
Receive variable/pay fixed	Natural gas	11,813,065	7.94	7.59	5.5	(1.6)	2.9	(2.1)
Receive fixed/pay variable	Natural gas	14,966,095	5.54	8.41	1.2	(41.8)	0.7	(31.5)
	NGL	3,204,335	44.22	58.66	—	(43.6)	1.4	(1.4)
	Crude oil	264,625	59.09	87.96	—	(7.2)	—	(1.9)
Receive variable/pay variable	Natural gas	67,100,864	8.32	8.30	2.9	(1.8)	1.4	(0.6)
Options								
Calls (written)	Natural gas	365,000	4.31	8.51	—	(1.5)	—	(1.2)
Puts	Natural gas	365,000	8.51	3.40	—	—	—	—
	NGL	365,000	58.59	42.09	0.6	—	—	—
Contracts maturing in 2010								
Swaps								
Receive variable/pay fixed	Natural gas	2,413,505	8.24	6.23	4.4	—	2.5	(0.3)
Receive fixed/pay variable	Natural gas	9,670,000	4.19	8.51	—	(38.0)	0.2	(26.1)
	NGL	866,875	35.69	53.23	—	(13.8)	—	(1.5)
	Crude oil	259,150	66.83	85.73	—	(4.4)	—	(0.6)
Receive variable/pay variable	Natural gas	35,935,000	8.53	8.5	1.5	(0.7)	0.8	(0.1)
Options								
Calls (written)	Natural gas	365,000	4.31	8.58	—	(1.4)	—	(1.0)
Puts	Natural gas	365,000	8.58	3.40	—	—	—	—
Contracts maturing in 2011								
Swaps								
Receive variable/pay fixed	Natural gas	817,005	8.46	4.00	3.2	—	2.0	—
Receive fixed/pay variable	Natural gas	7,952,500	3.63	8.54	—	(34.1)	—	(21.5)
	NGL	316,090	36.02	51.86	—	(4.3)	—	(0.6)
	Crude oil	228,125	68.36	85.40	—	(3.4)	—	(0.2)
Receive variable/pay variable	Natural gas	4,185,000	7.99	7.95	0.1	—	—	—
Options								
Calls (written)	Natural gas	365,000	4.31	8.55	—	(1.4)	—	(0.9)
Puts	Natural gas	365,000	8.55	3.40	—	—	—	—
Contracts maturing in 2012								
Swaps								
Receive variable/pay fixed	Natural gas	209,709	8.90	4.10	0.9	—	0.6	—
Receive fixed/pay variable	Natural gas	1,456,000	3.57	9.04	—	(6.8)	—	(4.5)
	Crude oil	219,600	74.85	85.39	—	(1.9)	—	—
Receive variable/pay variable	Natural gas	1,089,000	7.96	7.92	—	—	—	—

(1) Volumes of Natural gas are measured in MMBtu, whereas volumes of NGL and Crude are measured in Bbl.

(2) Weighted average prices received and paid are in $/MMBtu for Natural gas and in $/Bbl for NGL and Crude.

(3) The fair value is determined based on quoted market prices at December 31, 2007 and December 31, 2006, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values are presented in millions of dollars.

Accounting Treatment

All derivative financial instruments are recorded in the consolidated financial statements at fair market value and are adjusted each period for changes in the fair market value ("mark-to-market"). The fair market value of these derivative financial instruments reflects the estimated amounts that we would pay or receive, other than in a forced or liquidation sale, to terminate or close the contracts at the reporting date, taking into account the current unrealized losses or gains on open contracts. We use actively traded external market quotes and indices to value substantially all of the financial instruments we utilize.

Under the guidance of SFAS No. 133, if a derivative financial instrument does not qualify as a hedge, or is not designated as a hedge, the derivative is adjusted to its fair market value, or marked-to-market, each period with the increases and decreases in fair value recorded in our consolidated statements of income as increases and decreases in cost of natural gas for our commodity-based derivatives and Interest expense for our interest rate derivatives. Cash flow is only impacted to the extent the actual derivative contract is settled by making or receiving a payment to or from the counterparty or by making or receiving a payment for entering into a contract that exactly offsets the original derivative contract. Typically, we settle our derivative contracts when the physical transaction that underlies the derivative financial instrument occurs.

If a derivative financial instrument qualifies and is designated as a cash flow hedge, a hedge of a forecasted transaction or future cash flows, any unrealized mark-to-market gain or loss is deferred in Accumulated other comprehensive income ("AOCI"), a component of Partners' Capital, until the underlying hedged transaction occurs. To the extent that the hedge instrument is effective in offsetting the transaction being hedged, there is no impact to the income statement. At inception and on a quarterly basis, we formally assess whether the hedge contract is highly effective in offsetting changes in cash flows of hedged items. Any ineffective portion of a cash flow hedge's change in fair market value is recognized each period in earnings. Realized gains and losses on derivative financial instruments that are designated as hedges and qualify for hedge accounting are included in Cost of natural gas for commodity hedges and Interest expense for interest rate hedges in the period the hedged transaction occurs. Gains and losses deferred in AOCI related to cash flow hedges, for which hedge accounting has been discontinued, remain in AOCI until the underlying physical transaction occurs unless it is probable that the forecasted transaction will not occur by the end of the originally specified time period, or within an additional two-month period of time thereafter. Generally, our preference is for our derivative financial instruments to receive hedge accounting treatment whenever possible, to mitigate the non-cash earnings volatility that arises under from recording the changes in fair value of our derivative financial instruments through earnings. To qualify for cash flow hedge accounting as set forth in SFAS No. 133, very specific requirements must be met in terms of hedge structure, hedge objective and hedge documentation.

If a derivative financial instrument is designated and qualifies as a fair value hedge of the change in fair market value of an underlying asset or liability, the gain or loss resulting from the change in fair market value of the derivative financial instrument is recorded in earnings adjusted by the gain or loss resulting from the change in fair market value of the underlying asset or liability. Any ineffective portion of a fair value hedge's change in fair market value will be recorded in earnings as the amount that is not offset by the gain or loss on the change in fair market value of the underlying asset or liability. We include the gains and losses associated with derivative financial instruments designated and qualifying as fair value hedges of our debt obligations in interest expense on our consolidated statements of income. Similar to derivative financial instruments designated as cash flow hedges, very specific requirements must be met in terms of hedge structure, hedge objective and hedge documentation.

Non-Qualified Hedges

Many of our derivative financial instruments qualify for hedge accounting treatment under the specific requirements of SFAS No. 133. However, we have four primary transaction types associated with our commodity derivative financial instruments where the hedge structure does not meet the requirements to apply hedge accounting. As a result, these derivative financial instruments do not qualify for hedge accounting under SFAS No. 133 and are referred to as "non-qualified." These non-qualified derivative financial instruments are marked-to-market each period with the change in fair value, representing unrealized gains and losses, included in cost of natural gas in our consolidated statements of income. These mark-to-market adjustments produce a degree of earnings volatility that can often be significant from period to period, but have no cash flow impact relative to changes in market prices. The cash flow impact occurs when the underlying physical transaction takes place in the future and when the associated financial instrument contract settlement is made.

The four primary transaction types that do not qualify for hedge accounting are as follows:

1. **Transportation—**In our Marketing segment, when we transport natural gas from one location to another the pricing index used for natural gas sales is usually different from the pricing index used for natural gas purchases, which exposes us to market price risk relative to changes in those two indices. By entering into a basis swap, where we exchange one pricing index for another, we can effectively lock in the margin, representing the difference between the sales price and the purchase price, on the combined natural gas purchase and natural gas sale, removing any market price risk on the physical transactions. Although this represents a sound economic hedging strategy, the derivative financial instruments (i.e., the basis swaps) we use to manage the commodity price risk associated with these transportation contracts do not qualify for hedge accounting under SFAS No. 133, since only the future margin has been fixed and not the future cash flow. As a result, the changes in fair value of these derivative financial instruments are recorded in earnings.

2. **Storage—**In our Marketing segment, we use derivative financial instruments (i.e., natural gas swaps) to hedge the relative difference between the injection price paid to purchase and store natural gas and the withdrawal price at which the natural gas is sold from storage. The intent of these derivative financial instruments is to lock in the margin, representing the difference between the price paid for the natural gas injected and the price received upon withdrawal of the gas from storage in a future period. We do not pursue cash flow hedge accounting treatment for these storage transactions since the underlying forecasted injection or withdrawal of natural gas may not occur in the period as originally forecast. This can occur because we have the flexibility to make changes in the underlying injection or withdrawal schedule, given changes in market conditions. In addition, since the physical natural gas is recorded at the lower of cost or market, timing differences can result when the derivative financial instrument is settled in a period that is different from when the physical natural gas is sold from storage. As a result, derivative financial instruments associated with our natural gas storage activities can create volatility in our earnings.

3. **Natural Gas Collars—**In our Natural Gas segment, we had previously entered into natural gas collars to hedge the sales price of natural gas. The natural gas collars were based on a NYMEX price, while the physical gas sales were based on a different index. To better align the index of the natural gas collars with the index of the underlying sales, we de-designated the original cash flow hedging relationship with the intent of contemporaneously re-designating the natural gas collars as hedges of forecasted physical natural gas sales with a NYMEX pricing index. However, because the fair value of these derivative instruments was a liability to us at re-designation, they are considered net written options under SFAS No. 133 and do not qualify for hedge accounting. These derivatives are being marked-to-market, with the changes in fair value from the date of de-designation recorded to earnings each period. As a result, our operating income will be

subject to greater volatility due to movements in the prices of natural gas until the underlying long-term transactions are settled.

4. **Optional Natural Gas Processing Volumes—**In our Natural Gas segment we use derivative financial instruments to hedge the volumes of NGLs produced from our natural gas processing facilities. Our natural gas contracts allow us the option of processing natural gas when it is economical, and ceasing to do so when processing becomes uneconomic. We have entered into derivative financial instruments to fix the sales price of a portion of the NGLs that we produce at our discretion and to fix the associated purchases of natural gas required for processing. We will designate derivative financial instruments associated with NGLs we produce at our discretion as cash flow hedges when the processing of natural gas is probable of occurrence. However, we are precluded from designating the derivative financial instruments entered to manage the respective commodity price risk when we are unable to accurately forecast the NGLs to be processed at our discretion. As a result, our operating income will be subject to increased volatility due to fluctuations in NGL prices until the underlying transactions are settled or offset.

In each of the instances described above, the underlying physical purchase, storage and sale of natural gas and NGLs are accounted for on a historical cost or market basis rather than on the mark-to-market basis we utilize for the derivative financial instruments employed to mitigate the commodity price risk associated with our storage and transportation assets. This difference in accounting (i.e., the derivative financial instruments are recorded at fair market value while the physical transactions are recorded at historical cost) can and has resulted in volatility in our reported net income, even though the economic margin is essentially unchanged from the date the transactions were consummated.

We routinely enter into interest rate swaps to fix the interest rates associated with our variable rate debt, including commercial paper and bank borrowings. In August 2007, we entered into forward-starting interest rate swaps that we designated as cash flow hedges of variable rate debt to begin in October 2007 and November 2007. The specific floating rate borrowings did not take place as initially forecast, thereby causing the interest rates swaps to no longer qualify as cash flow hedges. As a result, we recorded a charge to interest expense of $1.4 million, representing the fair market value of the interest rate swaps at December 31, 2007. A portion of these transactions have subsequently been re-designated as cash flow hedges of forecast floating rate indebtedness.

Discontinuance of Hedge Accounting

In 2005, we discontinued application of hedge accounting in connection with some of our derivative financial instruments designated as hedges of forecasted sales and purchases of natural gas. We discontinued application of hedge accounting when we determined it was no longer probable that the originally forecasted purchases and sales of natural gas would occur by the end of the originally specified time period, or within an additional two-month period of time thereafter. As discussed above, this can occur because we have the flexibility to make changes to the underlying delivery locations for our transportation assets and to the underlying injection or withdrawal schedule for our storage assets, given changes in market conditions. One of the key criteria to achieve hedge accounting under SFAS No. 133 is that the forecasted transaction be probable of occurring as originally set forth in the hedge documentation. As a result, in 2005, we recognized previously deferred unrealized losses in our Marketing segment of approximately $9.0 million from the discontinuance of hedge accounting. In doing so, we reclassified the $9.0 million to cost of natural gas on our consolidated statements of income from AOCI. Going forward, the derivative financial instruments for which hedge accounting has been discontinued are considered to be non-qualified under SFAS No. 133, and must be marked-to-market each period, with the increases and decreases in fair value recorded as increases and decreases in earnings. Also included in the loss from discontinuance are approximately $2.1 million of net mark-to-market losses that relate to hedge positions that were closed out in 2005.

The following table presents the unrealized gains and losses associated with changes in the fair value of our derivatives, which are recorded as an element of cost of natural gas and interest expense in our consolidated statements of income and disclosed as a reconciling item on our consolidated statements of cash flows:

Derivative fair value gains (losses)	December 31, 2007	December 31, 2006	December 31, 2005
		(in millions)	
Natural Gas segment			
Hedge ineffectiveness	$ —	$ (1.9)	$ (2.5)
Non-qualified hedges	(59.0)	1.8	(5.6)
Marketing			
Non-qualified hedges	(3.8)	64.5	(41.3)
Discontinued hedges	—	—	(9.0)
Commodity derivative fair value gains (losses)	(62.8)	64.4	(58.4)
Corporate			
Non-qualified interest rate hedges	(1.4)	—	—
Derivative fair value gains (losses)	$ (64.2)	$ 64.4	$ (58.4)

De-designation and Settlement of Derivatives

In connection with the sale of assets in December 2005, as discussed in Note 3 to the consolidated financial statements beginning on page F-1 of this report, we settled for cash of approximately $16.3 million, natural gas collars representing derivative financial instruments on sales of 2,000 MMBtu/d of natural gas through 2011. We had previously recorded unrealized losses associated with the natural gas collars that were realized upon settlement. Additionally, we de-designated derivative financial instruments that qualified for and were designated as cash flow hedges of forecasted sales of 273 Bpd of NGLs through 2007 and contemporaneously closed out the position by entering into an offsetting derivative financial instrument, at market, on forecasted purchases of 273 Bpd of NGLs through 2007.

Derivative Positions

Our derivative financial instruments are included at their fair values in the consolidated statements of financial position as follows:

	December 31, 2007	December 31, 2006
	(in millions)	
Receivables, trade and other	$ 6.5	$ 7.2
Other assets, net	6.4	11.0
Accounts payable and other	(165.5)	(57.2)
Other long-term liabilities	(192.9)	(136.4)
	$ (345.5)	$ (175.4)

The increase in our obligation associated with derivative activities is primarily due to the increase in current and forward natural gas and NGL prices from December 31, 2006 to December 31, 2007. Our portfolio of derivative financial instruments is largely comprised of long-term fixed price natural gas sales and purchase agreements.

We record the change in fair value of our highly effective cash flow hedges in AOCI until the derivative financial instruments are settled, at which time they are reclassified to earnings. We regularly enter into treasury locks to hedge the interest on anticipated issuances of indebtedness. The settlement of a treasury lock can result in the retention of unrecognized gains or losses in AOCI that are amortized to interest expense over the life of the related debt issuance. In connection with our 2007 issuance and sale of $400 million in principal amount of our Junior Notes, we paid $0.9 million to settle treasury locks we entered to hedge the first five years of interest payments on a portion of this obligation. The $0.9 million is being amortized from AOCI to interest expense over the five year period for which the derivative instrument was established to hedge of interest payments on the junior notes. In December 2006, we paid $10.2 million to settle treasury locks we entered to hedge a portion of the interest payments associated with our issuance of $300 million in principal amount of our senior notes. The $10.2 million is being amortized from AOCI to interest expense over the 10-year life of the senior notes.

Also included in AOCI are unrecognized losses of approximately $2.0 million associated with derivative financial instruments that qualified for and were classified as cash flow hedges of forecasted commodity transactions that were subsequently de-designated. These unrealized losses are reclassified to earnings over the periods during which the originally hedged forecasted transactions affect earnings. For the years ended December 31, 2007, 2006 and 2005, we reclassified unrealized losses of $94.8 million, $78.3 million and $33.8 million, respectively, from AOCI to cost of natural gas on our consolidated statements of income for the fair value of derivative financial instruments that were settled. We estimate that approximately $113 million of AOCI representing unrealized net losses on cash flow hedging activities at December 31, 2007, will be reclassified to earnings during the next twelve months.

We do not require collateral or other security from the counterparties to our derivative financial instruments, all of which were rated "BBB+" or better by the major credit rating agencies.

Item 8. Financial Statements and Supplementary Data

Our consolidated financial statements, together with the notes thereto and the independent registered public accounting firm's report thereon, and unaudited supplementary information, appear beginning on page F-2 of this report, and are incorporated by reference. Reference should be made to the "Index to Financial Statements, Supplementary Information and Financial Statement Schedules" on page F-1 of this report.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

DISCLOSURE CONTROLS AND PROCEDURES

We and Enbridge maintain systems of disclosure controls and procedures designed to provide reasonable assurance that we are able to record, process, summarize and report the information required in our annual and quarterly reports under the Securities Exchange Act of 1934. Our management has evaluated the effectiveness of our disclosure controls and procedures as of December 31, 2007. Based upon that evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures are effective to accomplish their purpose. In conducting this assessment, our management relied on similar evaluations conducted by employees of Enbridge affiliates who provide certain treasury, accounting and other services on our behalf.

INTERNAL CONTROL OVER FINANCIAL REPORTING

Management's Annual Report on Internal Control Over Financial Reporting

Management of Enbridge Energy Partners, L.P. and its consolidated subsidiaries is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Exchange Act Rule 13a-15(f).

The Partnership's internal control over financial reporting is a process designed under the supervision and with the participation of our principal executive and principal financial officers to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Partnership's financial statements for external reporting purposes in accordance with U.S. generally accepted accounting principles.

The Partnership's internal control over financial reporting includes policies and procedures that:

- Pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets of the Partnership;
- Provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with U.S. generally accepted accounting principles, and that receipts and expenditures are being made only in accordance with the authorization of the Partnership's management and directors; and
- Provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of our assets that could have a material effect on our financial statements.

The Partnership's internal control over financial reporting may not prevent or detect all misstatements because of its inherent limitations. Additionally, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or deterioration in the degree of compliance with our policies and procedures.

Management assessed the effectiveness of the Partnership's internal control over financial reporting as of December 31, 2007, based on the framework established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment, management concluded that the Partnership maintained effective internal control over financial reporting as of December 31, 2007.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, has issued an attestation report on our internal control over financial reporting as of December 31, 2007, beginning on page F-2.

Changes in Internal Control Over Financial Reporting

No changes in our internal control over financial reporting were made during the three months ended December 31, 2007, that would materially affect our internal control over financial reporting.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The Partnership is a limited partnership and has no officers or directors of its own. Set forth below is certain information concerning the directors and executive officers of the General Partner and of Enbridge Management as the delegate of the General Partner under a Delegation of Control Agreement among the Partnership, the General Partner and Enbridge Management. All directors of the General Partner are elected annually and may be removed by Enbridge Pipelines, as the sole stockholder of the General Partner. All directors of Enbridge Management were elected and may be removed by the General Partner, as the sole holder of Enbridge Management's voting shares. All officers of the General Partner and Enbridge Management serve at the discretion of the respective boards of directors of the General Partner and Enbridge Management. All directors and officers of the General Partner hold identical positions in Enbridge Management.

Name	Age	Position
Directors and Executive Officers:		
M.O. Hesse	65	Director and Chairman of the Board
J.A. Connelly	61	Director
G.K. Petty	66	Director
D.A. Westbrook	55	Director
S.J.J. Letwin	52	Managing Director and Director
T.L. McGill	53	President and Director
S.J. Wuori	50	Executive Vice President—Liquids Pipelines and Director
Officers:		
R.L. Adams	43	Vice President—U.S. Engineering and Project Execution, Liquids Pipelines
E.C. Kaitson	51	Vice President—Law and Deputy General Counsel
D.V. Krenz	56	Vice President
J.A. Loiacono	45	Vice President—Commercial Activities
M.A. Maki	43	Vice President—Finance
A. Monaco	48	Executive Vice President—Major Projects
S.J. Neyland	40	Controller
K.C. Puckett	46	Vice President—Engineering and Operations, Gathering and Processing
J.N. Rose	40	Treasurer
A.M. Schneider	49	Vice President—Regulated Engineering and Operations, Gathering and Processing
B.A. Stevenson	52	Corporate Secretary
L.A. Zupan	52	Vice President—Liquids Pipelines Operations

M.O. Hesse was elected as Chairman of the Board in May 2007 and as a director of the General Partner and Enbridge Management in March 2003 and serves as a member of the Audit, Finance & Risk Committee. Ms. Hesse was President and Chief Executive Officer of Hesse Gas Company from 1990 through 2003. She served as Chairman of the U.S. Federal Energy Regulatory Commission from 1986 to 1989. Ms. Hesse also served as Senior Vice President, First Chicago Corporation and Assistant Secretary for Management and Administration, U.S. Department of Energy. She is a private investor and currently serves as a director of Amec plc, Mutual Trust Financial Group, and Terra Industries, Inc.

J.A. Connelly was elected a director of the General Partner and Enbridge Management in January 2003 and serves as the Chairman of the Audit, Finance & Risk Committee. Mr. Connelly served as Executive Vice President, Senior Vice President and Vice President of the Coastal Corporation from 1988 to 2001. Mr. Connelly is a business consultant providing executive management consulting services.

G.K. Petty was elected a director of the General Partner in February 2001 and Enbridge Management upon its formation and serves on the Audit, Finance & Risk Committee. Mr. Petty has served as a director of Enbridge since January 2001. Mr. Petty served as President and Chief Executive Officer of Telus Corporation, a Canadian telecommunications company, from November 1994 to November 1999. Mr. Petty retired in 1994 from AT&T Corporation as a Vice-President after 25 years of service. He currently serves on the Board of Directors of Fuelcell Energy Corporation.

D.A. Westbrook was elected a director of the General Partner and Enbridge Management in October 2007 and serves on the Audit, Finance & Risk Committee. From May 2007 he has also served on the Board of Directors of Synenco Energy Inc., where he is a member of their Audit & Risk and Finance Committees. From January 2006, he has served on the Board of Directors of Knowledge Systems Inc., a privately held U.S. company. From 2001 to 2005, Mr. Westbrook served as President of BP China Gas, Power & Upstream and Vice-Chairman of the Board of Directors of Dapeng LNG, a Sino joint venture between BP subsidiaries and other Chinese companies.

S.J.J. Letwin was elected Managing Director of the General Partner and Enbridge Management in May 2006, and is also Executive Vice President, Gas Transportation & International of Enbridge. Prior to his election he served Enbridge, the indirect parent of our General Partner, as Group Vice President, Gas Strategy & Corporate Development from April 2003; prior thereto he served Enbridge as Group Vice President, Distribution & Services from September 2000.

T. L. McGill was elected President of the General Partner and Enbridge Management in May 2006. Mr. McGill previously served as Vice President, Commercial Activity and Business Development of the General Partner and Enbridge Management from April 2002 and Chief Operating Officer from July 2004. Prior to that time, Mr. McGill was President of Columbia Gulf Transmission Company from January 1996 to March 2002.

S. J. Wuori was elected a director of the General Partner and Enbridge Management in January 2008 and is also the Executive Vice President of Liquids Pipelines for the General Partner and Enbridge Management. Mr. Wuori holds similar responsibilities with Enbridge. He was previously Executive Vice President, Chief Financial Officer and Corporate Development of Enbridge from 2006 to 2008, Group Vice President and Chief Financial Officer of Enbridge from 2003 to 2006 and Group Vice President, Corporate Planning and Development of Enbridge from 2001 to 2003.

R.L. Adams was elected Vice President, U.S. Engineering and Project Execution, Liquids Pipelines of the General Partner and Enbridge Management in June 2007 prior to which he was Vice President, Operations and Technologies from April 2003. Prior to April 2003, he was Director of Technology & Operations for the General Partner and Enbridge Management from 2001, and Director of Field Operations and Technical Services and Director of Commercial Activities for Ocensa/Enbridge in Bogota, Colombia from 1997 to 2001.

E.C. Kaitson was elected Vice President, Law and Deputy General Counsel of the General Partner and Enbridge Management in May 2007. He also currently serves as Deputy General Counsel of Enbridge. Prior to that he was Assistant Secretary of the General Partner and Enbridge Management from July 2004. He served as Corporate Secretary of the General Partner and Enbridge Management from October 2001 to July 2004. He was previously Assistant Corporate Secretary and General Counsel of Midcoast Energy Resources, Inc. from 1997 until acquired by Enbridge in May 2001.

D.V. Krenz was elected Vice President of the General Partner and Enbridge Management in January 2005. Prior to that, he was President of Shell Gas Transmission, LLC (previously Shell Gas Pipelines Co.) from March 1996 to December 2004.

J.A. Loiacono was elected Vice President, Commercial Activities, of the General Partner and Enbridge Management in July 2006. Prior to that, he was Director of Commercial Activities for the General Partner and Enbridge Management from April 2003 and commenced employment with Midcoast Energy Resources in February 2000 as an Asset Optimizer.

M.A. Maki was elected Vice President, Finance of the General Partner and Enbridge Management in July 2002. Prior to that time, he served as Controller of the General Partner and Enbridge Management from June 2001, and prior to that, as Controller of Enbridge Pipelines from September 1999.

A. Monaco was elected Executive Vice President, Major Projects of the General Partner and Enbridge Management in January 2008 and holds similar responsibilities with Enbridge. Prior to that Mr. Monaco was President of Enbridge Gas Distribution Inc. from September 2006, Senior Vice President, Planning & Development, Enbridge from June 2003, and Vice President, Financial Services, of Enbridge from February 2002. Mr. Monaco was Treasurer of the General Partner from February 2002 and Enbridge Management from its formation until his resignation in April 2003.

S.J. Neyland was elected Controller of the General Partner and Enbridge Management effective September 2006. Prior to his election he served as Controller, Natural gas from January 2005, Assistant Controller from May 2004 to January 2005, and in other managerial roles in Finance and Accounting from December 2001 to May 2004. Prior to that time, Mr. Neyland was Controller of Koch Midstream Services from 1999 to 2001.

K.C. Puckett was elected Vice President, Engineering and Operations, Gathering and Processing of the General Partner and Enbridge Management in October 2007. Prior to his election he served as General Manager of Engineering and Operations from 2004 and Manager of Operations from 2002 to 2004. Prior to that time, he served as Manager of Business Development for Sid Richardson Energy Services Company.

J. N. Rose was elected as Treasurer of the General Partner and Enbridge Management in January 2008. He was previously Assistant Treasurer of the General Partner and Enbridge Management from July 2005. Mr. Rose is also a Director, Finance of Enbridge, a position he has held from October 2007, prior to which he was Manager, Finance from 2004. Prior to that Mr. Rose was a Vice President with Citigroup Global Corporate and Investment Bank from 2001 to 2004.

A.M. Schneider was elected Vice President, Regulated Engineering and Operations of the General Partner and Enbridge Management in October 2007. Prior to his election he served as Director of Engineering and Operations for Regulated & Offshore and Director of Engineering Services from January 2005. Prior to that, Mr. Schneider was Vice President of Engineering and Operations for Shell Gas Transmission from December 2000.

B.A. Stevenson was elected Corporate Secretary of the General Partner and Enbridge Management in July 2004. Between 2000 and 2004 Mr. Stevenson held management positions with Reliant Energy, Inc. and Arthur Andersen LLP. Prior to that Mr. Stevenson was General Counsel & Corporate Secretary of Alberta Natural Gas Company Ltd, a Canadian gas processing and transmission company, that was acquired by TransCanada Pipelines.

L.A. Zupan was elected Vice President, Liquids Pipelines Operations of the General Partner and Enbridge Management in July 2004, and holds similar responsibilities with Enbridge. Mr. Zupan previously served as Vice President, Development & Services for Enbridge Pipelines from 2000.

SECTION 16(a) BENEFICIAL OWNERSHIP REPORTING COMPLIANCE

Section 16(a) of the Exchange Act requires our directors, executive officers and 10% beneficial owners to file with the SEC reports of ownership and changes in ownership of our equity securities and to furnish us with copies of all reports filed. To our knowledge, based solely on a review of the copies of reports furnished to us and written representations that no other reports were required, the officers, directors, and greater than 10% beneficial owners complied with all applicable filing requirements of Section 16(a) of the Exchange Act during the year.

GOVERNANCE MATTERS

We are a "controlled company," as that term is used in NYSE Rule 303A, because all of our voting shares are owned by the General Partner. Because we are a controlled company, the NYSE listing standards do not require that we or the General Partner have a majority of independent directors or a nominating or compensation committee of the General Partner's board of directors.

The NYSE listing standards require our Chief Executive Officer to annually certify that he is not aware of any violation by the Partnership of the NYSE corporate governance listing standards. Accordingly, this certification was provided as required to the NYSE on March 20, 2007.

CODE OF ETHICS, STATEMENT OF BUSINESS CONDUCT AND CORPORATE GOVERNANCE GUIDELINES

We have adopted a Code of Ethics applicable to our senior financial officers, including the principal executive officer, principal financial officer and principal accounting officer of Enbridge Management. A copy of the Code of Ethics for Senior Financial Officers is available on our website at *www.enbridgepartners.com* and is included herein as Exhibit 14.1. We post on our website any amendments to or waivers of our Code of Ethics for Senior Financial Officers. Additionally, this material is available in print, free of charge, to any person who requests the information. Persons wishing to obtain this printed material should submit a request to Corporate Secretary, c/o Enbridge Energy Partners, L.P., 1100 Louisiana, Suite 3300, Houston, TX 77002.

We also have a Statement of Business Conduct applicable to all of our employees, officers and directors. A copy of the Statement of Business Conduct is available on our website at *www.enbridgepartners.com*. We post on our website any amendments to or waivers of our Statement of Business Conduct. Additionally, this material is available in print, free of charge, to any person who requests the information. Persons wishing to obtain this printed material should submit a request to Corporate Secretary, c/o Enbridge Energy Partners, L.P., 1100 Louisiana, Suite 3300, Houston, TX 77002.

We also have a statement of Corporate Governance Guidelines that sets forth the expectation of how the Board should function and the Board's position with respect to key corporate governance issues. A copy of the Corporate Governance Guidelines is available on our website at *www.enbridgepartners.com*. We post on our website any amendments to our Corporate Governance Guidelines. Additionally, this material is available in print, free of charge, to any person who requests the information. Persons wishing to obtain this printed material should submit a request to Corporate Secretary, c/o Enbridge Energy Partners, L.P., 1100 Louisiana, Suite 3300, Houston, TX 77002.

AUDIT, FINANCE & RISK COMMITTEE

Enbridge Management has an Audit, Finance & Risk Committee (the "Audit Committee") comprised of four board members who are independent as the term is used in Section 10A of the Exchange Act. None of these members is relying upon any exemptions from the foregoing independence requirements. The members of the Audit Committee are J.A. Connelly, D.A. Westbrook, M.O. Hesse, and G.K. Petty. The Audit Committee provides independent oversight with respect to our internal controls, accounting policies, financial reporting, internal audit function and the report of the independent registered public accounting firm. The Audit Committee also reviews the scope and quality, including the independence and objectivity of the independent and internal auditors and the fees paid for both audit and non-audit work and makes recommendations concerning audit matters, including the engagement of the independent auditors, to the board of directors.

The charter of the Audit Committee is available on our website at *www.enbridgepartners.com*. The charter of the Audit Committee complies with the listing standards of the NYSE currently applicable to us. This material is available in print, free of charge, to any person who requests the information. Persons wishing to obtain this printed material should submit a request to Corporate Secretary, c/o Enbridge Energy Partners, L.P., 1100 Louisiana, Suite 3300, Houston, TX 77002.

Enbridge Management's board of directors has determined that J.A. Connelly and M.O. Hesse qualify as "Audit Committee financial experts" as defined in Item 407(d)(ii) of SEC Regulation S-K. Each of the members of the Audit, Finance and Risk Committee is independent as defined by Section 303A of the listing standards of the NYSE.

Ms. Hesse also serves on the Audit Committees of the General Partner, Enbridge Management, Amec plc., Mutual Trust Financial Group and of Terra Industries, Inc. In compliance with the provisions of the Audit, Finance & Risk Committee Charter, the boards of directors of the General Partner and of Enbridge Management have determined that Ms. Hesse's simultaneous service on such audit committees does not impair her ability to effectively serve on the Audit, Finance & Risk Committee.

Mr. Petty also serves on the Audit Committees of the General Partner, Enbridge Management, Fuel Cell Energy, Inc. and of Enbridge Inc. In compliance with the provisions of the Audit, Finance & Risk Committee Charter, the boards of directors of the General Partner and of Enbridge Management have determined that Mr. Petty's simultaneous service on such audit committees does not impair his ability to effectively serve on the Audit, Finance & Risk Committee.

Enbridge Management's Audit Committee has established procedures for the receipt, retention and treatment of complaints we receive regarding accounting, internal accounting controls or auditing matters and the confidential, anonymous submission by our employees of concerns regarding questionable accounting or auditing matters. Persons wishing to communicate with our Audit Committee may do so by writing in care of Chairman, Audit Committee, c/o Enbridge Energy Management, L.L.C., 1100 Louisiana, Suite 3300, Houston, TX 77002.

EXECUTIVE SESSIONS OF NON-MANAGEMENT DIRECTORS

The independent directors of Enbridge Management meet at regularly scheduled executive sessions without management. M.O. Hesse serves as the presiding director at those executive sessions. Persons wishing to communicate with the Company's independent directors may do so by writing in care of Chairman, Board of Directors, Enbridge Energy Partners, L.P., 1100 Louisiana, Suite 3300, Houston, TX 77002.

Item 11. Executive Compensation

COMPENSATION DISCUSSION AND ANALYSIS

We are a master limited partnership and we do not directly employ any of the individuals responsible for managing or operating our business nor do we have any directors. We obtain managerial, administrative and operational services from our general partner and Enbridge pursuant to service agreements among us, Enbridge Management, and affiliates of Enbridge. Pursuant to these service agreements, we have agreed to reimburse our general partner and affiliates of Enbridge for the cost of managerial, administrative, operational and director services they provide to us.

The compensation policies and philosophy of Enbridge govern the types and amount of compensation granted to each of the Named Executive Officers, or NEOs. Since these policies and philosophy are those of Enbridge, we refer you to a discussion of those items as set forth in the Executive Compensation section of the Enbridge "Management Information Circular" on the Enbridge website at www.enbridge.com. The Enbridge "Management Information Circular" is produced by Enbridge pursuant to Canadian securities regulations and is not incorporated into this document by reference or deemed furnished or filed by us under the Exchange Act; rather the reference is to provide our investors with an understanding of the compensation policies and philosophy of the ultimate parent of our general partner.

The boards of directors of Enbridge Management and our General Partner do not have separate compensation committees, nor do they have responsibility for approving the elements of compensation presented in the tables which follow this discussion. The boards of directors of Enbridge Management and our general partner do have responsibility for evaluating and determining the reasonableness of the total amount we are charged for managerial, administrative and operational support, including compensation of the NEOs, provided by Enbridge and its affiliates, including our general partner.

All U.S.-domiciled employees of Enbridge are directly employed by its subsidiary, Enbridge Employee Services, Inc., which we refer to as EES. In connection with our annual budget process, we calculate an average "Budgeted Allocation Rate," which represents an estimated average of the percentage of time expected will be spent by each of our NEOs on our business during the succeeding year. Those estimates are revised each year based on historical experience. The average Budgeted Allocation Rate was 84% for 2007 and has been set at approximately 85% for 2008. EES' salary costs are allocated to us based on the percentage of time spent by EES employees on our behalf compared with the total time of all EES employees. We are allocated a portion of the equity-based compensation expense as determined in accordance with U.S. GAAP. Pension expenses of EES (other than expenses under Enbridge's nonqualified supplemental pension plan for U.S.-domiciled employees, which we refer to as the SPP) are allocated to us based on the proportion that the total headcount of EES employees assigned to us bears to the total headcount of EES. For this purpose, an employee of EES is deemed to be assigned to us if he or she works on assets we own. Pension expenses of EES attributable to the SPP are allocated to us based upon the average Budgeted Allocation Rate. EES allocates to us that portion of its compensation expense for Enbridge's Short Term Incentive Plan, a non-equity performance-based incentive plan, equal to the total salaries of employees who perform work for us multiplied by the average Budgeted Allocation Rate divided by EES' total salary expense.

We are a partnership and not a corporation for U.S. federal income tax purposes, and therefore, are not subject to the executive compensation tax deductible limitations of Internal Revenue Code §162(m). Accordingly, none of the compensation paid to our NEOs is subject to limitation. The compensation of our Named Executive Officers included in the tables below is established by a committee of the board of directors of Enbridge. We have included in the following tables the full amount of compensation and related benefits provided for the NEOs for 2007 and 2006, together with the approximate amount of compensation cost allocated to us for the years ended December 31, 2007 and 2006.

SUMMARY COMPENSATION TABLE

Name and Principal Position	Year	Salary ($)	Bonus ($)	Stock Awards[1] ($)	Option Awards[2] ($)	Non-Equity Incentive Plan Compensation[3] ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)	All Other Compensation[4] ($)	Total ($)	Approximate Amount Allocated to Enbridge Energy Partners, L.P. ($)
S.J.J. Letwin[5] Managing Director *(Principal Executive Officer)*	2007	483,750	—	116,820	570,647	450,000	335,000	127,310	2,083,527	$ 1,507,502
	2006	457,257	—	108,600	316,259	450,000	208,000	185,871	1,725,987	—
T.L. McGill President	2007	323,631	—	41,536	148,725	241,320	128,000	50,039	933,251	815,977
	2006	290,000	—	38,535	191,599	200,000	103,000	39,659	862,793	758,806
J. R. Bird[6] Executive Vice President–Liquids Pipelines	2007	468,692	—	116,820	476,614	465,203	988,000	88,167	2,603,496	269,386
	2006	419,937	—	98,090	495,433	440,878	512,000	75,042	2,041,380	190,000
M.A. Maki Vice President–Finance *(Principal Financial Officer)*	2007	258,681	—	27,258	67,217	161,170	103,000	38,856	656,182	577,011
	2006	212,500	—	22,187	74,014	140,000	71,000	35,056	554,757	480,703
R.L. Adams Vice President–Operations and Technology	2007	220,779	—	22,066	53,895	135,000	78,000	96,469	606,209	564,365
	2006	189,375	—	19,852	50,677	117,000	55,000	33,543	465,447	402,909

(1) The 2007 expense associated with Performance Stock Units (PSUs) is reflected in this column and is measured based on the number of respective units granted, the percentage vested (33%) and the market value, representing the volume weighted average closing price of an Enbridge share as quoted on the NYSE for U.S. dollar (USD) denominated PSUs and the Toronto Stock Exchange, or TSX, for Canadian dollar (CAD) denominated PSUs for the 20 consecutive days prior to January 1, 2008. Beginning in 2007, U.S. domiciled NEOs were granted PSUs denominated in USD with a market value at December 31, 2007 of $38.94 per unit computed as described in the preceding sentence. Canadian domiciled NEOs are granted PSUs denominated in CAD, the market value of the 2007 PSUs has been converted to USD at December 31, 2007 using the market value computed for U.S. domiciled employees. The 2006 expense for PSUs grants is measured based on the number of respective units granted, the percentage vested (33%) and the market value, representing the weighted average closing price of an Enbridge share as quoted on the Toronto Stock Exchange, or TSX for the 20 consecutive days prior to January 1, 2007, or $39.73 CAD, since all 2006 PSU grants are denominated in CAD. The expense has been converted to United States dollars, or USD, using the average exchange rate during 2006 of $1.1341 CAD = $1 USD. The PSUs were granted on January 1, 2007 and 2006, respectively.

(2) The annual expenses for option awards that are granted under the Enbridge Incentive Stock Option Plan (2002) ("ISOP") and the Performance Stock Option Plan (2007) ("PSOP") are determined by computing the fair value of the options under FAS 123(R) on the grant date using the Black-Scholes option pricing model with the following assumptions for the indicated grant year:

	ISOP		PSOP	
Assumption	**2007**	**2006**	**2007**	**2006**
Expected option term in years	6	8	8	NA
Expected volatility	18.1%	19.0%	13.6%	NA
Expected dividend yield	3.22%	3.23%	3.57%	NA
Risk-free interest rate	4.11%	4.16%	4.38%	NA

The fair value of ISOPs granted as computed using the above assumptions is expensed over the shorter of the vesting period for the options or the period in which an NEO is within three years of attaining eligibility for early retirement. In 2006, Mr. McGill and in 2007 Mr. Letwin reached the period where they were within three years of attaining eligibility for early retirement and Mr. Bird is currently eligible for early retirement. Accordingly, the amounts reported in this column for each of these individuals include 100 percent of the fair value of the ISOPs they were granted for the respective periods, although vesting is not accelerated. The fair value of PSOPs granted as computed using the above assumptions is expensed over the vesting period for the options, generally five years. The exercise price and fair value information for all option grants has been converted to United States dollars using the exchange rates as set forth in the tables below. The fair values of all grants on the grant date has been converted to USD using the average exchange rates, representing the exchange rate for the period during which the expense was recognized.

	ISOP		PSOP	
	2007	2006	2007	2006
Exercise price in CAD	$ 38.26	$ 36.47	$ 36.57	NA
Exercise price in USD	$ 32.59	$ 31.58	$ 34.03	NA
Grant date exchange rate for $1 USD	$ 1.1740	$ 1.1548	$ 1.0746	NA

	ISOP		PSOP	
	2007	2006	2007	2006
Vesting period	4	4	5	NA
Option fair value on grant date in CAD	$ 6.16	$ 6.28	$ 3.40	NA
Option fair value on grant date in USD	$ 5.25	$ 5.54	$ 3.16	NA
Average exchange rate for $1 USD	$ 1.1740	$ 1.1341	$ 1.0750	NA

(3) Non-equity incentive plan compensation represents awards that are paid in February for amounts that are earned in the immediately preceding fiscal year under the Enbridge Short Term Incentive Plan, or STIP. The Enbridge STIP is a performance-based plan where measurement metrics are established at the beginning of each fiscal year that promote the achievement of financial, safety, corporate governance and individual goals. The amount presented for Mr. Bird represents an award of $500,000 CAD, which was converted to USD using the weighted average exchange rate of $1.0748 CAD = $1 USD. All other amounts presented in this column represent USD denominated STIP awards.

(4) The table which follows labeled "All Other Compensation" sets forth the elements comprising the amounts presented in this column.

(5) Mr. Letwin relocated to the United States on May 1, 2006, and became Managing Director of our general partner and Enbridge Management. Mr. Letwin is also an executive officer of Enbridge with responsibility for other Enbridge operations in addition to those of our general partner, Enbridge Management, and us, which he assumed in May 2006. We have included the full amount of Mr. Letwin's compensation in the summary compensation table. However, we were not charged the cost of Mr. Letwin's compensation for the period from January 1, 2006 through December 31, 2006, since the allocation to us of compensation to Mr. Letwin was not contemplated in our budget. As a result, Mr. Letwin's compensation was borne by other Enbridge affiliates. For the year ended December 31, 2006, we used a weighted average exchange rate of $1.1519 CAD = $1 USD to convert the compensation costs to USD for Mr. Letwin, which represents the weighted average exchange rate for the period from May 1, 2006 through December 31, 2006. The costs associated with the PSU's and options Mr. Letwin was granted in 2006 were borne by Enbridge and other affiliates where he is also an officer because the grants occurred prior to his becoming managing director of our general partner and Enbridge Management.

(6) Mr. Bird is also an executive officer of Enbridge with responsibility for other affiliates of Enbridge in addition to those for our general partner and Enbridge Management. Mr. Bird is compensated by affiliates of Enbridge in CAD which we have converted to USD using the weighted average exchange rates for the years ended December 31, 2007 and 2006 of $1.0748 CAD = $1 USD and $1.1341 CAD = $1.0 USD, respectively. The costs associated with the PSU's and options Mr. Bird was granted in 2007 and 2006 were borne by Enbridge and other affiliates where he is also an officer. We are allocated a portion of the remaining elements of Mr. Bird's compensation based on the approximate percentage of time he devotes to us and Enbridge Management. In January 2008, Mr. Bird assumed other responsibilities with Enbridge and ceased being an NEO of Enbridge Management and the General Partner.

ALL OTHER COMPENSATION
(For the years ended December 31, 2007 and 2006)

Name	Year	Flexible Benefits(1)	401(k) Matching Contribution(2)	Relocation Allowance	Mortgage Interest Payments	Dividends Paid on PSUs	Other Benefits(3)	Total
S.J.J. Letwin	2007	$ 35,000	$ 11,250	$ —	$ 40,321	$ 36,307	$ 4,432	$ 127,310
	2006	35,169	11,000	77,500	25,701	29,706	6,795	185,871
T.L. McGill	2007	20,000	11,250	—	—	11,204	7,585	50,039
	2006	20,000	11,000	—	—	6,434	2,225	39,659
J.R. Bird	2007	52,081	—	—	—	32,045	4,041	88,167
	2006	48,482	—	—	—	24,236	2,324	75,042
M.A. Maki	2007	20,000	11,250	—	—	7,343	263	38,856
	2006	20,000	10,625	—	—	4,214	217	35,056
R.L. Adams	2007	20,000	11,039	58,722	—	6,493	215	96,469
	2006	20,000	9,469	—	—	3,882	192	33,543

(1) Flexible benefits for our U.S. domiciled NEOs represent a perquisite allowance that is paid in cash as additional compensation. Our NEOs domiciled in Canada receive flexible benefits based on their family status and base salary. For our NEOs that are domiciled in Canada, the flexible benefits can be used to purchase additional benefits, paid in cash, or be applied as contributions to the Enbridge Stock Purchase and Savings Plan; or (b) paid as additional compensation. The amounts reported in this column include the net flexible benefits that Mr. Bird and Mr. Letwin (2006) applied to the Enbridge Stock Purchase and Savings Plan.

(2) Our NEOs that are domiciled in the United States and participate in the Enbridge Employee Services, Inc. Savings Plan (the "401(k) Plan") may contribute up to 50 percent of their base salary which is matched up to 5 percent by Enbridge. Both individual and matching contributions are subject to limits established by the Internal Revenue Service. Enbridge contributions are used to purchase Enbridge shares at market value and employee contributions may be used to purchase Enbridge shares or 22 designated funds.

(3) Other benefits include professional financial services, term life insurance premiums, parking, and home security and internet services.

We do not maintain any compensation plans for the benefit of the NEOs under which equity interests in Enbridge Management or the Partnership may be awarded. However, Enbridge allocates to us the compensation expense it recognizes under FAS 123(R) in connection with recording the fair value of its restricted stock units and outstanding stock options granted to certain of our officers, including the NEOs. The costs we are charged with respect to option grants represent a portion of the costs determined in accordance with U.S. GAAP.

The performance stock units are granted to the NEOs pursuant to the Enbridge Inc. Performance Stock Unit Plan and stock options are granted pursuant to the Enbridge Incentive Stock Option Plan (2002) and the Performance Stock Option Plan (2007). Awards under these plans provide long-term incentive and are administered by the Human Resources & Compensation Committee of Enbridge. The performance stock units granted from 2004 through 2006 and stock option grants are denominated in CAD. The performance stock units granted in 2007 to our U.S.-domiciled NEOs are denominated in USD while those granted to NEOs domiciled in Canada are denominated in Canadian dollars. The following two tables set forth information concerning performance stock units and stock options outstanding at

December 31, 2007, and the number of awards vested and exercised during the year ended December 31, 2007, by each of the NEOs:

GRANTS OF PLAN-BASED AWARDS

				Estimated Future Payouts Under non-Equity Incentive Plan Awards[4]			Estimated Future Payouts Under Equity Incentive Plan Awards[2]						
Name (a)	Plan Name[1]	Approval Date (b)	Grant Date (b)	Threshold ($) (c)	Target ($) (d)	Maximum ($) (e)	Threshold (#) (f)	Target (#) (g)	Maximum (#) (h)	All Other Stock Awards: Number of Shares of Stock or Units (#) (i)	All Other Option Awards: Number of Securities Underlying Options[3] (#) (j)	Exercise or Base Price of Option Awards[3] ($/Sh) (k)	Grant Date Fair Value of Stock and Option Awards [2][3] ($) (l)
S.J.J. Letwin	PSUP	30-Jan-07	1-Jan-07	—	—	—	360	9,000	18,000	—	—	—	312,570
	ISOP	30-Jan-07	9-Feb-07	—	—	—	—	—	—	—	45,000	32.59	236,250
	PSOP	31-Jul-07	15-Aug-07	—	—	—				—	330,000	34.03	1,044,109
	STIP	30-Jan-07	28-Feb-07	—	245,000	490,000	—	—	—	—	—	—	—
T.L. McGill	PSUP	30-Jan-07	1-Jan-07	—	—	—	128	3,200	6,400	—	—	—	111,136
	ISOP	30-Jan-07	9-Feb-07	—	—	—	—	—	—	—	16,400	32.59	86,100
	STIP	30-Jan-07	28-Feb-07	—	127,680	255,360	—	—	—	—	—	—	—
J.R. Bird	PSUP	30-Jan-07	1-Jan-07	—	—	—	360	9,000	18,000	—	—	—	312,570
	ISOP	30-Jan-07	9-Feb-07	—	—	—	—	—	—	—	45,000	32.59	236,250
	PSOP	31-Jul-07	15-Aug-07	—	—	—	—	—	—	—	330,000	34.03	1,044,109
	STIP	30-Jan-07	28-Feb-07	—	237,253	474,507	—	—	—	—	—	—	—
M.A. Maki	PSUP	30-Jan-07	1-Jan-07	—	—	—	84	2,100	4,200	—	—	—	72,933
	ISOP	30-Jan-07	9-Feb-07	—	—	—	—	—	—	—	11,500	32.59	60,375
	STIP	30-Jan-07	28-Feb-07	—	88,410	176,820	—	—	—	—	—	—	—
R.L. Adams	PSUP	30-Jan-07	1-Jan-07	—	—	—	68	1,700	3,400	—	—	—	59,041
	ISOP	30-Jan-07	9-Feb-07	—	—	—	—	—	—	—	9,500	32.59	49,875
	STIP	30-Jan-07	28-Feb-07	—	78,750	157,500	—	—	—	—	—	—	—

(1) The abbreviated plan names are defined as follows:

a. PSUP refers to the Enbridge Performance Stock Unit Plan, an equity-based incentive plan.

b. ISOP refers to the Enbridge Incentive Stock Option Plan, a qualified stock option plan.

c. PSOP refers to the Enbridge Performance Stock Option Plan (2007), a performance-based, incentive stock option plan.

d. STIP refers to the Enbridge Short Term Incentive Plan, a non-equity performance-based incentive plan.

(2) Our NEOs are eligible to receive annual grants of Performance Stock Units, or PSUs, under the Performance Stock Unit Plan, or PSUP, an equity-based, long-term incentive plan, administered by a committee of the board of directors of Enbridge. The initial value of each of these PSUs on the grant date is equivalent to the weighted average closing price of one Enbridge share as quoted on the New York Stock Exchange for the 20 days immediately preceding the start of the performance period. The initial PSUs granted are increased for quarterly dividends paid during the three-year period on an Enbridge share. Awards under the 2007 PSUP are paid out in cash at the end of a three-year performance cycle based on: (1) an earnings per share, or EPS target for Enbridge based on the long range plan of the organization and (2) the price to earnings ratio of an Enbridge share relative to a defined group of peer organizations established in advance by a committee of the board of directors of Enbridge. The performance measures for grants awarded from 2004 through 2006 are based on (1) the market value of an Enbridge share at the end of the three-year period; and (2) the total shareholder return for Enbridge over a three-year period in relation to a peer group of companies established in advance by a committee of the board of directors of Enbridge. Payments under the PSUP may be increased up to 200 percent of the original award when Enbridge outperforms its peer group. If Enbridge fails to meet threshold performance levels, no payments are made under the PSUP. Dividends are paid on the PSUs which are invested in additional PSUs at the then current market price for one share of Enbridge common stock which are not included in the estimated future payout amounts, but have been included as other compensation in the Summary Compensation table. Enbridge does not issue any shares in connection with the PSUP.

The threshold at which PSUs are issued represents 4 percent of the number of PSUs initially granted and is the lowest level at which PSUs will be issued based on the performance criteria discussed above. The target level at which PSUs are issued represents 100 percent of the number of PSUs initially granted and attainment of the established performance criteria. The maximum level at which PSUs may be issued is 200 percent of the number of PSUs initially granted and may occur when Enbridge exceeds the established performance criteria.

PSUs vest at the end of a three year performance period that begins on January 1 of the year granted and during the term the PSUs are outstanding, a liability and expense are recorded by Enbridge based on the number of PSUs outstanding and the current market price of an Enbridge share. The grant date fair value for each PSU granted to each of our NEOs in 2007 was

$34.73 USD, representing the weighted average closing price of one Enbridge share as quoted on the New York Stock Exchange for the 20 days immediately preceding the start of the performance period that began on January 1, 2007.

(3) The Enbridge Incentive Stock Option Plan (2002) is administered by a committee of the Enbridge board of directors and if an option is issued during a trading blackout period, the exercise price of an option grant is determined as the weighted average trading price of an Enbridge share on the Toronto Stock Exchange for the three trading days immediately prior to the effective date of the option. In the event an option grant is issued during a period a trading blackout is not in effect, the exercise price of the option grant is equal to the last reported sales price on the Toronto Stock Exchange for the day immediately preceding the grant date. During 2007, each of the NEOs received grants of Enbridge incentive stock options that upon exercise may be exchanged for an equivalent number of shares of Enbridge common stock. The exercise price of the incentive stock options at the time of grant was $38.26 CAD which has been converted into USD using an exchange rate of $1.1740 CAD per $1 USD, representing the noon buying rate in New York for transfers of CAD on the grant date of February 9, 2007.

The amounts included as the grant date fair value for the 2007 incentive stock option awards represent the amount determined by computing the fair value of the options under FAS 123(R) on the grant date using the Black-Scholes option pricing model with the following assumptions:

- 6 years expected term;
- 18.1% expected volatility;
- 3.22% expected dividend yield; and
- 4.11% risk free interest rate

The fair value of options granted as computed using these assumptions is $6.16 CAD which has been converted to USD using an exchange rate of $1.0750 CAD = $1 USD which equates to a grant date fair value of $5.25 USD per option granted. The grant date fair value is expensed over the shorter of the vesting period for the options (generally 4 years) and the period to early retirement eligibility.

(4) The Enbridge Performance Stock Option Plan (2007) is administered by a committee of the Enbridge board of directors and if an option is issued during a trading blackout period, the exercise price of an option grant is determined as the weighted average trading price of an Enbridge share on the Toronto Stock Exchange for the five trading days immediately prior to the effective date of the option. In the event an option grant is issued during a period a trading blackout is not in effect, the exercise price of the option grant is equal to the last reported sales price on the Toronto Stock Exchange for the day immediately preceding the grant date. Performance-based stock options, or PBSOs, are similar to the incentive stock options, except that the quantities become exercisable subject to both the achievement of specified share price targets and time requirements. One half of the PBSOs become exercisable if the first share price hurdle is achieved and 100% of the grant becomes exercisable if the second share price hurdle is achieved within a $6^{1}/2$ year time period. The term of each grant is 8 years provided the performance criteria are met. PBSOs are granted on an infrequent basis and provide the eligible NEO the opportunity to acquire one Enbridge Share for each option held when the specified time and share price targets are met. During 2007, Messrs. Letwin and Bird each received grants of Enbridge performance stock options that upon exercise may be exchanged for an equivalent number of shares of Enbridge common stock. The exercise price of the PBSOs at the time of grant was $36.57 CAD which has been converted into USD using an exchange rate of $1.0746 CAD per $1 USD, representing the noon buying rate in New York for transfers of CAD on the grant date of August 15, 2007.

The amounts included as the grant date fair value for the 2007 PBSO awards represent the amount determined by computing the fair value of the options under FAS 123(R) on the grant date using the Black-Scholes option pricing model with the following assumptions:

- 8 years expected term;
- 13.6% expected volatility;
- 3.57% expected dividend yield; and
- 4.38% risk free interest rate

The fair value of options granted as computed using these assumptions is $3.40 CAD which has been converted to USD using an exchange rate of $1.0748 CAD = $1 USD which equates to a grant date fair value of $3.16 USD per option granted. The grant date fair value is expensed over the vesting period for the options, generally 5 years.

(5) The estimated future payouts under the Enbridge STIP are determined for the indicated fiscal year, based upon achievement of performance goals established at the beginning of the fiscal year for each of the NEOs. The payouts earned under the STIP for each fiscal year are generally paid to the NEO on the last business day of February of the year following the fiscal year in which the payout is earned. The performance goals include pre-determined financial, safety, corporate governance and operational goals that are aligned with the business objectives for Enbridge and the business unit(s) to which the NEOs are assigned, in addition to individual performance objectives. Based upon the level achieved in meeting the pre-determined objectives, a multiple is determined that can vary from a low of zero, if the level of achievement is significantly below the stated objectives, to a high of two, if the level of achievement significantly exceeds the stated objective, with the mid-point or target representing achievement of 100 percent of the pre-established goals. The multiple is then applied to the bonus level, represented as a percentage of base salary, for each NEO. The STIP targets for each NEO expressed as a percentage of salary for 2007 is as follows:

	Threshold	**Target**	**Maximum**
S.J.J. Letwin	—	50%	100%
T.L. McGill	—	40%	80%
J.R. Bird	—	50%	100%
M.A. Maki	—	35%	70%
R.L. Adams	—	35%	70%

OUTSTANDING EQUITY AWARDS AT FISCAL YEAR END

	Option Awards					Stock Awards			
Name (a)	Number of Securities Underlying Unexercised Options (#) Exercisable (b)	Number of Securities Underlying Unexercised Options (#) Unexercisable (1)(2) (c)	Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options (#) (d)	Option Exercise Price(4) ($) (e)	Option Expiration Date(1) (f)	Number of Shares or Units of Stock That Have Not Vested (#) (g)	Market Value of Shares or Units of Stock That Have Not Vested ($) (h)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested(3) (#) (i)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($) (j)
S.J.J. Letwin	—	11,000	—	19.30	4-Feb-14	—	—	9,921	401,117
	26,200	26,200	—	25.49	3-Feb-15	—	—	9,304	376,159
	—	330,000	—	34.03	15-Aug-15				
	13,425	40,275	—	31.58	13-Feb-16				
	—	45,000	—	32.59	9-Feb-17				
T.L. McGill	46,400	—	—	13.69	6-Feb-13	—	—	3,520	142,332
	30,000	10,000	—	19.30	4-Feb-14	—	—	3,308	133,746
	10,200	10,200	—	25.49	3-Feb-15				
	4,725	14,175	—	31.58	13-Feb-16				
	—	16,400	—	32.59	9-Feb-17				
J.R. Bird	200,000[2]	—	—	14.63	16-Sep-10	—	—	8,961	362,300
	40,000	—	—	13.69	6-Feb-13	—	—	9,304	376,176
	25,050	8,350	—	19.30	4-Feb-14				
	20,700	20,700	—	25.49	3-Feb-15				
	—	330,000	—	34.03	15-Aug-15				
	12,075	36,225	—	31.58	13-Feb-16				
	—	45,000	—	32.59	9-Feb-17				
M.A. Maki	7,500	—	—	12.43	21-Feb-11	—	—	2,027	81,949
	16,000	—	—	13.68	5-Feb-12	—	—	2,171	87,771
	33,400	—	—	13.69	6-Feb-13				
	22,500	7,500	—	19.30	4-Feb-14				
	5,700	5,700	—	25.49	3-Feb-15				
	2,775	8,325	—	31.58	13-Feb-16				
	—	11,500	—	32.59	9-Feb-17				
R.L. Adams	4,500	—	—	13.69	6-Feb-13	—	—	1,814	73,323
	10,000	5,000	—	19.30	4-Feb-14	—	—	1,757	71,052
	5,400	5,400	—	25.49	3-Feb-15				
	2,500	7,500	—	31.58	13-Feb-16				
	—	9,500	—	32.59	9-Feb-17				

(1) Each incentive stock option award has a ten year term and vests pro rata as to one-fourth of the option award beginning on the first anniversary of the grant date thus, the vesting dates for each of the option awards in this table can be calculated accordingly. As an example, for Mr. Letwin's grant that expires on February 6, 2013, the grant date would be ten years prior or February 6, 2003 and as a result, the remaining unexercisable amounts become fully vested on February 6, 2007 representing four years following the grant date.

(2) Performance-based stock options, or PBSOs, were provided to certain of our NEOs on September 16, 2002 and August 15, 2007 and are similar to the incentive stock options, except that the quantity that become exercisable are subject to both time and performance requirements. PBSOs are granted on an infrequent basis and provide the eligible NEO the opportunity to acquire one Enbridge Share for each option held when the specified time and performance conditions are met. The PBSOs granted September 16, 2002, became exercisable, as to 50 percent of the grant, when the price of an Enbridge Share exceeded $30.50 for 20 consecutive trading days during the period September 16, 2002 to September 16, 2007, and became exercisable as to 100 percent when the price of an Enbridge share exceeded $35.50 CAD for 20 consecutive trading days during the same period. As a result of achieving the established performance criteria, the initial five year term of the options was extended to eight years expiring on September 16, 2010. In addition to the performance hurdles, the PBSOs are also time vested 20% annually over 5 years. As of December 31, 2007, 100 percent of the PBSOs granted September 16, 2002, had vested and were exercisable and none of the PBSOs granted August 15, 2007, were vested or exercisable.

(3) The unearned shares, units or other rights that have not vested under stock awards represent PSUs for which the performance criteria discussed in footnote number 2 of the Grants of Plan-Based Awards table have not been achieved. The PSUs become vested upon achieving the established performance criteria as set forth in the aforementioned footnote.

(4) The exercise prices of the ISDs and PBSOs are denominated in CAD, which have been converted to USD using the exchange rate on the grant date as set forth below:

Option Grant Date	Option Exercise Price CAD	Exchange Rate USD/CAD	Option Exercise Price USD
February 21, 2001	$ 19.1000	$ 0.6508	$ 12.4303
February 5, 2002	21.8500	0.6259	13.6759
September 16, 2002	23.1500	0.6319	14.6285
February 6, 2003	20.8250	0.6572	13.6862
February 4, 2004	25.7200	0.7504	19.3003
February 3, 2005	31.6800	0.8046	25.4897
February 13, 2006	36.4700	0.8660	31.5830
February 9, 2007	38.2600	0.8519	32.5937
August 15, 2007	36.5700	0.9306	34.0320

OPTION EXERCISES AND STOCK VESTED

	Option Awards		Stock Awards	
Name	Number of Shares Acquired on Exercise (#)	Value Realized on Exercise ($)	Number of Shares Acquired on Vesting(1) (#)	Value Realized on Vesting(2) ($)
S.J.J. Letwin	71,000	955,832.74	20,702.32	$ 392,467.47
T.L. McGill	—	—	3,166.67	89,124.18
J.R. Bird	—	—	16,038.10	307,147.03
M.A. Maki	—	—	2,353.01	66,224.21
R.L. Adams	—	—	2,221.07	62,510.71

(1) The number of shares acquired on vesting represent the number of PSUs issued in 2004 that matured on March 7, 2007, and in 2005 that matured on December 31, 2007. As discussed above in footnote number 2 of the Grants of Plan-Based Awards table, no shares are issued with respect to the PSUs that become vested rather cash is paid in an amount based on the value of an Enbridge share at the maturity date and the level of achievement of the established performance goals.

(2) The value realized on vesting has been converted to USD using an exchange rate of $1.1786 CAD = $1 USD for the PSUs that matured on March 7, 2007, and an exchange rate of $0.9881 CAD = $1 USD for the PSUs that matured on December 31, 2007. These exchange rates represent the noon buying rate in New York for transfers of CAD on the respective maturity dates.

(3) The value realized on exercise of options by Mr. Letwin has been converted to USD using an exchange rate of $0.9818 CAD = $1 USD for 40,000 options exercised on October 5, 2007 and an exchange rate of $1.0194 CAD = $1 USD for 31,000 options exercised on September 18, 2007.

Pension Plan

Enbridge sponsors two basic pension plans, the Retirement Plan for Employees' Annuity Plan ("EI RPP") and the Enbridge Employee Services, Inc. Employees' Annuity Plan ("QPP"), which provide defined pension benefits and cover employees in Canada and the United States, respectively. Both plans are non-contributory. Enbridge also sponsors supplemental nonqualified retirement plans in both Canada ("EI SPP") and the United States ("US SPP"), which provide pension benefits for the NEOs in excess of the tax-qualified plans' limits. We collectively refer to the EI RPP, the QPP, the EI SPP and the US SPP as the "Pension Plans." Retirement benefits under the Pension Plans are based on the employees' years of service and final average remuneration with an offset for Social Security benefits. These benefits are partially indexed to inflation after a named executive officer's retirement.

For service prior to January 1, 2000, the Pension Plans provide a yearly pension payable after age 60 in the normal form (60 percent joint and last survivor) equal to: (a) 1.6 percent of the average of the participant's highest annual salary during three consecutive years out of the last ten years of credited service multiplied by (b) the number of credited years of service. The pension is offset, after age 65, by 50 percent of the participant's Social Security benefit, prorated by years in which the participant has both

credited service and Social Security coverage. An unreduced pension is payable if retirement is after age 55 with 30 or more years of service, or after age 60. Early retirement reductions apply if a participant retires and does not meet these requirements. Retirement benefits paid from the Plan are indexed at 50 percent of the annual increase in the consumer price index.

For service after December 31, 1999, the Pension Plans provide for senior management employees, including the NEOs, a yearly pension payable after age 60 in the normal form (60 percent joint and last survivor) equal to: (a) 2 percent of the sum of (i) the average of the participant's highest annual base salary during three consecutive years out of the last ten years of credited service and (ii) the average of the participant's three highest annual performance bonus periods, represented in each period by 50 percent of the actual bonus paid, in respect of the last five years of credited service, multiplied by (b) the number of credited years of service. An unreduced pension is payable if retirement is after age 55 with 30 or more years of service, or after age 60. Early retirement reductions apply if a participant retires and does not meet these requirements. Retirement benefits paid from the Plan are indexed at 50 percent of the annual increase in the consumer price index.

The table illustrates the total annual pension entitlements assuming the eligibility requirements for an unreduced pension have been satisfied. The present value of the accumulated benefits has been determined under the accrued benefit valuation method with the following assumptions:

Discount rate	6.00% at year end 2007
Salaries	Current
Inflation	2.50% per year
Retirement age	60
Terminations	None
Mortality	
Pre-retirement	None
Post-retirement	RP-2000 Projected to 2005

Plan benefits that exceed maximum pension rules applicable to registered plan benefits are paid from the Enbridge supplemental pension plans. Other trusteed pension plans, with varying contribution formulae and benefits, cover the balance of employees.

Mr. Bird accumulated pension credits equal to 2.0% for each year of service from his date of employment until January 1, 2000 and 3.26% for each year of service thereafter to his sixtieth birthday. Mr. Letwin was granted six additional years of credited service on his employment date based on the pension formula applicable for service prior to January 1, 2000.

PENSION BENEFITS

Name (a)	Plan Name (b)	Number Of Years Credited Service (#) (c)	Present Value of Accumulated Benefit ($) (d)	Payments During Last Fiscal Year ($) (e)
S.J.J. Letwin	EI RPP	7.08	177,000	—
	EI SPP	13.08	1,460,000	—
	QPP	1.67	63,000	—
	USSPP	1.67	163,000	—
T.L. McGill	US QPP	5.50	90,000	—
	US SPP	5.83	389,000	—
J.R. Bird	EI RPP	12.92	431,000	—
	EI SPP	12.92	3,120,000	—
M.A. Maki	EI RPP	1.92	32,000	—
	EI SPP	1.92	36,000	—
	US QPP	19.40	462,000	—
	US SPP	19.40	100,000	—
R.L. Adams	US QPP	20.58	451,000	—
	US SPP	6.50	85,000	—

Employment and Severance Agreements

Enbridge has employment and severance agreements in place with each of Stephen J. J. Letwin, Managing Director and Chief Executive Officer of Enbridge Management and the General Partner, and J. Richard Bird, Executive Vice President—Liquids Pipelines of Enbridge Management and the General Partner. The agreements took effect on April 14, 2003 and were amended effective June 24, 2004. The agreements continue in effect until the earlier of (i) the applicable executive's voluntary retirement in accordance with the retirement policies established for senior employees of Enbridge, (ii) such executive's voluntary resignation, other than a voluntary resignation within 90 days after a "constructive dismissal" (as defined in the agreements) or within one year following a change of control of Enbridge, (iii) termination based on death or disability of such executive, or (iv) termination of such executive's employment by Enbridge.

The agreements provide that Enbridge will pay severance benefits to each of Mr. Letwin and Mr. Bird if (i) his employment is involuntarily terminated without cause or because of his disability, (ii) he elects to terminate his employment within 60 days of the first anniversary of the occurrence of a change of control of Enbridge, or (iii) he elects to terminate his employment within 60 days following constructive dismissal. In each such instance, and subject to the terms of the agreements, Enbridge will pay to the applicable executive the following:

(a) A lump sum payment equal to two times the sum of: (i) twelve times the gross monthly salary paid to him in the last full month of employment and (ii) the average of the last two years of the Enbridge Short Term Incentive Plan (STIP) awards paid to him;

(b) A lump sum payment equal to two times the cash value of the last annual flex benefit credit allowance provided to him under Enbridge's flexible benefit program, unless he continues to be covered through Enbridge's annuitant benefit program or the benefits program of another employer;

(c) A lump sum payment equal to the value of his annual incentive bonus to be paid for the calendar year in which termination occurs, pro rated based upon the number of days of his employment in such year;

(d) A lump sum payment equal to the value of all of his accrued and unpaid annual vacation pay to the date of his termination;

(e) A lump sum payment equal to two times the cash value of the last annual flexible perquisite allowance provided to him under Enbridge's flexible perquisites program, less any amounts paid to him but unearned by virtue of such termination of employment; and

(f) Payment for financial counseling or career counseling assistance in an amount up to a maximum of $10,000.

The agreements also provide that each of Mr. Letwin and Mr. Bird are entitled to certain benefits, including two years of additional service added to the service already accrued at the date of his termination under the Enbridge defined benefit pension plan and supplemental benefit pension plan and cash payment of certain non-vested options, if any, that are cancelled under the Incentive Stock Option Plan (ISOP) as a consequence of termination of his employment. In the case of options granted pursuant to the ISOP, the payment is calculated based on the in-the-money value of the applicable executive's non-vested option at the date of his termination.

According to the agreements, a "change of control" means:

- the sale to a person or acquisition by a person not affiliated with Enbridge or its subsidiaries of net assets of Enbridge or its subsidiaries having a value greater than 50% of the fair market value of the net assets of Enbridge and its subsidiaries determined on a consolidated basis prior to such sale whether such sale or acquisition occurs by way of reconstruction, reorganization, recapitalization, consolidation, amalgamation, arrangement, merger, transfer, sale or otherwise;

- any change in the holding, direct or indirect, of shares of Enbridge by a person not affiliated with Enbridge as a result of which such person, or a group of persons, or persons acting in concert, or persons associated or affiliated with any such person or group within the meaning of the Securities Act (Alberta), are in a position to exercise effective control of Enbridge whether such change in the holding of such shares occurs by way of takeover bid, reconstruction, reorganization, recapitalization, consolidation, amalgamation, arrangement, merger, transfer, sale or otherwise; and for the purposes of this Agreement, a person or group of persons holding shares or other securities in excess of the number which, directly or following conversion thereof, would entitle the holders thereof to cast 20% or more of the votes attaching to all shares of Enbridge which, directly or following conversion of the convertible securities forming part of the holdings of the person or group of persons noted above, may be cast to elect directors of Enbridge shall be deemed, other than a person holding such shares or other securities in the ordinary course of business as an investment manager who is not using such holding to exercise effective control, to be in a position to exercise effective control of Enbridge;

- any reconstruction, reorganization, recapitalization, consolidation, amalgamation, arrangement, merger, transfer, sale or other transaction involving Enbridge where shareholders of Enbridge immediately prior to such reconstruction, reorganization, recapitalization, consolidation, amalgamation, arrangement, merger, transfer, sale or other transaction hold less than 60% of the shares of Enbridge or of the continuing corporation following completion of such reconstruction, reorganization, recapitalization, consolidation, amalgamation, arrangement, transfer, sale or other transaction;

- Enbridge ceases to be a distributing corporation as that term is defined in the Canada Business Corporations Act;

- any event or transaction which Enbridge board of directors, in its discretion, deems to be a change of control; or
- Enbridge board of directors is no longer comprised of a majority of incumbent directors, who are defined as directors who were directors immediately prior to the occurrence of the transaction, elections or appointments giving rise to a change of control and any successor to an incumbent director who was recommended for election at a meeting of Enbridge shareholders, or elected or appointed to succeed any incumbent director, by the affirmative vote of the directors, which affirmative vote includes a majority of the incumbent directors then on the board of directors.

Each of Mr. Letwin and Mr. Bird is subject during his employment (and for two years thereafter with regard to disclosure of confidential information) to restrictions on (i) any practice or business in competition with Enbridge or its affiliates and (ii) disclosure of the confidential information of Enbridge or its affiliates.

In the event of involuntary termination without cause or because of disability or voluntary termination within 60 days of the first anniversary of the occurrence of a change of control of Enbridge or within 60 days following constructive dismissal, Enbridge would owe approximately $5 million and $6 million to Mr. Letwin and Mr. Bird, respectively. Such amounts assume that termination was effective as of December 31, 2007, and as a result include amounts earned through such time and are estimates of the amounts which would be paid out to each of Mr. Letwin and Mr. Bird upon termination under such circumstances. The actual amounts to be paid out can only be determined at the time of such executive's separation from Enbridge.

Director Compensation

As a partnership, we are managed by Enbridge Management, as the delegate of Enbridge Energy Company, Inc., our general partner. The boards of directors of Enbridge Management and our general partner, which are comprised of the same persons, perform for us the functions of a board of directors of a business corporation. We are allocated 100 percent of the director compensation of these board members. Enbridge employees who are members of the boards of directors of the General Partner or Enbridge Management do not receive any additional compensation for serving in those capacities.

As of January 1, 2006, the Director Compensation Plan was amended to increase the annual retainer to $75,000 and additional meeting fees were eliminated. The retainers paid to directors serving as the chairman of the boards and chairman of the audit committees will remain at current levels. The out of state travel fee will be increased to $1,500 per meeting. As part of this change to the Director Compensation Plan, the directors voted to amend the Corporate Governance Guidelines to incorporate an expectation that independent directors will hold a personal investment in either or both of us or Enbridge Management, of at least two times the annual board retainer, which currently would be $150,000 (i.e., 2 X $75,000 = $150,000). Directors would be expected to achieve the foregoing level of equity ownership by the later of January 1, 2011 or five years from the date they became a director.

DIRECTOR COMPENSATION

Name	Fees Earned or Paid in Cash ($)	Stock Awards ($)	Option Awards ($)	Non-Equity Incentive Plan Compensation ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)	All Other Compensation ($)	Total ($)
J.A. Connelly *Audit Committee Chairman*	84,000	—	—	—	—	—	84,000
M.O. Hesse *Chairman of the Board*	86,000	—	—	—	—	—	86,000
G.K. Petty	81,000	—	—	—	—	—	81,000
D.A. Westbrook	20,250	—	—	—	—	—	20,250

The General Partner indemnifies each director for actions associated with being a director to the full extent permitted under Delaware law and maintains errors and omissions insurance.

COMPENSATION REPORT OF THE BOARD OF DIRECTORS

The Board of Directors of Enbridge Energy Management, L.L.C., as delegate of the general partner of Enbridge Energy Partners, L.P., has reviewed and discussed the Compensation Discussion and Analysis section of this report with management and, based on that review and discussion, has recommended that the Compensation Discussion and Analysis be included in this report.

/s/ STEPHEN J.J. LETWIN	/s/ T.L. MCGILL
Stephen J.J. Letwin *Managing Director and Director*	T.L. McGill *President and Director*
/s/ J.A. CONNELLY	/s/ M.O. HESSE
J.A. Connelly *Director*	M.O. Hesse *Director*
/s/ G.K. PETTY	/s/ D.A. WESTBROOK
G.K. Petty *Director*	D.A. Westbrook *Director*

Item 12. Security Ownership of Certain Beneficial Owners and Management

SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS

The following table sets forth information as of February 20, 2008, with respect to persons known to us to be the beneficial owners of more than 5% of any class of the Partnership's units:

Name and Address of Beneficial Owner	Title of Class	Amount and Nature of Beneficial Ownership	Percent Of Class
Enbridge Energy Management, L.L.C. 1100 Louisiana, Suite 3300 Houston, TX 77002	i-units	13,815,388	100.0
Enbridge Energy Company, Inc. 1100 Louisiana, Suite 3300 Houston, TX 77002	Class B common units Class C units	3,912,750 6,032,016	100.0 32.8
CDP Infrastructures Fund G.P. 1000 place Jean-Paul-Riopelle Montreal, Québec H2Z 2B3	Class C units	11,072,473	60.1
Tortoise Energy Infrastructure Corporation 10801 Mastin Blvd., Suite 222 Overland Park, KS 66210	Class C units	1,008,091	5.5

SECURITY OWNERSHIP OF MANAGEMENT AND DIRECTORS

The following table sets forth information as of February 20, 2008, with respect to each class of our units and the Listed Shares of Enbridge Management beneficially owned by the NEOs, directors and nominees for director of the General Partner and all executive officers, directors and nominees for director of the Partnership as a group:

	Enbridge Energy Partners, L.P.			Enbridge Energy Management, L.L.C.		
Name	Title of Class	Amount and Nature of Beneficial Ownership[1]	Percent Of Class	Title of Class	Number of Shares[1]	Percent Of Class
M.O. Hesse	Class A common units	—	—	Listed Shares	8,222.05	*
J.A. Connelly	Class A common units	7,000	*	Listed Shares	—	—
G.K. Petty	Class A common units	2,617	*	Listed Shares	1,036.14	*
D.A. Westbrook	Class A common units	5,500	*	Listed Shares	—	—
S.J.J. Letwin	Class A common units	15,000	*	Listed Shares	—	—
T.L. McGill	Class A common units	—	—	Listed Shares	1,461.28	*
S.J. Wuori	Class A common units	—	—	Listed Shares	—	*
R.L. Adams	Class A common units	—	—	Listed Shares	—	—
E.C. Kaitson	Class A common units	—	—	Listed Shares	—	—
D.V. Krenz	Class A common units	—	—	Listed Shares	—	—
J.A. Loiacono	Class A common units	—	—	Listed Shares	—	—
M.A. Maki	Class A common units	—	—	Listed Shares	—	—
A. Monaco	Class A common units	—	—	Listed Shares	—	—
S.J. Neyland	Class A common units	—	—	Listed Shares	—	—
K.C. Puckett	Class A common units	—	—	Listed Shares	—	—
J.N. Rose	Class A common units	—	—	Listed Shares	—	—
A.M. Schneider	Class A common units	—	—	Listed Shares	—	—
B.A. Stevenson	Class A common units	—	—	Listed Shares	—	—
L.A. Zupan	Class A common units	—	—	Listed Shares	—	—
All Officers, directors and nominees as a group 19 persons)	Class A common units	30,117	*	Listed Shares	10,719.47	*

* Less than 1%.

(1) Each beneficial owner has sole voting and investment power with respect to all the units or shares attributed to him/her.

Item 13. Certain Relationships and Related Transactions, and Director Independence

INTEREST OF THE GENERAL PARTNER IN THE PARTNERSHIP

At December 31, 2007, our general partner had the following ownership interest in us:

	Quantity	Effective Ownership %
Direct ownership		
Class B common units representing limited partner interest	3,912,750	4.2%
Class C units representing limited partner interest	5,920,109	6.4%
General Partner interest	—	2.0%
Indirect ownership		
Enbridge Management shares (Listed and Voting)	2,336,038	2.5%
Total effective ownership	12,168,897	15.1%

INTEREST OF ENBRIDGE MANAGEMENT IN THE PARTNERSHIP

At December 31, 2007, Enbridge Management owned 13,564,086 i-units, representing a 14.7% limited partner interest in us. The i-units are a separate class of our limited partner interests. All of our i-units are owned by Enbridge Management and are not publicly traded. Enbridge Management's limited liability company agreement provides that the number of all of its outstanding shares, including the voting shares owned by the General Partner, at all times will equal the number of i-units that it owns. Through the combined effect of the provisions in the Partnership Agreement and the provisions of Enbridge Management's limited liability company agreement, the number of outstanding Enbridge Management shares and the number of our i-units will at all times be equal.

CASH DISTRIBUTIONS

As discussed in "Part II, Item 7", we make quarterly cash distributions of all of our available cash to our General Partner and the holders of our common units. The holders of our i-units and Class C units receive in-kind distributions under the Partnership Agreement. Our General Partner receives incremental incentive cash distributions on the portion of cash distributions that exceed certain target thresholds on a per unit basis as follows:

	Unitholders	General Partner
Quarterly Cash Distributions per Unit:		
Up to $0.59 per unit	98%	2%
First Target—$0.59 per unit up to $0.70 per unit	85%	15%
Second Target—$0.70 per unit up to $0.99 per unit	75%	25%
Over Second Target—Cash distributions greater than $0.99 per unit	50%	50%

During 2007, we paid cash and incentive distributions to our general partner for its general partner ownership interest of approximately $34.9 million and cash distributions of $14.5 million in connection with its ownership of the Class B common units. The cash distributions we make to our general partner for its general partner ownership interest exclude an amount equal to two percent of the i-unit and Class C unit distributions to maintain its two percent general partner interest.

IN-KIND DISTRIBUTIONS

Enbridge Management, as owner of our i-units, does not receive distributions in cash. Instead, each time that we make a cash distribution to the General Partner and the holders of our Class A and Class B common units, we issue additional i-units to Enbridge Management in an amount determined by dividing the cash amount distributed per limited partner unit by the average price of one of Enbridge Management's listed shares on the NYSE for the 10-trading day period immediately preceding the ex-dividend date for Enbridge Management's shares multiplied by the number of shares outstanding on the record date. In 2007, we distributed a total of 889,938 i-units to Enbridge Management and retained cash totaling approximately $48.4 million in connection with these in-kind distributions.

Holders of our Class C units receive quarterly distributions of additional Class C units with a value equal to the quarterly cash distribution we pay to the holders of our Class A and Class B common units. We determine the additional Class C units we will issue by dividing the quarterly cash distribution per unit we pay on our Class A and Class B common units by the average market price of a Class A common unit as listed on the NYSE for the 10-trading day period immediately preceding the ex-dividend date for our Class A common units multiplied by the number of Class C units outstanding on the record date. In 2007, we distributed a total of 385,032 Class C units to our general partner in lieu of making cash distributions and retained cash totaling approximately $21.1 million in connection with these in-kind distributions.

GENERAL PARTNER CONTRIBUTIONS

Pursuant to our partnership agreement, our general partner is at all times required to maintain its two percent general partner ownership interest in us. During 2007, in connection with our issuances and sales in April 2007 of approximately 5.9 million Class C units, and in May 2007 of 5.3 million Class A common units, our general partner contributed approximately $6.4 million and $6.1 million to us, respectively, to maintain its two percent general partner ownership interest.

OTHER RELATED PARTY TRANSACTIONS

We do not directly employ any of the individuals responsible for managing or operating our business, nor do we have any directors. We obtain managerial, administrative and operational services from our general partner and affiliates of Enbridge pursuant to service agreements among us, Enbridge Management, and affiliates of Enbridge. Pursuant to these service agreements, we have agreed to reimburse our general partner and affiliates of Enbridge for the cost of managerial, administrative, operational and director services they provide to us.

Hungary Note Payable

In December 2007, we repaid $145.0 million of a note payable to Enbridge Hungary Liquidity Management Ltd. (the "Hungary Note"), a wholly-owned subsidiary of Enbridge, including $8.8 million of accrued interest. We repaid the Hungary Note with proceeds we received from entering into a new note payable agreement with Hungary Liquidity Management Ltd. (the "new Hungary Note") on substantially the same terms, and approximately $15 million from our existing cash. The new Hungary Note bears interest at a fixed rate of 8.4% per annum that is payable semi-annually in June and December of each year through its maturity in December 2017. Similar to the old Hungary Note, the new note allows us the option of paying accrued and unpaid interest in the form of additional indebtedness by increasing the principal balance of the note for the amounts due. Consistent with the original Hungary Note, the new Hungary Note has cross-default provisions that are triggered by events of default under our First Mortgage Notes or defaults under our Credit Facility. The new Hungary Note is subordinate to our Credit Facility and other senior indebtedness, and ranks equally with current and future Junior Notes. We entered into the original Hungary Note agreement in connection with our acquisition of the Midcoast system in October 2002.

EUS Credit Agreement

In December 2007, we entered into an unsecured revolving credit agreement (the "EUS Credit Agreement") with Enbridge (U.S.) Inc., a wholly-owned subsidiary of Enbridge. The EUS Credit Agreement provides for a maximum principal amount of credit available to us at any one time of $500 million for a three-year term that matures in December 2010. The EUS Credit Agreement also includes financial covenants that are consistent with those in our Second Amended and Restated Credit Agreement. Amounts borrowed under the EUS Credit Agreement bear interest at rates that are consistent with the interest rates set forth in our Second Amended and Restated Credit Agreement. At December 31, 2007, we had no balances outstanding under the EUS Credit Agreement and the full amount remains available for our use.

Facilities Cost Reimbursement Agreement

In 2007, we entered into an agreement with Enbridge Pipelines Inc., a wholly-owned subsidiary of Enbridge, to install and operate certain sampling and related facilities for the purpose of improving the quality of crude oil and the transportation services on our Lakehead system, which directly increases the transportation services revenue of Enbridge Pipelines Inc. As compensation for installing and operating these transportation facilities, Enbridge Pipelines Inc. makes annual payments to us on a cost of service basis. The income we accrued for providing these transportation services in 2007 was approximately $0.6 million.

For further discussion of these and other related party transactions, refer to "Note 11—Related Party Transactions" in the consolidated financial statements beginning on Page F-2 of this Annual Report on Form 10-K.

REVIEW, APPROVAL OR RATIFICATION OF TRANSACTIONS WITH RELATED PERSONS

If we contemplate entering into a transaction, other than a routine or in the ordinary course of business transaction, in which a related person will have a direct or indirect material interest, the proposed transaction is submitted for consideration to the board of directors of our general partner or Enbridge Management, as appropriate. The board of directors then determines whether it is advisable to constitute a special committee of independent directors to evaluate the proposed transaction. If a special committee is appointed, the committee obtains information regarding the proposed transaction from management and determines whether it is advisable to engage independent legal counsel or an independent financial advisor to advise the members of the committee regarding the transaction. If the special committee retains such counsel or financial advisor, it considers the advice and, in the case of a financial advisor, such advisor's opinion as to whether the transaction is fair to us and all of our unitholders.

Potential transactions with related persons that are not financially significant so as to require review by the board of directors are disclosed to the President of Enbridge Management and our general partner and reviewed for compliance with the Enbridge Statement on Business Conduct. The President may also consult with legal counsel in making such determination. If a related person transaction occurred and was later found not to comply with the Statement on Business Conduct, the transaction would be reported to the board of directors for further review and ratification or remedial action.

During 2007, we had the following "related person" transactions (as the term is defined in Item 404 of Regulation S-K):

- An affiliate of Enbridge which provides employee services to the Partnership continued a previously existing employment relationship with Jan Connelly, the sister of Jeffrey A. Connelly, a member of the Board of Directors. Ms. Connelly is employed in our Michigan office as the Manager, Origination. During 2007, she received total cash compensation of $162,737.97 and benefits estimated at approximately 35% of her cash compensation for a total of $219,696.26.

Item 14. Principal Accountant Fees and Services

The following table sets forth the aggregate fees billed for professional services rendered by PricewaterhouseCoopers LLP, our principal independent auditors, for each of our last two fiscal years.

	For the years ended December 31, 2007	2006
Audit fees[1]	$ 2,453,000	$ 2,405,200
Audit related fees	—	—
Tax fees[2]	702,500	625,000
All other fees	—	—
Total	$ 3,155,500	$ 3,030,200

(1) Audit fees consist of fees billed for professional services rendered for the audit of our consolidated financial statements, reviews of our interim consolidated financial statements, audits of various subsidiaries for statutory and regulatory filing requirements and our debt and equity offerings.

(2) Tax fees consist of fees billed for professional services rendered for federal and state tax compliance for Partnership tax filings and unitholder K-1's.

Engagements for services provided by PricewaterhouseCoopers LLP are subject to pre-approval by the Audit, Finance & Risk Committee of Enbridge Management's board of directors, or services up to $50,000 may be approved by the Chairman of the Audit, Finance & Risk Committee, under board of directors' delegated authority. All services in 2007 and 2006 were approved by the Audit, Finance & Risk Committee.

PART IV

Item 15. Exhibits, Financial Statement Schedules

The following documents are filed as a part of this report:

(1) *Financial Statements, which are incorporated by reference in Item 8 are included beginning on page F-1.*

a. Report of PricewaterhouseCoopers LLP, Independent Registered Public Accounting Firm.

b. Consolidated Statements of Income for the years ended December 31, 2007, 2006, and 2005.

c. Consolidated Statements of Comprehensive Income for the years ended December 31, 2007, 2006, and 2005.

d. Consolidated Statements of Cash Flows for the years ended December 31, 2007, 2006, and 2005.

e. Consolidated Statements of Financial Position as of December 31, 2007 and 2006.

f. Consolidated Statements of Partners' Capital for the years ended December 31, 2007, 2006, and 2005.

g. Notes to the Consolidated Financial Statements.

(2) *Financial Statement Schedules.*

All schedules have been omitted because they are not applicable, the required information is shown in the consolidated financial statements or Notes thereto, or the required information is immaterial.

(3) *Exhibits.*

Reference is made to the "Index of Exhibits" following the signature page, which is hereby incorporated into this Item.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized.

ENBRIDGE ENERGY PARTNERS, L.P.
(Registrant)

By: Enbridge Energy Management, L.L.C.,
as delegate of the General Partner

By: /s/ STEPHEN J.J. LETWIN

Stephen J.J. Letwin
(Managing Director)

Date: February 21, 2008

Pursuant to the requirements of the Securities Exchange Act of 1934, this Report has been signed below on February 21, 2008 by the following persons on behalf of the Registrant and in the capacities indicated.

/s/ STEPHEN J.J. LETWIN	/s/ M.A. MAKI
Stephen J.J. Letwin *Managing Director* *(Principal Executive Officer)*	M.A. Maki *Vice President—Finance* *(Principal Financial Officer)*
/s/ T.L. MCGILL	/s/ S.J. NEYLAND
T.L. McGill *President and Director*	S.J. Neyland *Controller*
/s/ J.A. CONNELLY	/s/ M.O. HESSE
J.A. Connelly *Director*	M.O. Hesse *Director*
/s/ G.K. PETTY	/s/ D.A. WESTBROOK
G.K. Petty *Director*	D.A. Westbrook *Director*

Index of Exhibits

Each exhibit identified below is filed as a part of this Annual report. Exhibits included in this filing are designated by an asterisk; all exhibits not so designated are incorporated by reference to a prior filing as indicated. Exhibits designated with a "+" constitute a management contract or compensatory plan arrangement required to be filed as an exhibit to this report pursuant to Item 15(c) of Form 10-K.

Exhibit Number	Description
3.1	Certificate of Limited Partnership of the Partnership (incorporated by reference to Exhibit 3.1 of the Partnership's Registration Statement No. 33-43425).
3.2	Certificate of Amendment to Certificate of Limited Partnership of the Partnership (incorporated by reference to Exhibit 3.2 of the Partnership's 2000 Form 10-K/A dated October 9, 2001).
3.3	Fourth Amended and Restated Agreement of Limited Partnership of the Partnership, dated August 15, 2006 (incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K dated August 16, 2006).
3.4	First Amendment to the Fourth Amended and Restated Agreement of Limited Partnership of the Partnership, dated December 28, 2007 (incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K dated January 3, 2008).
4.1	Form of Certificate representing Class A Common Units (incorporated by reference to Exhibit 4.1 of the Partnership's 2000 Form 10-K/A dated October 9, 2001).
4.2	Registration Rights Agreement, dated August 15, 2006, between Enbridge Energy Partners, L.P. and CDP Infrastructures Fund G.P. (incorporated by reference to Exhibit 4.1 of our Current Report on Form 8-K dated August 16, 2006).
4.3	Registration Rights Agreement, dated April 2, 2007, between Enbridge Energy Partners, L.P. and CDP Infrastructures Fund G.P., Tortoise Energy Infrastructure Corporation and Tortoise Energy Capital Corporation (incorporated by reference to Exhibit 4.1 of our Current Report on Form 8-K dated April 2, 2007).
10.1	Contribution, Conveyance and Assumption Agreement, dated December 27, 1991, among Lakehead Pipe Line Company, Inc., Lakehead Pipe Line Partners, L.P. and Lakehead Pipe Line Company, Limited Partnership. (incorporated by reference to Exhibit 10.10 of the Partnership's 1991 Form 10-K).
10.2	LPL Contribution and Assumption Agreement, dated December 27, 1991, among Lakehead Pipe Line Company, Inc., Lakehead Pipe Line Partners, L.P. and Lakehead Pipe Line Company, Limited Partnership and Lakehead Services, Limited Partnership. (incorporated by reference to Exhibit 10.11 of the Partnership's 1991 Form 10-K).
10.3	Contribution Agreement (incorporated by reference to Exhibit 10.1 of the Partnership's Registration Statement on Form S-3/A filed on July 8, 2002).
10.4	First Amendment to Contribution Agreement (incorporated by reference to Exhibit 10.8 of the Partnership's Registration Statement on Form S-3/A filed on September 24, 2002).
10.5	Second Amendment to Contribution Agreement (incorporated by reference to Exhibit 99.3 of the Partnership's Current Report on Form 8-K filed on October 31, 2002).
10.6	Delegation of Control Agreement (incorporated by reference to Exhibit 10.2 of the Partnership's Quarterly Report on Form 10-Q filed on November 14, 2002).
10.7	First Amending Agreement to the Delegation of Control Agreement dated as of February 21, 2005 (incorporated by reference to Exhibit 10.1 of the Partnership's Quarterly Report on Form 10-Q filed on May 5, 2005).
10.8	Amended and Restated Treasury Services Agreement (incorporated by reference to Exhibit 10.3 of the Partnership's Quarterly Report on Form 10-Q filed on November 14, 2002).

10.9	Operational Services Agreement (incorporated by reference to Exhibit 10.4 of the Partnership's Quarterly Report on Form 10-Q filed on November 14, 2002).
10.10	General and Administrative Services Agreement (incorporated by reference to Exhibit 10.5 of the Partnership's Quarterly Report on Form 10-Q filed on November 14, 2002).
10.11	Omnibus Agreement (incorporated by reference to Exhibit 10.6 of the Partnership's Quarterly Report on Form 10-Q filed on November 14, 2002).
10.12	Second Amended and Restated Credit Agreement, dated April 4, 2007, among Enbridge Energy Partners, L.P., Bank of America, N.A., as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K dated April 10, 2007).
10.13	Commercial Paper Dealer Agreement between the Company, as Issuer, and Banc of America Securities LLC, as Dealer, dated as of April 21, 2005 (incorporated by reference to Exhibit 10.1 of the Partnership's Current Report on Form 8-K filed May 3, 2005).
10.14	Commercial Paper Dealer Agreement between the Company, as Issuer, and Deutsche Bank Securities Inc., as Dealer, dated as of April 21, 2005 (incorporated by reference to Exhibit 10.2 of the Partnership's Current Report on Form 8-K filed May 3, 2005).
10.15	Commercial Paper Dealer Agreement between the Company, as Issuer, and Goldman, Sachs & Co., as Dealer, dated as of April 21, 2005 (incorporated by reference to Exhibit 10.3 of the Partnership's Current Report on Form 8-K filed May 3, 2005).
10.16	Commercial Paper Dealer Agreement between the Company, as Issuer, and Merrill Lynch Money Markets Inc., as Dealer, dated as of April 21, 2005 (incorporated by reference to Exhibit 10.4 of the Partnership's Current Report on Form 8-K filed May 3, 2005).
10.17	Issuing and Paying Agency Agreement between the Company and Deutsche Bank Trust Company Americas, dated as of April 21, 2005 (incorporated by reference to Exhibit 10.5 of the Partnership's Current Report on Form 8-K filed May 3, 2005).
10.18	Note Agreement and Mortgage, dated December 12, 1991 (incorporated by reference to Exhibit 10.1 of the Partnership's 1991 Form 10-K).
10.19	Assumption and Indemnity Agreement, dated December 18, 1992, between Interprovincial Pipe Line Inc. and Interprovincial Pipe Line System Inc. (incorporated by reference to Exhibit 10.4 of the Partnership's 1992 Form 10-K).
10.20	Settlement Agreement, dated August 28, 1996, between Lakehead Pipe Line Company, Limited Partnership and the Canadian Association of Petroleum Producers and the Alberta Department of Energy (incorporated by reference to Exhibit 10.17 of the Partnership's 1996 Form 10-K).
10.21	Tariff Agreement as filed with the Federal Energy Regulatory Commission for the System Expansion Program II and Terrace Expansion Project (incorporated by reference to Exhibit 10.21 of the Partnership's 1998 Form 10-K).
10.22	Offer of Settlement dated December 31, 2005, as filed with the Federal Energy Regulatory Commission for approval to implement an additional component of the Facilities Surcharge to permit recovery by Enbridge Energy, Limited Partnership of the costs for the Southern Access Mainline Expansion and approval of the Offer of Settlement dated March 16, 2006 (incorporated by reference to Exhibit 10.3 of the Partnership's Quarterly Report on Form 10-Q filed July 30, 2007).
10.23	Promissory Note, dated as of September 30, 1998, given by Lakehead Pipe Line Company, Limited Partnership, as borrower, to Lakehead Pipe Line Company, Inc., as lender (incorporated by reference to Exhibit 10.19 of the Partnership's 1998 Form 10-K).
10.24	Promissory Note, dated as of March 31, 1999, given by Lakehead Pipe Line Company, Limited Partnership, as borrower, to Lakehead Pipe Line Company, Inc., as lender. (incorporated by reference to Exhibit 10.26 of the Partnership's 1999 Form 10-K).

10.25	Indenture dated September 15, 1998, between Lakehead Pipe Line Company, Limited Partnership and the Chase Manhattan Bank (incorporated by reference to Exhibit 4.1 of the Lakehead Pipe Line Company, Limited Partnership's Current Report on Form 8-K dated October 20, 1998).
10.26	First Supplemental Indenture dated September 15, 1998, between Lakehead Pipe Line Company, Limited Partnership and the Chase Manhattan Bank (incorporated by reference to Exhibit 4.2 of the Lakehead Pipe Line Company, Limited Partnership's Current Report on Form 8-K dated October 20, 1998).
10.27	Second Supplemental Indenture dated September 15, 1998, between Lakehead Pipe Line Company, Limited Partnership and the Chase Manhattan Bank (incorporated by reference to Exhibit 4.3 of the Lakehead Pipe Line Company, Limited Partnership's Current Report on Form 8-K dated October 20, 1998).
10.28	Third Supplemental Indenture dated November 21, 2000, between Lakehead Pipe Line Company, Limited Partnership and the Chase Manhattan Bank (incorporated by reference to Exhibit 4.2 of the Lakehead Pipe Line Company, Limited Partnership's Current Report on Form 8-K dated November 16, 2000).
10.29	Indenture dated September 15, 1998, between Lakehead Pipe Line Company, Limited Partnership and the Chase Manhattan Bank (incorporated by reference to Exhibit 4.4 of the Lakehead Pipe Line Company, Limited Partnership's Current Report on Form 8-K dated October 20, 1998).
10.30+	Executive Employment Agreement, dated April 14, 2003, between Stephen J.J. Letwin, as Executive, and Enbridge Inc., as Corporation (incorporated by reference to Exhibit 10.1 of the Partnership's Current Report on Form 8-K filed on May 3, 2006).
10.31+	Executive Employment agreement between Stephen J. Wuori and Enbridge Inc. dated April 14, 2003 (incorporated by reference to our Current Report on Form 8-K dated January 28, 2008).
10.32+	Executive Employment Agreement, dated May 11, 2001, between E. Chris Kaitson, as Executive, and Enbridge Inc., as Corporation (incorporated by reference to Exhibit 10.27 of the Partnership's Annual Report on Form 10-K filed on March 28, 2003).
10.33	Indenture dated May 27, 2003, between the Partnership, as Issuer, and SunTrust Bank, as Trustee (incorporated by reference to Exhibit 4.5 of the Partnership's Registration Statement on Form S-4 filed on June 30, 2003).
10.34	First Supplemental Indenture dated May 27, 2003 between the Partnership and SunTrust Bank (incorporated by reference to Exhibit 4.5 of the Partnership's Registration Statement on Form S-4 filed on June 30, 2003).
10.35	Second Supplemental Indenture dated May 27, 2003 between the Partnership and SunTrust Bank (incorporated by reference to Exhibit 4.5 of the Partnership's Registration Statement on Form S-4 filed on June 30, 2003).
10.36	Third Supplemental Indenture dated January 9, 2004 between the Partnership and SunTrust Bank (incorporated by reference to Exhibit 99.3 of the Partnership's Current Report on Form 8-K filed on January 9, 2004).
10.37	Fourth Supplemental Indenture dated December 3, 2004 between the Partnership and SunTrust Bank (incorporated by reference to Exhibit 4.2 of the Partnership's Current Report on Form 8-K filed on December 3, 2004).
10.38	Fifth Supplemental Indenture dated December 3, 2004 between the Partnership and SunTrust Bank (incorporated by reference to Exhibit 4.3 of the Partnership's Current Report on Form 8-K filed on December 3, 2004).

10.39	Sixth Supplemental Indenture dated December 21, 2006 between the Partnership and U.S. Bank National Association, successor to SunTrust Bank, as trustee (incorporated by reference to Exhibit 4.2 of the Partnership's Current Report on Form 8-K filed on December 21, 2006).
10.40	Indenture for Subordinated Debt Securities dated as of September 27, 2007 between Enbridge Energy Partners, L.P. and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.1 of the Partnership's Current Report on Form 8-K dated September 28, 2007).
10.41	First Supplemental Indenture to the Indenture dated as of September 27, 2007 between Enbridge Energy Partners, L.P. and U.S. Bank National Association, as Trustee (including form of Note) (incorporated by reference to Exhibit 4.2 of the Partnership's Current Report on Form 8-K dated September 28, 2007).
10.42	Replacement Capital Covenant dated as of September 27, 2007 by Enbridge Energy Partners, L.P. in favor of the debtholders designated therein (incorporated by reference to Exhibit 10.1 of the Partnership's Current Report on Form 8-K dated September 28, 2007).
10.43	Common Unit Purchase Agreement (incorporated by reference to Exhibit 1.1 of the Partnership's Current Report on Form 8-K filed on February 10, 2005).
14.1	Code of Ethics for Senior Financial Officers (incorporated by reference to Exhibit 14.1 of the Partnership's Annual Report on Form 10-K filed on March 12, 2004).
21.1*	Subsidiaries of the Registrant.
23.1*	Consent of PricewaterhouseCoopers LLP.
31.1*	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certification of Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2*	Certification of Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1	Charter of the Audit, Finance & Risk Committee of Enbridge Energy Management, L.L.C. (incorporated by reference to Exhibit 99.1 of the Partnership's Annual Report on Form 10-K filed February 25, 2005).

Copies of Exhibits may be obtained upon written request of any Unitholder to Investor Relations, Enbridge Energy Partners, L.P., 1100 Louisiana, Suite 3300, Houston, Texas 77002.

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS, SUPPLEMENTARY INFORMATION AND CONSOLIDATED FINANCIAL STATEMENT SCHEDULES

ENBRIDGE ENERGY PARTNERS, L.P.

FINANCIAL STATEMENT SCHEDULES

Financial statement schedules not included in this report have been omitted because they are not applicable or the required information is either immaterial or shown in the consolidated financial statements or notes thereto.

Report of Independent Registered Public Accounting Firm

To the Partners of
Enbridge Energy Partners, L.P.:

In our opinion, the accompanying consolidated statements of financial position and the related consolidated statements of income and comprehensive income, of partners capital and of cash flows present fairly, in all material respects, the financial position of Enbridge Energy Partners, L.P. and its subsidiaries (the "Partnership") at December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Partnership's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements and on the Partnership's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PricewaterhouseCoopers LLP

Houston, Texas
February 21, 2008

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF INCOME

	Year ended December 31,		
	2007	2006	2005
	(in millions, except per unit amounts)		
Operating revenue	$ 7,282.6	$ 6,509.0	$ 6,476.9
Operating expenses			
Cost of natural gas (Note 5 and 14)	6,246.9	5,514.6	5,763.3
Operating and administrative	434.3	364.8	326.8
Power	117.0	107.6	74.8
Depreciation and amortization (Note 6)	165.6	135.1	138.2
Gain on sale of assets (Note 3)	—	—	(18.1)
	6,963.8	6,122.1	6,285.0
Operating income	318.8	386.9	191.9
Interest expense	99.8	110.5	107.7
Other income	3.0	8.5	5.0
Income from continuing operations before income tax expense	222.0	284.9	89.2
Income tax expense (Note 15)	5.1	—	—
Income from continuing operations	216.9	284.9	89.2
Income from discontinued operations (Note 3)	32.6	—	—
Net income	$ 249.5	$ 284.9	$ 89.2
Net income allocable to limited partner units (Note 4)			
Income from continuing operations	$ 179.9	$ 254.0	$ 65.7
Income from discontinued operations	31.9	—	—
Net income allocable to limited partner units	$ 211.8	$ 254.0	$ 65.7
Basic and diluted earnings per limited partner unit (Note 4)			
Income from continuing operations	$ 2.08	$ 3.62	$ 1.06
Income from discontinued operations	0.37	—	—
Net income per limited partner unit (basic and diluted)	$ 2.45	$ 3.62	$ 1.06
Weighted average limited partner units outstanding	86.3	70.2	62.1
Cash distributions paid per limited partner unit	$ 3.725	$ 3.700	$ 3.700

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year ended December 31,		
	2007	**2006**	**2005**
		(in millions)	
Net income	$ 249.5	$ 284.9	$ 89.2
Other comprehensive income (loss) net of tax benefit of $1.6, $0.9, and $0, respectively (Note 14)	(104.8)	112.5	(181.3)
Comprehensive income (loss)	$ 144.7	$ 397.4	$ (92.1)

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year ended December 31,		
	2007	2006	2005
		(in millions)	
Cash provided by operating activities			
Net income	$ 249.5	$ 284.9	$ 89.2
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization (Note 6)	165.6	135.1	138.2
Derivative fair value losses (gains) (Notes 13 and 14)	64.2	(64.4)	58.4
Gain on sale of net assets (Note 3)	(32.6)	—	(18.1)
Inventory market price adjustments (Note 5)	4.5	17.7	—
Other	1.8	8.3	(0.8)
Changes in operating assets and liabilities, net of acquisitions:			
Receivables, trade and other	(11.1)	(37.0)	(38.0)
Due from General Partner and affiliates (Note 11)	3.3	(10.4)	(12.4)
Accrued receivables	(82.3)	98.8	(237.1)
Inventory (Note 5)	2.0	1.1	(57.5)
Current and long-term other assets (Notes 13 and 14)	(3.9)	(2.7)	(2.2)
Due to General Partner and affiliates (Note 11)	23.2	10.1	2.6
Accounts payable and other (Notes 2, 13 and 14)	(3.1)	4.3	42.2
Accrued purchases	73.5	(116.4)	295.3
Interest payable	9.5	4.4	8.8
Current income tax payable (Note 15)	4.9	—	—
Property and other taxes payable	(4.7)	(2.0)	(1.5)
Settlement of interest rate derivatives (Note 14)	(0.9)	(10.2)	—
Net cash provided by operating activities	463.4	321.6	267.1
Cash used in investing activities			
Additions to property, plant and equipment	(1,980.2)	(864.4)	(344.8)
Changes in construction payables	83.6	30.4	2.8
Asset acquisitions, net of cash acquired (Note 3)	—	(33.3)	(186.4)
Proceeds from sale of net assets (Note 3)	133.0	0.2	105.4
Settlement of natural gas collars (Note 3 and 14)	—	—	(16.3)
Other	(1.4)	0.1	2.2
Net cash used in investing activities	(1,765.0)	(867.0)	(437.1)
Cash provided by financing activities			
Net Proceeds from unit issuances (Note 10)	628.8	509.6	268.6
Distributions to partners (Note 10)	(245.4)	(227.4)	(210.6)
Net proceeds from issuances of long term debt (Note 9)	592.8	297.6	—
Net Credit Facility borrowings (repayments) (Note 9)	400.0	—	(175.0)
Net commercial paper issuances (repayments) (Note 9)	(171.5)	111.4	330.0
Affiliate note borrowings (Note 11)	130.0	—	—
Affiliate note repayments (Note 11)	(136.2)	(20.0)	—
Repayments of First Mortgage Notes (Note 9)	(31.0)	(31.0)	(31.0)
Other	—	—	(0.5)
Net cash provided by financing activities	1,167.5	640.2	181.5
Net increase (decrease) in cash and cash equivalents	(134.1)	94.8	11.5
Cash and cash equivalents at beginning of year	184.6	89.8	78.3
Cash and cash equivalents at end of year	$ 50.5	$ 184.6	$ 89.8

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	December 31, 2007	December 31, 2006
	(dollars in millions)	
ASSETS		
Current assets		
Cash and cash equivalents (Note 2)	$ 50.5	$ 184.6
Receivables, trade and other, net of allowance for doubtful accounts of $1.9 in 2007 and $2.4 in 2006	157.8	146.7
Due from General Partner and affiliates (Note 11)	27.2	30.5
Accrued receivables	598.8	516.5
Inventory (Note 5)	110.6	117.1
Other current assets (Notes 13 and 14)	14.8	13.9
	959.7	1,009.3
Property, plant and equipment, net (Note 6)	5,554.9	3,824.9
Goodwill (Note 7)	256.5	265.7
Intangibles, net (Note 8)	91.5	97.8
Other assets, net (Notes 13, 14 and 15)	29.0	26.1
	$ 6,891.6	$ 5,223.8
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Due to General Partner and affiliates (Note 11)	$ 45.8	$ 22.6
Accounts payable and other (Notes 13 and 14)	400.4	211.5
Accrued purchases	603.8	530.3
Interest payable	20.9	11.4
Property and other taxes payable (Note 15)	22.5	18.6
Notes payable to affiliate (Note 11)	—	136.2
Current maturities of long-term debt (Note 9)	31.0	31.0
	1,124.4	961.6
Long-term debt (Note 9)	2,862.9	2,066.1
Environmental liabilities (Note 12)	2.8	3.3
Notes payable to affiliate (Note 11)	130.0	—
Other long-term liabilities (Notes 13 and 14)	200.0	149.4
	4,320.1	3,180.4
Commitments and contingencies (Note 12)		
Partners' capital (Note 10)		
Class A common units (55,238,834 and 49,938,834 at December 31, 2007 and 2006, respectively)	1,340.7	1,141.7
Class B common units (3,912,750 at December 31, 2007 and 2006)	72.9	67.6
Class C units (18,073,367 and 11,070,152 at December 31, 2007 and 2006, respectively)	874.1	509.8
i-units (13,564,086 and 12,674,148 at December 31, 2007 and 2006, respectively)	515.3	466.3
General Partner	62.9	47.6
Accumulated other comprehensive loss (Notes 13 and 14)	(294.4)	(189.6)
	2,571.5	2,043.4
	$ 6,891.6	$ 5,223.8

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE ENERGY PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL

	Year ended December 31,					
	2007		2006		2005	
	Units	Amount	Units	Amount	Units	Amount
			(in millions, except unit amounts)			
Class A common units:						
Beginning balance	49,938,834	$ 1,141.7	49,938,834	$ 1,142.4	44,296,134	$ 1,021.6
Net income allocation	—	130.1	—	184.1	—	48.9
Allocation of proceeds and issuance costs from unit issuance	5,300,000	264.9	—	—	5,642,700	242.7
Distributions	—	(196.0)	—	(184.8)	—	(170.8)
Ending balance	55,238,834	1,340.7	49,938,834	1,141.7	49,938,834	1,142.4
Class B common units:						
Beginning balance	3,912,750	67.6	3,912,750	67.2	3,912,750	66.7
Net income allocation	—	9.8	—	14.9	—	4.8
Allocation of proceeds and issuance costs from unit issuance	—	10.0	—	—	—	10.2
Distributions	—	(14.5)	—	(14.5)	—	(14.5)
Ending balance	3,912,750	72.9	3,912,750	67.6	3,912,750	67.2
Class C units:						
Beginning balance	11,070,152	509.8	—	—	—	—
Net income allocation	—	39.9	—	10.4	—	—
Allocation of proceeds and issuance costs from unit issuance	5,930,792	324.4	10,869,565	499.4	—	—
Distributions	1,072,423	—	200,587	—	—	—
Ending balance	18,073,367	874.1	11,070,152	509.8	—	—
i-units:						
Beginning balance	12,674,148	466.3	11,704,948	421.7	10,902,409	399.4
Net income allocation	—	32.0	—	44.6	—	12.0
Allocation of proceeds and issuance costs from unit issuance	—	17.0	—	—	—	10.3
Distributions	889,938	—	969,200	—	802,539	—
Ending balance	13,564,086	515.3	12,674,148	466.3	11,704,948	421.7
General Partner:						
Beginning balance		47.6		34.6		31.0
Net income allocation		37.7		30.9		23.5
Allocation of proceeds and issuance costs from unit issuance		—		—		(0.3)
General Partner contribution		12.5		10.2		5.7
Distributions		(34.9)		(28.1)		(25.3)
Ending balance		62.9		47.6		34.6
Accumulated other comprehensive loss:						
Beginning balance		(189.6)		(302.1)		(120.8)
Net realized losses on changes in fair value of derivative financial instruments reclassified to earnings		94.8		78.3		33.8
Unrealized gain (loss) on derivative financial instruments		(199.6)		34.2		(215.1)

Ending balance	(294.4)	(189.6)	(302.1)
Partners' capital at December 31,	$ 2,571.5	$ 2,043.4	$ 1,363.8

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE ENERGY PARTNERS, L.P.
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. PARTNERSHIP ORGANIZATION AND NATURE OF OPERATIONS

General

Enbridge Energy Partners, L.P. and its consolidated subsidiaries, referred to herein as "we," "us," "our," and the "Partnership," is a publicly-traded Delaware limited partnership that owns and operates crude oil and liquid petroleum transportation and storage assets, and natural gas gathering, treating, processing, transmission and marketing assets in the United States of America. Our Class A common units are traded on the New York Stock Exchange ("NYSE") under the symbol "EEP."

We were formed in 1991 by Enbridge Energy Company, Inc. (the "General Partner"), which is an indirect, wholly-owned subsidiary of Enbridge Inc. ("Enbridge") of Calgary, Alberta. We were formed to acquire, own and operate the crude oil and liquid petroleum transportation assets of Enbridge Energy, Limited Partnership (the "OLP") which owns the United States portion of a crude oil and liquid petroleum pipeline system extending from western Canada through the upper and lower Great Lakes region of the United States to eastern Canada.

We are a geographically and operationally diversified organization, providing crude oil gathering, transportation and storage services, and natural gas gathering, treating, processing, marketing and transportation services in the Gulf Coast and Mid-continent regions of the United States. We hold our assets in a series of limited liability companies and limited partnerships that we own directly or indirectly.

Our ownership includes general partner interests and limited partner interests. Our limited partner interests consist of Class A and Class B common units, Class C units and i-units, which we collectively refer to as the limited partner units. At December 31, 2007 and 2006, our ownership is distributed as follows:

	2007	2006
Class A common units owned by the public	59.6%	63.1%
Class B common units owned by our General Partner	4.2%	4.9%
Class C units owned by our General Partner	6.4%	7.0%
Class C units owned by institutional investors	13.1%	7.0%
i-units owned by Enbridge Management	14.7%	16.0%
General Partner interest	2.0%	2.0%
	100.0%	100.0%

Enbridge Energy Management, L.L.C.

Enbridge Energy Management, L.L.C. and its subsidiary, which we refer to as Enbridge Management, is a Delaware limited liability company that was formed in May 2002. Our general partner, through its direct ownership of the voting shares of Enbridge Management, elects all of the directors of Enbridge Management. Enbridge Management's Listed Shares are traded on the NYSE under the symbol "EEQ." Enbridge Management owns all of a special class of our limited partner interests, referred to as "i-units" and receives its earnings from this investment.

Enbridge Management's principal activity is managing and controlling our business and affairs pursuant to a delegation of control agreement with our general partner. The delegation of control agreement provides that Enbridge Management will not amend or propose to amend our partnership agreement, allow a merger or consolidation involving us, allow a sale or exchange of all or substantially all of our assets or dissolve or liquidate us without the approval of our general partner. In accordance with its limited liability company agreement, Enbridge Management's activities are restricted to being our limited partner and managing our business and affairs.

Enbridge Inc.

Enbridge is the indirect parent of our general partner and is publicly traded on the NYSE and Toronto Stock Exchange under the symbol "ENB." Enbridge is a leader in the transportation and distribution of energy, with a focus on crude oil and liquids pipelines, natural gas pipelines and natural gas distribution in North America. Enbridge also has international interests located in Western Europe and Latin America. At December 31, 2007 and 2006, Enbridge and its consolidated subsidiaries owned an effective 15.1% and 16.7% interest in us through its ownership in Enbridge Management and our general partner.

Business Segments

We conduct our business through three segments: Liquids, Natural Gas, and Marketing.

Liquids

Our Liquids segment includes the Lakehead, North Dakota, and the Mid-Continent systems. Our Lakehead system consists of an interstate common carrier crude oil and liquid petroleum pipeline that is regulated by the Federal Energy Regulatory Commission, or FERC, and storage assets, all of which are located in the Great Lakes and Midwest regions of the United States. Our Lakehead system, together with the Enbridge system in Canada owned by Enbridge, forms the longest liquid petroleum pipeline in the world. The Lakehead system, which spans approximately 3,300 miles, has been in operation for over 50 years and is the primary transporter of crude oil and liquid petroleum from western Canada to the United States. The Lakehead system serves all the major refining centers in the Great Lakes and Midwest regions of the United States and the province of Ontario, Canada. Our North Dakota system includes approximately 330 miles of crude oil gathering lines connected to an interstate transportation line that is approximately 620 miles long and is regulated by the FERC. The North Dakota system connects directly into the Lakehead system in the state of Minnesota. Our Mid-Continent system consists of over 480 miles of active crude oil pipelines, including the FERC-regulated Ozark pipeline and approximately 16.7 million barrels of storage capacity, which serve refineries in the U.S. Mid-continent region from Cushing, Oklahoma.

Natural Gas

Our Natural Gas segment consists of natural gas gathering and transmission pipelines, treating and processing plants and related facilities predominantly located in active producing basins in east and north Texas, as well as the Texas panhandle and western Oklahoma. Our Natural Gas segment includes ten natural gas treating plants and 24 natural gas processing plants at December 31, 2007, excluding plants that are inactive or under construction. In addition, our Natural Gas segment includes approximately 11,500 miles of natural gas gathering and transmission pipelines, as well as trucks, trailers and rail cars used for transporting natural gas liquids ("NGL" or "NGLs"), crude oil and carbon dioxide.

Our Natural Gas segment also includes three FERC-regulated natural gas transmission pipeline systems located in the Southeast and Gulf Coast regions of the United States.

Marketing

Our Marketing segment primarily provides natural gas supply, transportation, balancing, storage and sales services for producers and wholesale customers on our natural gas pipelines as well as other interconnected natural gas pipeline systems. We primarily undertake marketing activities to increase the utilization of our natural gas pipelines, realize incremental income on gas purchased at the wellhead, and provide value-added services to customers.

Our Marketing business purchases third-party pipeline transportation capacity which provides us and our customers with access to natural gas markets that might not be directly accessible from our existing natural gas pipelines. Our Marketing business also purchases third-party storage capacity which permits us to inject and store natural gas over various periods of time for withdrawal as these products become needed by end users of natural gas. These contracts may be denoted as firm transportation, interruptible transportation, firm storage, interruptible storage, or parking and lending services. These various contract structures are used to mitigate risk associated with our natural gas purchase and sale contracts and to provide us with opportunities to competitively market natural gas and NGL products.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation and Use of Estimates

We prepare our consolidated financial statements in accordance with accounting principles generally accepted in the United States of America ("GAAP"). Our preparation of these consolidated financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and the disclosure of contingent assets and liabilities. We regularly evaluate these estimates utilizing historical experience, consultation with experts and other methods we consider reasonable in the circumstances. Nevertheless, actual results may differ significantly from these estimates. We record the effect of any revisions to these estimates in our consolidated financial statements in the period in which the facts that give rise to the revision become known.

Principles of Consolidation

The consolidated financial statements include the accounts of the Partnership and its wholly-owned subsidiaries on a consolidated basis. All significant intercompany accounts and transactions have been eliminated in consolidation.

Comparative Amounts

We have made a reclassification to the prior years' reported amounts to conform to our presentation in the 2007 consolidated statements of financial position between other assets, net and intangibles, net. We reclassified $6.4 million from other assets, net to intangibles, net in our December 31, 2006 consolidated statement of financial position related to rights we received for contributions we made in aid of construction projects, consistent with our current period presentation.

Accounting for Regulated Operations

Certain of our liquids and natural gas activities are subject to regulation by the FERC and various state authorities. Regulatory bodies exercise statutory authority over matters such as construction, rates and underlying accounting practices, and ratemaking agreements with customers.

Certain of our natural gas systems are subject to the provisions of Statement of Financial Accounting Standards ("SFAS") No. 71, *Accounting for the Effects of Certain Types of Regulation.* Accordingly, we record certain assets and liabilities that result from the regulated ratemaking process that would not be recorded for non-regulated entities under U.S. GAAP.

Revenue Recognition and the Estimation of Revenues and Cost of Natural Gas

Liquids

Revenues of our Liquids segment are primarily derived from two sources, interstate transportation of crude oil and liquid petroleum under tariffs regulated by the FERC and contract storage revenues related to our crude oil storage assets. The tariffs established for our interstate pipelines specify the amounts to be paid by shippers for service between receipt and delivery locations and the general terms and conditions of transportation services on the respective pipeline systems. We recognize revenue upon delivery of products to our customers, when pricing is determinable and collectibility is reasonably assured. We recognize contract storage revenues based on contractual terms under which customers pay for the option to use available storage capacity and/or a fee based on throughput volumes. We recognize revenues as storage services are rendered, pricing is determinable and collectibility is reasonably assured. In the Liquids segment, we generally do not own the crude oil and liquid petroleum that we transport or store, and therefore, we do not assume significant direct commodity price risk.

Natural Gas

We recognize revenue upon delivery of natural gas and NGLs to customers, when services are rendered, pricing is determinable and collectibility is reasonably assured. We derive revenue in our Natural Gas segment from the following types of arrangements:

Fee-Based Arrangements:

Under a fee-based contract, we receive a set fee for gathering, treating, processing and transporting raw natural gas and providing other similar services. These revenues correspond with the volumes and types of services provided and do not depend directly on commodity prices. Revenues of the Natural Gas segment that are derived from transmission services consist of reservation fees charged for transmission of natural gas on the FERC-regulated interstate natural gas transmission pipeline systems, while revenues from intrastate pipelines are generally derived from the bundled sales of natural gas and transmission services. Customers of the FERC-regulated natural gas pipeline systems typically pay a reservation fee each month to reserve capacity plus a nominal commodity charge based on actual transmission volumes.

Other Arrangements:

We also use other types of arrangements to derive revenues for our Natural Gas segment. These arrangements expose us to commodity price risk, which we substantially mitigate with offsetting physical purchases and sales and by the use of derivative financial instruments to hedge open positions. We will continue to hedge a significant amount of our commodity price risk to support the stability of our cash flows. Refer to Note 14 for more information about the derivative activities we use to mitigate this commodity price risk.

These other types of arrangements are categorized as follows:

- Percentage-of-Liquids Contracts—Under these contracts, we receive a negotiated percentage of NGLs and condensate extracted from natural gas that requires processing, which we then sell at market prices and retain as our fee. This contract structure is similar to percentage-of-proceeds arrangements discussed below except that we only receive a percentage of the NGLs and condensate.

- Keep-Whole Contracts—Under these contracts, we gather or purchase raw natural gas from the producer for processing. A portion of the gathered or purchased natural gas is consumed during processing. We extract and retain the NGLs produced during processing for our own account, which we sell at market prices. In instances where we purchase raw gas at the wellhead, we also sell for our own account at market prices, the resulting residue gas. In those instances when we gather and process raw natural gas for the account of the producer, we must return to the producer residue gas with an energy content equivalent to the original raw gas we received as measured in British thermal units, or Btu.

- Percentage-of-Index Contracts—Under these contracts, we purchase raw natural gas at a negotiated discount to an agreed upon index price. We then resell the natural gas, generally for the index price, keeping the difference as our fee.

- Percentage-of-Proceeds Contracts—Under the terms of these contracts, we receive a negotiated percentage of the natural gas and NGLs we process in the form of residue natural gas, NGLs, condensate and sulfur, which we then sell at market prices and retain as our fee.

Under the terms of each of these contract structures, we retain a portion of the natural gas and NGLs as our fee in exchange for providing these producers with our services. In order to protect our unitholders from volatility in our cash flows that can result from fluctuations in commodity prices, we enter into derivative financial instruments to effectively fix the sales price of the natural gas and NGLs we anticipate receiving under the terms of these contracts. As a result of entering into these derivative financial instruments, we have largely fixed the amount of cash that we will receive in the future when we sell the processed natural gas and NGLs, although the market price of these commodities will continue to fluctuate during that time.

Marketing

Revenues of our Marketing segment are derived from providing supply, transportation, balancing, storage and sales services for producers and wholesale customers on our natural gas pipelines, as well as other interconnected pipeline systems. Natural gas marketing activities are primarily undertaken to realize incremental revenues on natural gas purchased at the wellhead, and to provide other services valued by our customers. In general, natural gas purchased and sold by our Marketing business is priced at a published daily or monthly index price. Sales to wholesale customers typically incorporate a premium for managing their transmission and balancing requirements. Higher premiums and associated revenues result from transactions that involve smaller volumes or that offer greater service flexibility for wholesale customers. At the request of some customers, we will enter into long-term fixed price purchase or sales contracts with our customers and usually will enter into offsetting positions under the same or similar terms. We recognize revenues upon delivery of natural gas and NGLs to our customers, when services are rendered, pricing is determinable and collectibility is reasonably assured.

Estimation of Revenue and Cost of Natural Gas

For our natural gas and marketing businesses, we must estimate our current month revenue and cost of gas to permit the timely preparation of our consolidated financial statements. We generally cannot compile actual billing information nor obtain actual vendor invoices within a timeframe that would permit the recording of this actual data prior to preparation of the consolidated financial statements. As a result, we record an estimate each month for our operating revenues and cost of natural gas based on the best available volume and price data for natural gas delivered and received, along with a true-up of the prior month's estimate to equal the prior month's actual data. As a result, there is one month of estimated data recorded in our operating revenues and cost of natural gas for each of the years ended December 31, 2007, 2006 and 2005. We believe that the assumptions underlying these estimates will not be significantly different from actual amounts due to the routine nature of these estimates and the stability of our processes.

Cash and Cash Equivalents

Cash equivalents are defined as all highly marketable securities with maturities of three months or less when purchased. The carrying value of cash and cash equivalents approximates fair value because of the short term to maturity of these investments.

We extinguish liabilities when a creditor has relieved us of our obligation, which occurs when our financial institution honors a check that the creditor has presented for payment. Accordingly, obligations for which we have issued check payments that have not yet been presented to the financial institution of approximately $38.5 million at December 31, 2007 and $46.9 million at December 31, 2006 are included in Accounts payable and other on our Consolidated Statements of Financial Position.

Allowance for Doubtful Accounts

We establish provisions for losses on accounts receivable if we determine that we will not collect all or part of the outstanding balance. Collectibility is reviewed regularly and an allowance is established or adjusted, as necessary, using the specific identification method.

Inventory

Inventory includes product inventory and materials and supplies inventory. We record all product inventories at the lower of our cost as determined on a weighted average basis, or market. The product inventory consists of liquids and natural gas. Upon disposition, product inventory is recorded to Cost of natural gas at the weighted average cost of inventory, including any adjustments recorded to reduce inventory to market value.

Materials and supplies inventory is either used during operations and charged to operating expense as incurred, or used for capital projects and new construction, and capitalized to property, plant and equipment.

Oil Measurement Adjustments

Oil measurement adjustments occur as part of the normal operating conditions associated with our Liquids pipelines. The three types of oil measurement adjustments include:

- physical, which result from evaporation, shrinkage, differences in measurement between receipt and delivery locations and other operational incidents;
- degradation, which result from mixing at the interface between higher quality light crude oil and lower quality heavy crude oil in pipelines; and
- revaluation, which are a function of crude oil prices, the level of the carrier's inventory and the inventory positions of customers.

Difficulties are inherent in quantifying oil measurement adjustments because physical measurements of volumes are not practical, as products continuously move through our pipelines and virtually all of these pipelines are located underground. Quantifying oil measurement adjustments is especially difficult for us because of the length of the pipeline systems and the number of different grades of crude oil and types of crude oil products we carry. We utilize engineering-based models and operational assumptions to estimate product volumes in our systems and associated oil measurement adjustments. Material changes in our assumptions may result in revisions to our oil measurement estimates in the period determined.

Operational Balancing Agreements and Natural Gas Imbalances

To facilitate deliveries of natural gas and provide for operational flexibility, we have operational balancing agreements in place with other interconnecting pipelines. These agreements ensure that the volume of gas a shipper schedules for transportation between two interconnecting pipelines equals the volume actually delivered. If natural gas moves between pipelines in volumes that are more or less than the volumes the shipper previously scheduled, a gas imbalance is created. The imbalances are settled through periodic cash payments or repaid in kind through the receipt or delivery of natural gas in the future. Gas imbalances are recorded as accrued receivables and accrued purchases on our consolidated statements of financial position using the posted index prices, which approximate market rates, or our weighted average cost of gas.

Capitalization Policies, Depreciation Methods and Impairment of Property, Plant and Equipment

We capitalize expenditures related to property, plant and equipment, subject to a minimum rule, that have a useful life greater than one year for (1) assets purchased or constructed; (2) existing assets that are replaced, improved, or the useful lives have been extended; or (3) all land, regardless of cost. Acquisitions of new assets, additions, replacements and improvements (other than land) costing less than the minimum rule in addition to maintenance and repair costs, including any planned major maintenance activities, are expensed as incurred.

During construction, we capitalize direct costs, such as labor and materials, and other costs, such as direct overhead and interest at our weighted average cost of debt, and, in our regulated businesses that apply the provisions of Statement of Financial Accounting Standards No. 71, *Accounting for the Effects of Certain Types of Regulation*, or SFAS No. 71, an equity return component.

We categorize our capital expenditures as either core maintenance or enhancement expenditures. Core maintenance expenditures are necessary to maintain the service capability of our existing assets and include the replacement of system components and equipment that are worn, obsolete or near the end of their useful lives. Examples of core maintenance expenditures include valve automation programs, cathodic protection, zero-hour compression overhauls and electrical switchgear replacement programs. Enhancement expenditures improve the service capability of our existing assets, extend asset useful lives, increase capacities from existing levels, reduce costs or enhance revenues, and enable us to respond to governmental regulations and developing industry standards. Examples of enhancement expenditures include costs associated with installation of seals, liners and other equipment to reduce the risk of environmental contamination from crude oil storage tanks, costs of sleeving a major segment of a pipeline system following an integrity tool run, natural gas or crude oil well-connects, natural gas plants and pipeline construction and expansion.

Regulatory guidance issued by the FERC requires us to expense certain costs associated with implementing the pipeline integrity management requirements of the U.S. Department of Transportation's Office of Pipeline Safety. Under this guidance, beginning in January 2006, costs to 1) prepare a plan to implement the program, 2) identify high consequence areas, 3) develop and maintain a record keeping system and 4) inspect, test and report on the condition of affected pipeline segments to determine the need for repairs or replacements, are required to be expensed. We adopted this guidance prospectively in January 2006 for all our pipeline systems. Costs of modifying pipelines to permit in-line inspections, certain costs associated with developing or enhancing computer software and costs associated with remedial mitigation actions to correct an identified condition continue to be capitalized. We have historically capitalized initial in-line inspection programs, crack detection tool runs and hydrostatic testing costs conducted for the purposes of detecting manufacturing or construction defects. Beginning January 2006, costs of this nature are expensed as incurred, which is consistent with industry practice and the regulatory guidance issued by the FERC. However, we continue to capitalize initial construction hydrostatic testing cost and subsequent hydrostatic testing programs conducted for the purpose of increasing pipeline capacity in accordance with our capitalization policies. Also capitalized are certain costs such as sleeving or recoating existing pipelines, unless the expenditures are incurred as a single event and not part of a major program, in which case we expense these costs as incurred. Our adoption of the regulatory guidance did not significantly affect our financial position, results of operations or cash flows.

We record property, plant and equipment at its original cost, which we depreciate on a straight-line basis over the lesser of its estimated useful life or the estimated remaining lives of the crude oil or natural gas production in the basins the assets serve. Our determination of the useful lives of property, plant and equipment requires us to make various assumptions, including the supply of and demand for hydrocarbons in the markets served by our assets, normal wear and tear of the facilities, and the extent and frequency of maintenance programs. We routinely utilize consultants and other experts to assist us in assessing the remaining lives of the crude oil or natural gas production in the basins we serve.

We record depreciation using the group method of depreciation which is commonly used by pipelines, utilities and similar entities. Under the group method, for all segments, upon the disposition of property, plant and equipment, the cost less net proceeds is typically charged to accumulated depreciation and no gain or loss on disposal is recognized. However, when a separately identifiable group of assets, such as a stand-alone pipeline system is sold, we will recognize a gain or loss in our consolidated statements of income for the difference between the cash received and the net book value of the assets sold. Changes in any of our assumptions may alter the rate at which we recognize depreciation in our consolidated financial statements. At regular intervals, we retain the services of independent consultants to assist us with assessing the reasonableness of the useful lives we have established for the property, plant and equipment of our major systems. Based on the results of these regular assessments we may make modifications to the assumptions we use to determine our depreciation rates.

We evaluate the recoverability of our property, plant and equipment when events or circumstances such as economic obsolescence, the business climate, legal and other factors indicate we may not recover the carrying amount of the assets. We continually monitor our businesses, the market and business environments to identify indicators that could suggest an asset may not be recoverable. We evaluate the asset for recoverability by estimating the undiscounted future cash flows expected to be derived from operating the asset as a going concern. These cash flow estimates require us to make projections and assumptions for many years into the future for pricing, demand, competition, operating cost, contract renewals, and other factors. We recognize an impairment loss when the carrying amount of the asset exceeds its fair value as determined by quoted market prices in active markets or present value techniques if quotes are unavailable. The determination of the fair value using present value techniques requires us to make projections and assumptions regarding the probability of a range of outcomes and the rates of interest used in the present value calculations. Any changes we make to these projections and assumptions could result in significant revisions to our evaluation of recoverability of our property, plant and equipment and the recognition of an impairment loss in our consolidated statements of income.

Goodwill

Goodwill represents the excess of the purchase price over the fair value of net assets acquired in a business combination. Goodwill is allocated to two of our segments, Natural Gas and Marketing.

Goodwill is not amortized, but is tested for impairment annually based on carrying values as of the end of the second quarter, or more frequently if impairment indicators arise that suggest the carrying value of goodwill may not be recovered. Impairment occurs when the carrying amount of a reporting unit exceeds its fair value. At the time we determine that impairment has occurred, the carrying value of the goodwill is written down to its fair value. To estimate the fair value of the reporting units, we make estimates and judgments about future cash flows, as well as revenue, cost of sales, operating expenses, capital expenditures and net working capital based on assumptions that are consistent with our most recent long range plan, which we use to manage the business. We have not identified or recognized any goodwill impairments during the years ended December 31, 2007, 2006 or 2005.

Intangibles, Net

Intangibles, net, consist of customer contracts for the purchase and sale of natural gas and natural gas supply opportunities. We amortize these assets on a straight-line basis over the weighted average useful life of the underlying assets, representing the period over which the asset is expected to contribute directly or indirectly to our future cash flows.

We evaluate the carrying value of our intangible assets whenever certain events or changes in circumstances indicate that the carrying amount of these assets may not be recoverable. In assessing the recoverability of intangibles, we compare the carrying value to the undiscounted future cash flows the intangibles are expected to generate. If the total of the undiscounted future cash flows is less than the carrying amount of the intangibles, the intangibles are written down to their fair value. We did not identify nor recognize any impairment of our intangible assets for the years ended December 31, 2007, 2006, or 2005.

Other Assets

Other assets primarily include deferred financing costs, which we amortize on a straight-line basis over the life of the related debt to interest expense on our consolidated statements of income. Amortization of these costs on a straight-line basis approximates the amortization computed using the effective interest method.

Income Taxes

We are not a taxable entity for U.S. federal income tax purposes or for the majority of states that impose income tax. Taxes on our net income generally are borne by our unitholders through the allocation of taxable income. Our income tax expense results from the enactment, by the State of Texas, of a new state tax computed on our modified gross margin that we determined to be an income tax under the provisions of SFAS No. 109.

We recognize deferred income tax assets and liabilities for temporary differences between the relevant basis of our assets and liabilities for financial reporting and tax purposes. The impact of changes in tax legislation on deferred income tax liabilities and assets is recorded in the period of enactment.

Net income for financial statement purposes may differ significantly from taxable income of unitholders as a result of differences between the tax basis and financial reporting basis of assets and liabilities and the taxable income allocation requirements under our partnership agreement. The aggregate difference in the basis of our net assets for financial and tax reporting purposes cannot be readily determined because information regarding each partner's tax attributes in us is not available.

Derivative Financial Instruments

Our net income and cash flows are subject to volatility stemming from changes in interest rates on our variable rate debt and commodity prices of natural gas, NGL, condensate and fractionation margins (the relative price differential between NGL sales and the offsetting natural gas purchases). In order to manage the risks to unitholders, we use a variety of derivative financial instruments including futures, forwards, swaps, options and other financial instruments with similar characteristics to create offsetting positions to specific commodity or interest rate exposures. In accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* ("SFAS No. 133"), we record all derivative financial instruments on our consolidated statements of financial position at fair market value. We record the fair market value of our derivative financial instruments in the Consolidated Statements of Financial Position as current and long-term assets or liabilities on a net basis by counterparty. For those instruments that qualify for hedge accounting, the accounting treatment depends on the intended use and designation of each instrument. For our derivative financial instruments related to commodities that do not qualify for hedge accounting, the change in market value is recorded as a component of cost of natural gas in the consolidated statements of income. For our derivative financial instruments related to interest rates that do not qualify for hedge accounting, the change in fair market value is recorded as a component of Interest expense in the consolidated statements of income.

In implementing our hedging programs, we have established a formal analysis, execution and reporting framework that requires the approval of the board of directors of Enbridge Management or a committee of our senior management. We employ derivative financial instruments in connection with an underlying asset, liability or anticipated transaction and we do not use derivative financial instruments for speculative purposes.

Derivative financial instruments qualifying for hedge accounting treatment that we use can generally be divided into two categories: 1) cash flow hedges, or 2) fair value hedges. We enter into cash flow hedges to reduce the variability in cash flows related to forecasted transactions. We enter into fair value hedges to reduce the risk of changes in the value of recognized assets or liabilities.

Price assumptions we use to value the cash flow and fair value hedges can affect net income for each period. We use published market price information where available, or quotations from over-the-counter ("OTC") market makers to find executable bids and offers. The valuations also reflect the potential impact of liquidating our position in an orderly manner over a reasonable period of time under present market conditions, modeling risk, credit risk of our counterparties and operational risk. The amounts reported in our consolidated financial statements change quarterly as these valuations are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond our control.

At inception, we formally document the relationship between the hedging instrument and the hedged item, the risk management objectives, and the methods used for assessing and testing correlation and hedge effectiveness. We also assess, both at the inception of the hedge and on an on-going basis, whether the derivatives that are used in our hedging transactions are highly effective in offsetting changes in cash flows or the fair value of the hedged item. Furthermore, we regularly assess the creditworthiness of our counterparties to manage against the risk of default. If we determine that a derivative is no longer highly effective as a hedge, we discontinue hedge accounting prospectively by including changes in the fair value of the derivative in current earnings.

For cash flow hedges, changes in the fair market values of derivative financial instruments, to the extent that the hedges are determined to be highly effective, are recorded as a component of Accumulated other comprehensive income until the hedged transactions occur and are recognized in earnings. Any ineffective portion of a cash flow hedge's change in fair market value is recognized immediately in earnings. For fair value hedges, the change in fair market value of the financial instrument is determined each period and is taken into earnings. In addition, the change in the fair market value of the hedged item is also calculated and taken into earnings. To the extent that the two valuations offset, the hedge is effective and net earnings is not affected.

Our earnings are also affected by use of the mark-to-market method of accounting as required under GAAP for derivative financial instruments that do not qualify for hedge accounting. We use short-term, highly liquid derivative financial instruments such as basis swaps and other similar derivative financial instruments to economically hedge market price risks associated with inventories, firm commitments and certain anticipated transactions. However, these derivative financial instruments, do not qualify for hedge accounting treatment under SFAS No. 133, and thus the changes in fair value of these instruments are recorded on the balance sheet and through earnings (i.e., using the "mark-to-market" method) rather than being deferred until the firm commitment or anticipated transaction affects earnings. The use of mark-to-market accounting for financial instruments can cause non-cash earnings volatility due to changes in the underlying indices, primarily commodity prices. The fair market value of these derivative financial instruments is determined using price data from highly liquid markets such as the New York Mercantile Exchange, or NYMEX, OTC market makers, or other similar sources.

Commitments, Contingencies and Environmental Liabilities

We expense or capitalize, as appropriate, expenditures for ongoing compliance with environmental regulations that relate to past or current operations. Amounts for remediation of existing environmental contamination caused by past operations, which do not benefit future periods by preventing or eliminating future contamination, are expensed. Liabilities are recorded when environmental assessments indicate that remediation efforts are probable, and the costs can be reasonably estimated. Estimates of the liabilities are based on currently available facts, existing technology and presently enacted laws and regulations taking into consideration the likely effects of inflation and other factors. These amounts also consider prior experience in remediating contaminated sites, other companies' clean-up experience and data released by government organizations. These estimates are subject to revision in future periods based on actual costs or new information and are included on the balance sheet in other current and long-term liabilities at their undiscounted amounts. We evaluate recoveries from insurance coverage separately from the liability and, when recovery is probable, we record and report an asset separately from the associated liability in our consolidated financial statements.

We recognize liabilities for other contingencies when, after fully analyzing the available information, we determine it is either probable that an asset has been impaired, or that a liability has been incurred and the amount of impairment or loss can be reasonably estimated. When a range of probable loss can be estimated, we accrue the most likely amount, or if no amount is more likely than another, the minimum of the range of probable loss. We typically expense legal costs associated with loss contingencies as such costs are incurred.

Asset Retirement Obligations

We have legal obligations requiring us to decommission our offshore pipeline systems at retirement. In certain rate jurisdictions, we are permitted to include annual charges for removal costs in the regulated cost of service rates we charge our customers. Additionally, legal obligations exist for a minority of our onshore right-of-way agreements due to requirements or landowner options to compel us to remove the pipe at final abandonment. Sufficient data exists with certain onshore pipeline systems to reasonably estimate the cost of abandoning or retiring a pipeline system. However, in some cases, there is insufficient information to reasonably determine the timing and/or method of settlement for estimating the fair value of the asset retirement obligation. In these cases, the asset retirement obligation cost is considered indeterminate because there is no data or information that can be derived from past practice, industry practice, management's intent, or the asset's estimated economic life. Useful lives of most pipeline systems are primarily derived from available supply resources and ultimate consumption of those resources by end users. Variables can affect the remaining lives of the assets which preclude us from making a reasonable estimate of the asset retirement obligation. Indeterminate asset retirement obligation costs will be recognized in the period in which sufficient information exists to reasonably estimate potential settlement dates and methods.

We record a liability for the fair value of asset retirement obligations and conditional asset retirement obligations that we can reasonably estimate, on a discounted basis, in the period in which the liability is incurred. We collectively refer to asset retirement obligations and conditional asset retirement obligations as ARO. Typically we record an ARO at the time the assets are installed or acquired, if a reasonable estimate of fair value can be made. In connection with establishing an ARO, we capitalize the costs as part of the carrying value of the related assets. We recognize an ongoing expense for the interest component of the liability as part of depreciation expense resulting from changes in the value of the ARO due to the passage of time. We depreciate the initial capitalized costs over the useful lives of the related assets. We extinguish the liabilities for an ARO when assets are taken out of service or otherwise abandoned.

We did not record any additional AROs for the years ended December 31, 2007 and 2006. We recorded accretion expense of $0.2 million, $0.2 million and $0.5 million, respectively, in the consolidated statements of income for the years ended December 31, 2007, 2006 and 2005 for previously recorded asset retirement obligation liabilities.

No assets are legally restricted for purposes of settling our ARO for each of the years ended December 31, 2007 and 2006. Following is a reconciliation of the beginning and ending aggregate carrying amount of our ARO liabilities for each of the years ended December 31, 2007 and 2006:

	2007	2006
	(in millions)	
Balance at beginning of period	$ 3.8	$ 3.6
Disposal of KPC	(1.1)	—
Accretion expense	0.2	0.2
Balance at end of period	$ 2.9	$ 3.8

Recent Accounting Pronouncements Not Yet Adopted

Fair Value Measurements

In September 2006, the Financial Accounting Standards Board (FASB) issued FASB Statement No. 157, *Fair Value Measurements*. This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles (GAAP), and expands disclosures about fair value measurement. The statement is effective for fiscal years beginning after November 15, 2007, and with limited exceptions is to be applied prospectively as of the beginning of the fiscal year initially adopted. We expect to adopt the provisions of this statement prospectively beginning January 1, 2008. We do not expect our adoption of this pronouncement to materially affect our consolidated financial statements. However, our adoption of this pronouncement may affect our disclosures regarding derivative financial instruments and indebtedness.

In February 2007, the Financial Accounting Standards Board (FASB) issued FASB Statement No. 159, *The Fair Value Option for Financial Assets and Liabilities ("SFAS No. 159")*. This statement provides companies with an option to report certain financial assets and financial liabilities at fair value. The objective of SFAS No. 159 is to reduce the volatility in earnings caused by measuring related financial assets and financial liabilities differently without having to apply complex hedge accounting provisions. SFAS No. 159 also establishes presentation and disclosure requirements designed to facilitate comparisons between companies that choose different measurement attributes for similar types of assets and liabilities. The provisions of SFAS No. 159 are effective at the beginning of our first fiscal year that begins after November 15, 2007, as we have elected not to early adopt its provisions. We do not expect our adoption of SFAS No. 159 to have a material affect on our consolidated financial statements.

Business Combinations

In December 2007, the Financial Accounting Standards Board issued Statement No. 141(R), *Business Combinations*, which we refer to as SFAS No. 141(R). The new standard retains the fundamental requirements in FASB Statement No. 141, *Business Combinations*, that the acquisition method of accounting (previously referred to as the *purchase method*), be used for all business combinations and for an acquirer to be identified for each business combination. Among other items, SFAS No. 141(R) requires the following:

- Assets acquired, liabilities assumed and any noncontrolling interest in the acquiree at the acquisition date are to be measured at their fair values as of that date.

- Costs associated with effecting an acquisition and restructuring costs the acquirer was not obligated to incur are recognized separately from the business combination.

- Assets acquired and liabilities assumed arising from contractual contingencies as of the acquisition date are measured at their acquisition-date fair values.

- Noncontractual contingencies as of the acquisition date are measured at the acquisition-date fair values only if it is more likely than not that they meet the definition of an asset or liability in FASB Concepts Statement No. 6, *Elements of Financial Statements*.

- Assets and liabilities arising from contingencies are to be reported at the acquisition-date fair value absent new information about the possible outcome, however, when new information becomes available, liabilities are measured at the higher of the acquisition date fair value or the FASB Statement No. 5, *Accounting for Contingencies* (SFAS No. 5) amount while assets are measured at the lower of the acquisition date fair value or the best estimate of the future settlement amount.

- Goodwill as of the acquisition date is determined as the excess of the fair value of the consideration transferred plus the fair value of any noncontrolling interest plus the fair value of previously held equity interests less the fair values of the identifiable net assets acquired.

- Recognition of a gain in earnings attributable to the acquirer when the total acquisition date fair value of the identifiable net assets acquired exceed the fair value of the consideration transferred plus any noncontrolling interest in the acquiree.

- Contingent consideration at the acquisition date is measured at its fair value at that date.

- Retroactively recognize adjustments made during the measurement period (not more than one year from the acquisition date) as if the accounting had occurred on the acquisition date.

SFAS No. 141(R) applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008, and early adoption is not permitted. The provisions of this statement will require us to expense certain costs associated with acquisitions that were previously permitted to be capitalized which may affect our operating results in periods that we complete an acquisition.

Noncontrolling Interests

In December 2007, the Financial Accounting Standards Board issued FASB Statement No. 160, *Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51*, to establish accounting and reporting standards for the noncontrolling interest in a subsidiary and for deconsolidation of a subsidiary. Among other provisions, SFAS No. 160 requires the following:

- The ownership in subsidiaries held by parties other than the parent be presented in the consolidated statement of financial position within equity, but separate from the parent's equity.

- The amount of consolidated net income attributable to the parent and the noncontrolling interest be presented on the face of the consolidated statement of income.

- Changes in a parent's ownership interest while the parent retains its controlling financial interest in its subsidiary are accounted for as equity transactions.

- Any retained noncontrolling equity investment in a subsidiary that is deconsolidated be initially measured at fair value.

- Sufficient disclosures that clearly identify and distinguish between the interests of the parent and the interests of the noncontrolling owners.

SFAS No. 160 is effective for fiscal years, and interim periods within those years, beginning on or after December 15, 2008, and early adoption is prohibited. SFAS No. 160 requires prospective adoption as of the beginning of the fiscal year in which the provisions are initially applied, except for the presentation and disclosure requirements which shall be applied retrospectively for all periods presented. Our adoption of this standard will not have a material effect on our financial position or results of operations.

3. ACQUISITIONS AND DISPOSITIONS

We accounted for each of our completed acquisitions using the purchase method and recorded the assets acquired and liabilities assumed at their estimated fair market values as of the date of purchase. We have included the results of operations from each of these acquisitions in our earnings from the acquisition date.

2007 Disposition

KPC Disposition

In November 2007, we sold our Kansas pipeline system, or KPC, with a net asset value of approximately $100.4 million, including $9.2 million of goodwill, to an unrelated party for $133 million in cash, subject to adjustments for working capital items. KPC is an interstate natural gas transmission system, which serves the Wichita, Kansas and Kansas City, Kansas markets and includes approximately 1,120 miles of pipeline ranging in diameter from 4 to 12 inches, along with three compressor stations. The area in which KPC operates is not strategic to the ongoing central operations of our core Natural Gas segment assets. The operating results of the KPC system were not material to our consolidated operating results or those of our Natural Gas segment for the years ended December 31, 2007, 2006 and 2005. We recognized a gain of $32.6 million on the sale of KPC, which is presented in income from discontinued operations.

2006 Acquisitions

Oakhill Acquisition

In April 2006, we acquired, for $33.3 million in cash, an 80-mile natural gas pipeline that is complementary to our existing East Texas system. This pipeline provides approximately 100 million cubic feet per day, or MMcf/d, of additional transportation capacity and interconnects with approximately 65 central receipt points.

The purchase price and the allocation to assets acquired and liabilities assumed are as follows in millions of dollars:

Purchase Price:		
Cash paid, including transaction costs	$	33.3
Allocation of purchase price:		
Property, plant and equipment, including construction in progress	$	13.0
Intangibles		12.8
Goodwill		7.5
Total	$	33.3

2005 Acquisitions and Dispositions

North Texas Natural Gas System

In January 2005, we acquired natural gas gathering and processing assets in north Texas for $164.6 million in cash, including transaction costs of $0.5 million. The assets we acquired serve the Fort Worth Basin, which is mature, but experiencing minimal production decline rates and include:

- 2,200 miles of gas gathering pipelines; and
- four processing plants with aggregate processing capacity of 121 MMcf/d of natural gas.

The system provides cash flow primarily from purchasing raw natural gas from producers at the wellhead, processing the natural gas and then selling the natural gas liquids and residue natural gas streams. We included the assets and results of operations in our Natural Gas segment from the acquisition date.

We allocated the purchase price of the assets acquired and liabilities assumed as follows (in millions):

Purchase Price:		
Cash paid, including transaction costs	$	164.6
Allocation of purchase price:		
Property, plant and equipment, including construction in progress	$	151.6
Intangibles, including contracts		14.3
Current liabilities		(0.9)
Contingent liabilities		(0.4)
Total	$	164.6

Other 2005 Acquisitions

In June 2005, we acquired for $20.1 million in cash, a natural gas pipeline and related facilities consisting of 92 miles of 20-inch diameter pipeline that extends from Pampa, Texas into western Oklahoma and has interconnects with our Anadarko system. We integrated this pipeline into our existing Anadarko system and have included the assets and operating results in our Natural Gas segment from the date of acquisition. The purchase price for this acquisition was allocated to property, plant and equipment for $19.1 million and goodwill for $1.0 million. We also acquired other gathering and processing assets during 2005 that are complementary to our existing natural gas systems for cash totaling approximately $1.7 million.

Sale of Gathering and Processing Assets

In December 2005, we sold for $105.4 million in cash, a processing plant and related facilities and other gathering and processing assets located in our East and South Texas systems with a carrying value of approximately $86.9 million. We incurred selling costs of approximately $0.4 million and recognized a gain on the sale of approximately $18.1 million. The facilities we sold represent non-strategic assets within our Natural Gas segment. In connection with this sale, we paid approximately $16.3 million to settle natural gas collars on 2,000 Million British Thermal units per day, or MMBtu/d, associated with the natural gas produced by these assets and entered into offsetting derivatives at market to close out derivatives previously classified as hedges of 273 Barrels per day, or Bpd, of NGL produced by these assets. We had previously recorded unrealized losses associated with the natural gas collars that were realized upon settlement. Refer to Note 14 for additional discussion regarding our derivative activities.

4. NET INCOME PER LIMITED PARTNER UNIT

We compute net income per limited partner unit by dividing net income, after deducting our allocation to the General Partner, by the weighted average number of our limited partner units outstanding. The General Partner's allocation is equal to an amount based upon its general partner interest, adjusted to reflect an amount equal to its incentive distributions and an amount required to reflect depreciation on the General Partner's historical cost basis for assets contributed on formation of the

Partnership. We have no dilutive securities, therefore basic and diluted earnings per unit amounts are equal. Net income per limited partner unit was determined as follows:

	Year ended December 31,		
	2007	2006	2005
	(in millions, except per unit amounts)		
Income from continuing operations	$ 216.9	$ 284.9	$ 89.2
Income from discontinued operations	32.6	—	—
Net income	$ 249.5	$ 284.9	$ 89.2
Allocations to the General Partner:			
Income from continuing operations	$ (4.3)	$ (5.7)	$ (1.8)
Incentive distributions to General Partner	(32.5)	(25.1)	(21.6)
Historical cost depreciation adjustments	(0.2)	(0.1)	(0.1)
	(37.0)	(30.9)	(23.5)
Income from discontinued operations	(0.7)	—	—
	$ (37.7)	$ (30.9)	$ (23.5)
Allocations to limited partner units			
Income from continuing operations	$ 179.9	$ 254.0	$ 65.7
Income from discontinued operations	31.9	—	—
	$ 211.8	$ 254.0	$ 65.7
Basic and diluted earnings per limited partner unit			
Income from continuing operations	$ 2.08	$ 3.62	$ 1.06
Income from discontinued operations	0.37	—	—
Net income per limited partner unit (basic and diluted)	$ 2.45	$ 3.62	$ 1.06
Weighted average units outstanding	86.3	70.2	62.1

5. INVENTORY

Inventory is comprised of the following:

	December 31,	
	2007	2006
	(in millions)	
Material and supplies	$ 3.9	$ 3.8
Liquids inventory	6.7	9.9
Natural gas and natural gas liquids inventory	100.0	103.4
	$ 110.6	$ 117.1

Our inventory at December 31, 2007 is net of charges totaling $4.5 million we recorded in 2007 to reduce the cost basis of our natural gas inventory to reflect market value. Our inventory at December 31, 2006 is net of charges totaling $17.7 million we recorded in 2006 to reduce the cost basis of our natural gas inventory to reflect market value. The lower of cost or market adjustments are included in the Cost of natural gas of our Natural Gas and Marketing segments on our consolidated statements of income.

6. PROPERTY, PLANT AND EQUIPMENT

Property, Plant and Equipment is comprised of the following:

	Depreciation Rates[1]	December 31, 2007	December 31, 2006
		(in millions)	
Land	—	$ 14.3	$ 14.3
Rights-of-way	1.5% - 6.4%	345.8	298.6
Pipeline	1.5% - 7.0%	2,703.2	2,320.8
Pumping equipment, buildings and tanks	1.5% - 14.3%	854.7	747.4
Compressors, meters, and other operating equipment	1.5% - 20.0%	536.1	418.1
Vehicles, office furniture and equipment	1.4% - 33.3%	123.3	112.4
Processing and treating plants	2.7% - 4.0%	200.4	86.4
Construction in progress	—	1,813.9	733.6
Total property, plant and equipment		6,591.7	4,731.6
Accumulated depreciation		(1,036.8)	(906.7)
Net property, plant and equipment		$ 5,554.9	$ 3,824.9

(1) We have assets included in the above table that are highly depreciated, which yield depreciation rates that suggest these assets have significant remaining useful lives, but in fact have little remaining net book value in relation to their expected service lives.

Based on third-party studies commissioned by management, we implemented revised depreciation rates for the Lakehead system effective January 1, 2006, and the Anadarko, North Texas and East Texas systems effective August 1, 2005. We reduced the annual composite rate, representing the expected remaining service lives of the system assets, from 3.20% to 2.63% for our Lakehead system and from 4.0% to 3.4% for our Anadarko, North Texas and East Texas systems. As a result, our depreciation expense for the years ended December 31, 2006 and 2005, respectively, was approximately $14.5 million and $2.5 million lower than if these rates had not been reduced. Additionally, effective July 1, 2006, we increased the annual composite rates on three of our FERC-regulated pipelines, representing reductions to the expected remaining service lives of our AlaTenn, KPC, and Midla systems. These increases resulted in approximately $1.3 million and $2.6 million of additional depreciation in 2006 and 2007, respectively.

7. GOODWILL

The changes in the carrying amount of goodwill for each of the years ended December 31, 2007 and 2006 are as follows:

	Liquids	Natural Gas	Marketing	Corporate	Total
			(in millions)		
December 31, 2005	$ —	$ 237.8	$ 20.4	$ —	$ 258.2
Acquisition	—	7.5	—	—	7.5
December 31, 2006	—	245.3	20.4	—	265.7
Disposition	—	(9.2)	—	—	(9.2)
December 31, 2007	$ —	$ 236.1	$ 20.4	$ —	$ 256.5

In November 2007 we sold our KPC assets to an unrelated third party for $133 million. In connection with the sale, we disposed of $9.2 million of goodwill associated with this business which we reduced the gain we realized from the sale.

We completed our annual goodwill impairment test using data at June 30, 2007. To estimate the fair value of our reporting units we made estimates and judgments about future cash flows, as well as revenue, cost of sales, operating expenses, capital expenditures, and net working capital based on assumptions that are consistent with the long-range plans we use to manage our businesses. Based on the results of our impairment analysis, we determined that the fair value of each reporting unit exceeded its respective carrying amount, including goodwill. As a result, no goodwill impairment existed in any of our reporting units. We have not observed any events or circumstances subsequent to our analysis that would, more likely than not, reduce the fair value of our reporting units below the carrying amounts as of December 31, 2007.

8. INTANGIBLES

The following table provides the gross carrying value, accumulated amortization and activity affecting these balances for each of our major classes of intangible assets.

	Gross Carrying Amount				Accumulated Amortization				
	Customer Contracts	Natural Gas Supply Opportunities	Other	Intangible Assets Gross	Customer Contracts	Natural Gas Supply Opportunities	Other	Accumulated Amortization Gross	Intangible Assets, Net
	(in millions)								
December 31, 2004	$ 31.1	$ 48.1	$ —	$ 79.2	$ (3.3)	$ (1.9)	$ —	$ (5.2)	$ 74.0
Additions	14.3	—	4.3	18.6	—	—	—	—	18.6
Dispositions	(2.2)	—	—	(2.2)	0.3	—	—	0.3	(1.9)
Amortization	—	—	—	—	(1.7)	(2.0)	(0.1)	(3.8)	(3.8)
December 31, 2005	43.2	48.1	4.3	95.6	(4.7)	(3.9)	(0.1)	(8.7)	86.9
Additions	12.8	—	2.4	15.2	—	—	—	—	15.2
Amortization	—	—	—	—	(2.2)	(1.9)	(0.2)	(4.3)	(4.3)
December 31, 2006	56.0	48.1	6.7	110.8	(6.9)	(5.8)	(0.3)	(13.0)	97.8
Additions	—	—	2.9	2.9	—	—	—	—	2.9
Dispositions(1)	(5.8)	—	—	(5.8)	1.1	—	—	1.1	(4.7)
Amortization	—	—	—	—	(2.2)	(1.9)	(0.4)	(4.5)	(4.5)
December 31, 2007	$ 50.2	$ 48.1	$ 9.6	$ 107.9	$ (8.0)	$ (7.7)	$ (0.7)	$ (16.4)	$ 91.5

(1) We disposed of customer contract intangibles of $4.7 million in connection with the sale of KPC.

Our customer contracts are comprised entirely of natural gas purchase and sale agreements associated with our Natural Gas and Marketing segments. We amortize our customer contracts on a straight-line basis over the weighted average useful life of the underlying reserves at the time of acquisition, which approximates 25 years.

We obtained the natural gas supply opportunities in conjunction with the 2003 North Texas system acquisition and relate entirely to our Natural Gas segment. The value of the intangible asset was determined by a third party appraisal and it represents the fair value associated with growth opportunities present in the Barnett Shale producing zone. We are amortizing the natural gas supply opportunities over the weighted average estimated useful life of the underlying reserves at the time of the acquisition, which approximates 25 years.

Our other column is comprised of contributions we made in aid of construction for our Natural Gas and Liquids business. We made contributions to third parties for construction of electrical infrastructure to provide utility services for our Lakehead system and for interconnections between our natural gas systems and third-party pipelines and the related measurement equipment.

We estimate the aggregate amortization expense associated with our intangibles for each of the five succeeding years through December 31, 2012 to approximate $4.6 million.

9. DEBT

The following table presents the primary components of our outstanding indebtedness and the weighted average interest rates associated with each component at the end of each period presented, before the effect of our interest rate hedging activities as discussed in Notes 13 and 14:

		December 31,			
		2007		2006	
	Maturity	Rate	Dollars	Rate	Dollars
		(dollars in millions)			
First Mortgage Notes	2011	9.15%	$ 124.0	9.15%	$ 155.0
Credit Facility	2012	5.22%	400.0	—	—
Commercial Paper[(1)]	2012	5.36%	268.5	5.45%	443.7
Senior Notes	2009-2034	5.69%	1,702.1	5.74%	1,498.4
Junior Subordinated Notes	2067	8.05%	399.3	—	—
			2,893.9		2,097.1
Current maturities and short-term debt			(31.0)		(31.0)
Long-term debt			$ 2,862.9		$ 2,066.1

(1) Individual issuances of commercial paper generally mature in 90 days or less, but are supported by our credit facility and are therefore considered long-term debt.

First Mortgage Notes

The First Mortgage Notes ("Notes") are collateralized by a first mortgage lien on substantially all of the property, plant and equipment of the Enbridge Energy, Limited Partnership, (the "OLP"), and are due and payable in equal annual installments of $31.0 million until their maturity in 2011. Property, plant and equipment, net, associated with the OLP was $2,555.5 million and $1,495.1 million at December 31, 2007 and 2006, respectively. The Notes contain various restrictive covenants applicable to us, and restrictions on the incurrence of additional indebtedness, including compliance with certain debt issuance tests. We believe these restrictions will not negatively impact our ability to finance future expansion projects. Under the Notes agreements, we cannot make cash distributions more frequently than quarterly in an amount not to exceed Available Cash (see Note 10) for the immediately preceding calendar quarter. We would be required to pay a redemption premium pursuant to the Note agreements should we elect to repay the Notes prior to their stated maturity.

Under the terms of the Notes, we are required to establish, at the end of each quarter, a debt service reserve. This reserve includes an amount equal to 50% of the prospective Notes interest payments for the immediately following quarter and an amount for Note sinking fund repayments. At December 31, 2007 and 2006, there was no required debt service reserve, as we have made all required interest and sinking fund payments.

Credit Facility

On April 4, 2007 we entered into the Second Amended and Restated Credit Agreement (Credit Facility) which among other things: (i) increased the maximum principal amount of credit available to us at any one time from $1 billion to $1.25 billion; (ii) gave us the right to request increases in the maximum principal amount of credit available at any one time from $1.25 billion to $1.5 billion; (iii) eliminated the sublimit on letters of credit; (iv) provided for a five-year facility that matures April 4, 2012 and grants us the option to request annual extensions of maturity and a one-year term out period upon maturity; (v) modified our leverage ratio to include in the calculations of EBITDA (as defined in the Second Amended and Restated Credit Agreement) pro forma adjustments for material projects and to exclude from the calculation of Consolidated Funded Debt (as defined in the Second Amended and Restated Credit Agreement) certain amounts of preferred securities and subordinated debt that we or our designated subsidiaries may issue in the future; and (vi) eliminated our coverage ratio financial covenant. Our Credit Facility contains restrictive covenants that require us to maintain a maximum leverage ratio of 5.50 to 1.0 for periods ending on or before March 31, 2009; a ratio of 5.25 to 1.0 thereafter, for periods ending on or before March 31, 2010; and a ratio of 5.00 to 1.0 for periods ending June 30, 2010 and following. Our Credit Facility continues to support our commercial paper program.

At December 31, 2007, our leverage ratio was approximately 3.6. Our Credit Facility also places limitations on the debt that our subsidiaries may incur directly. Accordingly, it is expected that we will provide debt financing to our subsidiaries as necessary.

At December 31, 2007, we had $400 million outstanding under our Credit Facility at a weighted average interest rate of 5.22% and letters of credit totaling $159.7 million. The amounts we may borrow under the terms of our Credit Facility are reduced by the principal amount of our commercial paper issuances and the balance of our letters of credit outstanding. At December 31, 2007 and 2006, we could borrow $420.3 million and $495.7 million, respectively, under the terms of our Credit Facility, determined as follows:

	2007	2006
	(in millions)	
Total credit available under Credit Facility	$ 1,250.0	$ 1,000.0
Less: Amounts outstanding under Credit Facility	(400.0)	—
Balance of letters of credit outstanding	(159.7)	(59.3)
Principal amount of commercial paper issuances	(270.0)	(445.0)
Total amount we could borrow at December 31, 2007	$ 420.3	$ 495.7

Individual borrowings under the terms of our Credit Facility generally become due and payable at the end of each contract period, typically a period of three months or less. We have the option to repay these amounts on a non-cash basis by net settling with the parties to our Credit Facility by contemporaneously borrowing at the then current rate of interest and repaying the amounts due. During the year ended December 31, 2007, we net settled borrowings of approximately $180 million on a non-cash basis. During the year ended December 31, 2006, we did not net settle any borrowings under our Credit Facility and we net settled $565 million during the year ended December 31, 2005, on a non-cash basis.

Commercial Paper Program

We have a commercial paper program that provides for the issuance of up to $600 million of commercial paper that is supported by our Credit Facility. We access the commercial paper market primarily to provide temporary financing for our operating activities, capital expenditures and acquisitions, at rates that are generally lower than the rates available under our Credit Facility. At December 31, 2007 and 2006, respectively, we had $268.5 million and $443.7 million of commercial paper outstanding, net of unamortized discount of $1.5 million and $1.3 million, at weighted average interest rates of 5.36% and

5.45%. At December 31, 2007 and 2006, respectively, we could issue an additional $330 million and $155 million in principal amount under our commercial paper program.

We have the ability and intent to refinance all of our commercial paper obligations on a long-term basis under our unsecured long-term Credit Facility. Accordingly, such amounts have been classified as long-term debt in our accompanying consolidated statement of financial position.

Senior Notes

All of our Senior Notes, other than the Zero Coupon Notes discussed below, pay interest semi-annually and have varying maturities and terms as presented in the following table. The Senior Notes do not contain any covenants restricting the issuance of additional indebtedness and rank equally with all of our other existing and future unsecured and unsubordinated indebtedness. The interest rates set forth in this table represent the interest rates as set forth on the face of each note agreement without consideration to any discount or interest rate hedging activities.

	Interest Rate	December 31, 2007	December 31, 2006
		(in millions)	
Senior Notes due 2009	4.000%	$ 200.0	$ 200.0
Senior Notes due 2012	7.900%	100.0	100.0
Senior Notes due 2013	4.750%	200.0	200.0
Senior Notes due 2014	5.350%	200.0	200.0
Senior Notes due 2016	5.875%	300.0	300.0
Senior Notes due 2018	7.000%	100.0	100.0
Senior Notes due 2028	7.125%	100.0	100.0
Senior Notes due 2033	5.950%	200.0	200.0
Senior Notes due 2034	6.300%	100.0	100.0
Senior, unsecured zero coupon notes due 2022	5.358%	203.6	—
		1,703.6	1,500.0
Unamortized Discount		(1.5)	(1.6)
		1,702.1	1,498.4

Zero Coupon Senior Notes

In August 2007, we received net proceeds of approximately $200 million from a private placement of our senior, unsecured zero coupon notes due 2022 (the "Zero Coupon Notes"), which at maturity will be payable in the aggregate principal amount of $442 million. We initially recorded the Zero Coupon Notes in long-term debt at the amount of proceeds we received from the private placement, which we refer to as the issue price. The carrying amount at December 31, 2007 includes $3.6 million associated with the accretion of interest we recognized as interest expense during the period. The Zero Coupon Notes are scheduled to mature on August 28, 2022, although they may be called by the note holders prior to the scheduled maturity date on August 28 of any year commencing on August 28, 2009, at a price equal to the then accreted value of the called Zero Coupon Notes. The Zero Coupon Notes have a yield of 5.36% on a semi-annual compound basis and rank equally in right of payment to all of our existing and future senior indebtedness, as set forth in our senior indenture. We used the net proceeds from this private placement to repay a portion of our outstanding commercial paper and Credit Facility borrowings that we had previously incurred to fund a portion of our capital expansion projects.

Junior Subordinated Notes

In September 2007, we issued and sold $400 million in principal amount of our fixed/floating rate, junior subordinated notes due 2067, which we refer to as the Junior Notes. We received proceeds of approximately $393 million, net of underwriting discounts, commissions and offering expenses. We used the net proceeds to temporarily reduce a portion of our outstanding commercial paper and Credit Facility borrowings that we had previously incurred to finance a portion of our capital expansion projects.

The Junior Notes represent our unsecured obligations that are subordinate in right of payment to all of our existing and future senior indebtedness. The Junior Notes bear interest at a fixed annual rate of 8.05%, exclusive of any discounts or interest rate hedging activities, from September 27, 2007 to October 1, 2017, payable semi-annually in arrears on April 1 and October 1 of each year beginning April 1, 2008. After October 1, 2017, the Junior Notes will bear interest at a variable rate equal to the three-month LIBOR for the related interest period increased by 3.7975%, payable quarterly in arrears on January 1, April 1, July 1 and October 1 of each year beginning January 1, 2018. We may elect to defer interest payments on the Junior Notes for up to ten consecutive years on one or more occasions, but not beyond the final repayment date. Until paid, any interest we elect to defer will bear interest at the prevailing interest rate, compounded semi-annually during the period the Junior Notes bear interest at the fixed annual rate and quarterly during the period that the Junior Notes bear interest at a variable annual rate.

The Junior Notes do not restrict our ability to incur additional indebtedness. However, with limited exceptions, during any period we elect to defer interest payments on the Junior Notes, we cannot make distribution payments or liquidate any of our equity securities, nor can we or our subsidiaries make any principal and interest payments for any debt that ranks equally with or junior to the Junior Notes.

The scheduled maturity date for the Junior Notes is initially October 1, 2037, but we may extend the maturity date up to two times, on October 1, 2017 and October 1, 2027, in each case for an additional ten-year period. As a result, the scheduled maturity date may be extended to October 1, 2047 or October 1, 2057. Our obligation to repay the Junior Notes on the scheduled maturity date is limited by an agreement we refer to as the Replacement Capital Covenant, which we entered into in connection with our offering of the Junior Notes, but not as part of the Junior Notes. The Replacement Capital Covenant limits the types of financing sources we can use to repay the Junior Notes. We are required to repay the Junior Notes on the scheduled maturity date only to the extent the principal amount repaid does not exceed proceeds we have received from the issuance and sale of securities, that, among other attributes defined in the Replacement Capital Covenant, have characteristics that are the same or more equity-like than the Junior Notes. We refer to the securities that meet this characterization as qualifying capital securities. If we do not receive sufficient proceeds from the sale of qualifying capital securities to repay the Junior Notes by the scheduled maturity date, we must use our commercially reasonable efforts to raise sufficient proceeds from the sale of qualifying capital securities to permit repayment of the Junior Notes on the following quarterly interest payment date, and on each subsequent quarterly interest payment date until the Junior Notes are paid in full. Regardless of the amount of qualifying capital securities that we have issued and sold, the final repayment date is initially October 1, 2067. We may extend the final repayment date for an additional ten-year period on October 1, 2017, and as a result the final repayment date may be extended to October 1, 2077. We may extend the scheduled maturity date whether or not we also extend the final repayment date, and we may extend the final repayment date whether or not we extend the scheduled maturity date.

We may redeem the Junior Notes in whole at any time, or in part from time, prior to October 1, 2017, for a "make-whole" redemption price, and thereafter at a redemption price equal to the principal amount plus accrued and unpaid interest on the Junior Notes. We may also redeem the Junior Notes prior to October 1, 2017 in whole, but not in part, upon the occurrence of certain tax or rating agency events at specified redemption prices. Our right to optionally redeem the Junior Notes is also limited by the Replacement Capital Covenant, which limits the types of financing sources we can use to redeem the Junior Notes in the same manner as to repay the Junior Notes, as discussed in the above paragraph.

Interest

For the years ended December 31, 2007, 2006, and 2005, our interest cost is comprised of the following:

	Year Ended December 31,		
	2007	2006	2005
	(dollars in millions)		
Interest expense	$ 99.8	$ 110.5	$ 107.7
Interest capitalized	47.4	10.7	4.0
Interest cost incurred	$ 147.2	$ 121.2	$ 111.7
Interest paid	$ 125.8	$ 109.7	$ 101.7

Maturities of Third Party Debt

The scheduled maturities of outstanding third party debt, excluding the market value of interest rate swaps, at December 31, 2007, are summarized as follows in millions:

2008	$ 31.0
2009	434.6
2010	31.0
2011	31.0
2012	770.0
Thereafter	1,600.0
Total	$ 2,897.6

10. PARTNERS' CAPITAL

Our capital accounts are comprised of a two percent general partner interest and 98 percent limited partner interests. The limited partner interests are comprised of Class A common units, Class B common units, Class C units, and i-units. The limited partners have limited rights of ownership as provided for under our partnership agreement and, as discussed below, the right to participate in our distributions. The General Partner manages our operations, subject to a delegation of control agreement with Enbridge Management, and participates in the Partnership's distributions, including certain incentive income distributions.

Class A common units

The following table presents the net proceeds from our Class A common unit issuances for each of the years ended December 31, 2007, 2006 and 2005. The proceeds from each of our offerings were generally used to repay issuances of commercial paper or amounts outstanding under our credit facilities, which we initially borrowed to finance our capital expansion projects and acquisitions, or to repay other outstanding obligations. Any proceeds we received in excess of amounts used to repay issuances of commercial paper and credit facility borrowings were temporarily invested for use in future periods to fund additional expenditures associated with our capital expansion projects.

Issuance Date	Number of Class A Common units Issued		Offering Price per Class A Common unit		Net Proceeds to the Partnership(1)		General Partner Contribution(2)		Net Proceeds Including General Partner Contribution
					(in millions, except per unit amounts)				
2007									
May	5,300,000	$	58.000	$	301.9	$	6.1	$	308.0
2006									
We did not issue any Class A common units during 2006									
2005									
December	136,200	$	46.000	$	6.0	$	0.2	$	6.2
November	3,000,000	$	46.000		132.1		2.8		134.9
February	2,506,500	$	49.875		124.8		2.7		127.5
2005 Totals	5,642,700			$	262.9	$	5.7	$	268.6

(1) Net of underwriters' fees and discounts, commissions and issuance expenses.

(2) Contributions made by the General Partner to maintain its 2% general partner interest.

Class B common units

Our outstanding Class B common units are held entirely by our general partner and have rights similar to our Class A common units except that they are not currently eligible for trading on the NYSE.

Class C units

In April 2007, we issued and sold 4.7 million Class C units at a price of $53.11 per Class C unit to CDP Infrastructure Fund G.P. ("CDP"), 0.9 million Class C units to Tortoise Infrastructure Corporation and 0.3 million Class C units to Tortoise Energy Capital Corporation. We sold the Class C units in a private transaction exempt from registration under Section 4(2) of the Securities Act of 1933, as amended. We received proceeds of approximately $314.4 million, net of expenses associated with the private placement. In addition, our general partner contributed approximately $6.4 million to us to maintain its two percent general partner interest. We used the proceeds from this offering partially to reduce outstanding commercial paper we previously issued to finance a portion of our capital expansion program.

In August 2006, we issued and sold 5.4 million Class C units, representing a new class of limited partner interest, to our general partner and 5.4 million Class C units to CDP for a purchase price of $46.00 per unit in a private transaction exempt from registration under Section 4(2) of the Securities Act of 1933, as amended. We received proceeds of approximately $500 million, net of expenses associated with the private placement. Additionally, our general partner contributed approximately $10 million to maintain its two percent general partner interest.

i-units

The i-units are a separate class of our limited partner interests, all of which are owned by Enbridge Management and are not publicly traded.

Enbridge Management, as the owner of our i-units, votes together with the holders of the common units as a single class. However, the i-units vote separately as a class on the following matters:

- Any proposed action that would cause us to be treated as a corporation for U.S. federal income tax purposes;
- Amendments to our partnership agreement that would have a material adverse effect on the holder of our i-units, unless, under our partnership agreement, the amendment could be made by our general partner without a vote of holders of any class of units;
- The removal of our general partner and the election of a successor general partner; and
- The transfer by our general partner of its general partner interest to a non-affiliated person that requires a vote of holders of units under our partnership agreement and the admission of that person as a general partner.

In all cases, Enbridge Management will vote or refrain from voting its i-units in the same manner that owners of Enbridge Management's shares vote or refrain from voting their shares. Furthermore, under the terms of our partnership agreement, we agree that we will not, except in liquidation, make a distribution on an i-unit other than in additional i-units or a security that has in all material respects the same rights and privileges as the i-units.

Distributions

Our partnership agreement requires us to distribute 100 percent of our "Available Cash", which is generally defined in our partnership agreement as the sum of all cash receipts and net additions to reserves for future cash requirements less cash disbursements and amounts retained by us. Enbridge Management, as delegate of our general partner under the delegation of control agreement, computes the amount of our "Available Cash." Typically, the General Partner and owners of our common units will receive distributions in cash. However, we also retain reserves to provide for the proper conduct of our business and as necessary to comply with the terms of our agreements or obligations (including any reserves required under debt instruments for future principal and interest payments and for future capital expenditures). We make distributions to our partners approximately 45 days following the end of each calendar quarter in accordance with their respective percentage interests.

Our general partner is granted discretion by our partnership agreement, which discretion has been delegated to Enbridge Management, subject to the approval of the General Partner in certain cases, to establish, maintain and adjust reserves for future operating expenses, debt service, maintenance capital expenditures, and distributions for the next four quarters. These reserves are not restricted by magnitude, but only by type of future cash requirements with which they can be associated. When Enbridge Management determines our quarterly distributions, it considers current and expected reserve needs along with current and expected cash flows to identify the appropriate sustainable distribution level.

Distributions of our Available Cash are generally made 98.0 percent to holders of our limited partner units and two percent to our general partner. However, distributions are subject to the payment of incentive distributions to the General Partner to the extent that certain target levels of distributions to the unitholders are achieved. The incremental incentive distributions payable to the General Partner are 15.0 percent, 25.0 percent and 50.0 percent of all quarterly distributions of Available Cash that exceed target levels of $0.59, $0.70, and $0.99 per limited partner units. As set forth in our partnership agreement, we will not make cash distributions on our i-units, but instead, will distribute additional i-units such that the cash is retained and used in our business. Similarly, until August 15, 2009, we will distribute additional Class C units to the holders of our Class C units in lieu of cash distributions, which will be retained and used in our business. Further, we retain an additional amount equal to two percent of the i-unit and Class C unit distributions from the General Partner to maintain its two percent general partner interest in us.

Enbridge Management, as owner of the i-units, does not receive distributions in cash. Instead, each time that we make a cash distribution to the General Partner and the holders of our common units, the number of i-units owned by Enbridge Management and the percentage of our total units owned by Enbridge Management will increase automatically under the provisions of our partnership agreement with the result that the number of i-units owned by Enbridge Management will equal the number of Enbridge Management's listed and voting shares that are then outstanding. The amount of this increase in i-units is determined by dividing the cash amount distributed per common unit by the average price of one of Enbridge Management's listed shares on the NYSE for the 10-trading day period immediately preceding the ex-dividend date for Enbridge Management's shares multiplied by the number of shares outstanding on the record date. The cash equivalent amount of the additional i-units is treated as if it had actually been distributed for purposes of determining the distributions to be made to the General Partner.

Until August 15, 2009, in lieu of cash distributions, the holders of our Class C units will receive quarterly distributions of additional Class C units with a value equal to the quarterly cash distributions we pay to the holders of our Class A and Class B common units, which we collectively refer to as common units. The number of additional Class C units we will issue is determined by dividing the quarterly cash distribution per unit we pay on our common units by the average market price of a Class A common unit as listed on the New York Stock Exchange for the 10-trading day period immediately preceding the ex-dividend date for our Class A common units multiplied by the number of Class C units outstanding on the record date. As a result, the number of Class C units and the percentage of our total units owned by holders of the Class C units will increase automatically under the provisions of our partnership agreement. The cash equivalent amount of the additional Class C units is treated as if it had actually been distributed for purposes of determining the distributions to be made to the General Partner.

After August 15, 2009, the holders of our Class C units will receive quarterly cash distributions equal to those paid to the holders of our common units. Subject to the approval of holders of our outstanding units in accordance with the then-existing requirements of the principal national securities exchange on which the Class A common units are listed, the Class C units will convert into Class A common units on a one-for-one basis. If our unitholders do not approve the conversion, the holders of our Class C units will receive quarterly cash distributions equal to 115 percent of those paid to the holders of our common units. Prior to conversion, holders of our Class C units will not be entitled to receive any quarterly cash distribution until the holders of our common units have received a quarterly cash distribution of $0.59 per common unit.

The following table sets forth our distributions, as approved by the board of directors for each period in the years ended December 31, 2007, 2006 and 2005.

Distribution Declaration Date	Distribution Payment Date	Record Date	Distribution per Unit	Cash available for distribution	Amount of Distribution of i-units to i-unit Holders(1)	Amount of Distribution of Class C units to Class C unit Holders(2)	Retained from General Partner(3)	Distribution of Cash
				(in millions, except per unit amounts)				
2007								
October 29	November 14	November 6	$ 0.950	$ 96.0	$ 12.7	$ 16.8	$ 0.6	$ 65.9
July 27	August 14	August 6	0.925	92.6	12.1	16.2	0.6	63.7
April 26	May 15	May 7	0.925	86.6	11.9	15.9	0.6	58.2
January 26	February 14	February 6	0.925	80.0	11.7	10.2	0.5	57.6
				$ 355.2	$ 48.4	$ 59.1	$ 2.3	$ 245.4
2006								
October 27	November 14	November 6	$ 0.925	$ 79.6	$ 11.5	$ 10.1	$ 0.4	$ 57.6
July 28	August 14	August 4	0.925	68.1	11.3	—	0.2	56.6
April 27	May 15	May 5	0.925	67.8	11.0	—	0.2	56.6
January 30	February 14	February 7	0.925	67.6	10.8	—	0.2	56.6
				$ 283.1	$ 44.6	$ 10.1	$ 1.0	$ 227.4
2005								
October 26	November 14	November 3	$ 0.925	$ 64.1	$ 10.6	$ —	$ 0.2	$ 53.3
July 28	August 12	August 5	0.925	64.0	10.5	—	0.2	53.3
April 25	May 13	May 4	0.925	63.8	10.3	—	0.2	53.3
January 24	February 14	February 3	0.925	61.0	10.1	—	0.2	50.7
				$ 252.9	$ 41.5	$ —	$ 0.8	$ 210.6

(1) We issued 889,938, 969,200 and 802,539 i-units to Enbridge Energy Management, L.L.C., the sole owner of our i-units, during 2007, 2006 and 2005, respectively, in lieu of cash distributions.

(2) We issued 1,072,423 and 200,587 additional Class C units to our Class C unitholders in lieu of cash distributions during 2007 and 2006, including 385,032 and 100,293 to our general partner, respectively.

(3) We retained an amount equal to 2 percent of the i-unit and Class C unit distribution from the General Partner to maintain its 2 percent general partner interest in us.

11. RELATED PARTY TRANSACTIONS

Administrative and Workforce Related Services

Enbridge and its affiliates provide management and administrative, operations and workforce related services to us. Employees of Enbridge and its affiliates are assigned to work for one or more affiliates of Enbridge, including us. Where directly attributable, the costs of all compensation, benefits expenses and employer expenses for these employees are charged directly by Enbridge to the appropriate affiliate. Enbridge does not record any profit or margin for the services charged to us.

The portion of direct workforce costs associated with the management and administrative services provided at our Houston office and the operating and administrative services provided to support our facilities across the United States, are charged to us by Enbridge and its affiliates.

Certain of the operating activities associated with our Liquids segment are provided by Enbridge Pipelines Inc. ("Enbridge Pipelines"), a subsidiary of Enbridge, as the majority of these pipeline systems form one contiguous system with the Enbridge system in Canada. These services include control center operations, facilities management, shipper services, pipeline integrity management and other related activities. The costs to provide these services are allocated to us from Enbridge Pipelines, based on an appropriate allocation methodology consistent with Enbridge's corporate cost allocation policy, including estimated time spent and miles of pipe. We also receive costs associated with control center services for some of the natural gas assets from another affiliate of Enbridge.

Enbridge also allocates management and administrative costs to us pursuant to our partnership agreement and related services agreements. These costs are allocated to us based on an allocation methodology consistent with Enbridge's corporate cost allocation policy, including estimated time spent, number of full-time equivalent employees and capital employed.

During 2007, 2006 and 2005, we incurred the following costs related to these services, which are included in operating and administrative expenses.

	Year ended December 31,		
	2007	2006	2005
		(in millions)	
Direct workforce costs	$ 181.6	$ 152.1	$ 111.3
Allocated Liquids and Natural Gas operating costs	20.1	17.3	15.3
Allocated management and administrative costs, including insurance	28.9	27.4	20.1
	$ 230.6	$ 196.8	$ 146.7

Enbridge and its affiliates allocated direct workforce costs to us related to our construction projects of $18.1 million, $11.8 million and $5.7 million during 2007, 2006 and 2005, respectively, that we recorded as additions to property, plant and equipment on our consolidated statements of financial position.

Affiliate Revenues and Purchases

We purchase natural gas from third-parties, which subsequently generates operating revenues from sales to Enbridge and its affiliates. These transactions are entered into at the market price on the date of sale. We also record operating revenues in our Liquids segment for storage, transportation and terminaling services we provide to affiliates. Included in our results for the twelve months ending December 31, 2007, 2006 and 2005, are operating revenues of $95.2 million, $42.8 million, and $43.6 million, respectively, related to these transactions.

In 2007, we entered into an agreement with Enbridge Pipelines Inc., a wholly-owned subsidiary of Enbridge, to install and operate certain sampling and related facilities for the purpose of improving the quality of crude oil and the transportation services on our Lakehead system, which directly increases the transportation services revenue of Enbridge Pipelines Inc. As compensation for installing and operating these transportation facilities, Enbridge Pipelines Inc. makes annual payments to us on a cost of service basis. The income we accrued for providing these transportation services in 2007 was approximately $0.6 million.

We also purchase natural gas from Enbridge and its affiliates for sale to third-parties at market prices on the date of purchase. Included in our results for the twelve months ending December 31, 2007, 2006 and 2005, are cost of natural gas expenses of $6.2 million, $11.5 million and $4.5 million, respectively, relating to these purchases.

Notes Payable to Affiliates

Hungary Note Payable

As of December 31, 2007 and 2006, we had $130.0 million and $136.2 million, respectively, in amounts outstanding under notes payable to Enbridge Hungary Ltd., an affiliate of our general partner, which we refer to as the Hungary Note. In December 2007, we repaid $145.0 million of the original Hungary Note, including $8.8 million of accrued interest, with proceeds we received from entering into a new Hungary

Note agreement with substantially the same terms and approximately $15 million from our existing cash. The new Hungary Note bears interest at a fixed rate of 8.4% per annum that is payable semi-annually in June and December of each year through its maturity in December 2017. Similar to the old Hungary Note, the new note allows us the option of paying accrued and unpaid interest in the form of additional indebtedness by increasing the principal balance of the note for the amounts due. Consistent with the original Hungary Note, the new Hungary Note has cross-default provisions that are triggered by events of default under our First Mortgage Notes or defaults under our Credit Facility. The new Hungary Note is subordinate to our Credit Facility and other senior indebtedness, and ranks equally with current and future Junior Notes. We entered into the original Hungary Note agreement in connection with our acquisition of the Midcoast system in October 2002. For the year ended December 31, 2006, we converted interest payable in the amount of $4.4 million into debt by increasing the principal balance of the original Hungary Note.

EUS Credit Agreement

In December 2007, we entered into an unsecured revolving credit agreement (the "EUS Credit Agreement") with Enbridge (U.S.) Inc., a wholly-owned subsidiary of Enbridge. Enbridge is the indirect owner of Enbridge Energy Company, Inc., our general partner. The EUS Credit Agreement provides for a maximum principal amount of credit available to us at any one time of $500 million for a three-year term that matures in December 2010. The EUS Credit Agreement also includes financial covenants that are consistent with those in our Second Amended and Restated Credit Agreement as discussed above. Amounts borrowed under the EUS Credit Agreement bear interest at rates that are consistent with the interest rates set forth in our Second Amended and Restated Credit Agreement. At December 31, 2007, we had no balances outstanding under the EUS Credit Agreement and the full amount remains available for our use.

General Partner Equity Transactions

Our general partner owns an effective two percent general partner ownership interest in us. Pursuant to our partnership agreement we paid cash distributions to our general partner of $34.9 million, $28.1 million, and $25.3 million for the years ended December 31, 2007, 2006 and 2005, respectively. The cash distributions we make to our general partner exclude an amount equal to two percent of the i-unit and Class C unit distributions, which we retain from the General Partner to maintain its two percent ownership interest in us.

As of December 31, 2007 and 2006, the General Partner also owned 3,912,750 Class B common units, representing a 4.2 and 4.9 percent limited partner interest in us for the respective years. We paid the General Partner cash distributions of $14.5 million for the years ended December 31, 2007, 2006 and 2005, related to its ownership of Class B common units.

At December 31, 2007 and 2006, our general partner owned 5,920,108 and 5,535,076 of our Class C units. We distributed 385,032 and 100,293 additional Class C units to our general partner during the years ended December 31, 2007 and 2006, respectively, in lieu of making cash distributions. The Class C units owned by our general partner at December 31, 2007 and 2006 represent an approximately 6.4 percent and 7.0 percent limited partner interest in us. Refer to Note 10 for additional information regarding the Class C units.

In May 2007, we issued and sold 5.3 million of our Class A common units to the public for $58.00 per Class A common unit. As part of this transaction our general partner contributed approximately $6.1 million to us to maintain its two percent general partner interest.

In April 2007, we issued and sold 5.9 million Class C units at a price of $53.11 per Class C unit to institutional investors. As part of this transaction our general partner contributed approximately $6.4 million to us to maintain its two percent general partner interest.

In August 2006, we sold approximately 5.4 million of our Class C units to our general partner for $250 million, or $46.00 per unit and 5.4 million Class C units to institutional investors for $250 million. As part of this transaction our general partner contributed approximately $10.2 million to maintain its two percent general partner interest.

Conflicts of Interest

Enbridge Management makes all decisions relating to the management and control of our business through a delegation of control agreement with the General Partner and us. The General Partner owns the voting shares of Enbridge Management and elects all of Enbridge Management's directors. Enbridge, through its wholly-owned subsidiary, Enbridge Pipelines, owns all the common stock of the General Partner. Some of the General Partner's directors and officers are also directors and officers of Enbridge and Enbridge Management and have fiduciary duties to manage the business of Enbridge and Enbridge Management in a manner that may not be in the best interests of our unitholders. Certain conflicts of interest could arise as a result of the relationships among Enbridge Management, the General Partner, Enbridge and us. Our partnership agreement and the delegation of control agreement contain provisions that allow Enbridge Management to take into account the interest of all parties in addition to those of our unitholders in resolving conflicts of interest, thereby limiting its fiduciary duties to our unitholders, as well as provisions that may restrict the remedies available to our unitholders for actions taken that might, without such limitations, constitute breaches of fiduciary duty.

Enbridge Management

Pursuant to the delegation of control agreement between Enbridge Management, our General Partner and us, and our partnership agreement, we pay all expenses relating to Enbridge Management. This includes Texas franchise taxes and any other similar capital-based foreign, state and local taxes not otherwise paid or reimbursed pursuant to a tax indemnification agreement between Enbridge and Enbridge Management on behalf of Enbridge Management.

12. COMMITMENTS AND CONTINGENCIES

Environmental Liabilities

We are subject to federal and state laws and regulations relating to the protection of the environment. Environmental risk is inherent to liquid hydrocarbon and natural gas pipeline operations and we could, at times, be subject to environmental cleanup and enforcement actions. We manage this environmental risk through appropriate environmental policies and practices to minimize any impact our operations may have on the environment. To the extent that we are unable to recover environmental liabilities associated with the Lakehead system assets through insurance, the General Partner has agreed to indemnify us from and against any costs relating to environmental liabilities associated with the Lakehead system assets prior to the transfer to us in 1991. This excludes any liabilities resulting from a change in laws after such transfer. We continue to voluntarily investigate past leak sites on our systems for the purpose of assessing whether any remediation is required in light of current regulations, and to date, no material environmental risks have been identified.

In November 2007, an unexpected release and fire on line 3 of our Lakehead system occurred during planned maintenance near our Clearbrook, Minnesota terminal. We immediately shut down all pipelines in the vicinity and dispatched emergency response crews to oversee containment, cleanup and repair of the pipeline at an estimated economic cost of $2.6 million. Lines 1, 2 and 4 were restarted the following day after inspections revealed these lines had not been damaged. The volume of oil released was approximately 325 barrels, which was largely contained in the trench that had been excavated to facilitate the planned maintenance. We completed excavation and repairs and returned the line to service within 5 days. We continue to work with federal and state environmental and pipeline safety regulators to investigate the cause of the incident. We have the potential of incurring additional costs in connection with this incident, including expenditures necessary to remediate any operating condition that is determined to have caused this incident.

As of December 31, 2007 and 2006, we have recorded $3.4 million and $4.1 million in current liabilities and $2.8 million and $3.3 million, respectively, in long-term liabilities primarily to address remediation of asbestos containing materials, management of hazardous waste material disposal, and outstanding air quality measures for certain of our liquids and natural gas assets.

Oil and Gas in Custody

Our Liquids assets transport crude oil and NGLs owned by our customers for a fee. The volume of liquid hydrocarbons in our pipeline systems at any one time varies from approximately 22 to 40 million barrels, virtually all of which is owned by our customers. Under the terms of our tariffs, losses of crude oil from identifiable incidents not resulting from our direct negligence may be apportioned among our customers. In addition, we maintain adequate property insurance coverage with respect to crude oil and NGLs in our custody.

Approximately 50% of the natural gas volumes on our natural gas assets are transported for customers on a contractual basis. We purchase the remaining 50% and sell to third-parties downstream of the purchase point. At any point in time, the value of our customers' natural gas in the custody of our natural gas systems is not material to us.

Right-of-Way

As part of our pipeline construction process, we must obtain certain right-of-way agreements from landowners whose property the pipeline will cross. Right-of-way agreements that we buy are capitalized as part of Property, plant and equipment. Right-of-way agreements that are leased from a third-party are expensed. We recorded expenses of $1.6 million, $2.1 million, and $1.9 million for the leased right-of-way agreements for the years ended December 31, 2007, 2006, and 2005, respectively.

Legal Proceedings

We are a participant in various legal proceedings arising in the ordinary course of business. Some of these proceedings are covered, in whole or in part, by insurance. We believe that the outcome of all these proceedings will not, individually or in the aggregate, have a material adverse effect on our financial condition.

Future Minimum Commitments

As of December 31, 2007, our future minimum commitments that have remaining non-cancelable terms in excess of one year are as follows:

Future Minimum Commitments	2008	2009	2010	2011	2012	Thereafter	Total
				(in millions)			
Purchase commitments[1]	$ 305.4	$ —	$ —	$ —	$ —	$ —	$ 305.4
Power commitments[2]	2.9	0.2	0.2	—	—	—	3.3
Other operating leases	11.9	8.9	2.7	0.4	—	0.1	24.0
Right-of-way[3]	1.7	1.7	1.7	1.7	1.7	41.0	49.5
Product purchase obligations[4]	55.7	38.5	34.5	32.7	31.0	84.3	276.7
Service contract obligations[5]	36.0	28.8	25.6	18.6	7.3	0.5	116.8
Total	$ 413.6	$ 78.1	$ 64.7	$ 53.4	$ 40.0	$ 125.9	$ 775.7

(1) Represents commitments to purchase materials, primarily pipe from third-party suppliers in connection with our expansion projects.

(2) Represents commitments to purchase power in connection with our Liquids segment.

(3) Right-of-way payments are estimated to be approximately $1.7 million per year for the remaining life of all pipeline systems, which has been assumed to be 25 years for purposes of calculating the amount of future minimum commitments beyond 2012.

(4) We have long-term product purchase obligations with several third-party suppliers to acquire natural gas and NGLs at prices approximating market at the time of delivery.

(5) The service contract obligations represent the minimum payment amounts for firm transportation and storage capacity we have reserved on third-party pipelines and storage facilities.

13. FINANCIAL INSTRUMENTS

Fair Value of Debt Obligations

The table below presents the carrying amount and approximate fair values of our debt obligations. The carrying amounts of our commercial paper obligations approximate their fair values at December 31, 2007, due to the short-term nature of these obligations. The fair values of the First Mortgage Notes and Senior notes have been determined based on quotations of indicative pricing for which we could issue the same or similar securities quoted market prices for the same or similar issues.

	December 31, 2007		December 31, 2006	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Commercial paper	$ 268.5	$ 268.5	$ 443.7	$ 443.7
Credit Facility	400.0	400.0	—	—
9.150% First Mortgage Notes	124.0	135.1	155.0	169.5
5.358% Senior unsecured zero coupon notes due 2022	203.6	210.7	—	—
4.000% Senior notes due 2009	200.0	198.5	200.0	194.2
7.900% Senior notes due 2012	99.9	110.2	99.9	110.5
4.750% Senior notes due 2013	199.8	192.0	199.8	188.6
5.350% Senior notes due 2014	199.9	194.3	199.9	193.0
5.875% Senior notes due 2016	299.7	293.7	299.7	297.4
7.000% Senior notes due 2018	99.9	105.3	99.8	107.9
7.125% Senior notes due 2028	99.8	104.3	99.8	108.9
5.950% Senior notes due 2033	199.7	176.9	199.7	186.2
6.300% Senior notes due 2034	99.8	92.1	99.8	97.1
8.050% Junior subordinated notes due 2067	399.3	385.9	—	—

Fair Value of Derivative Financial Instruments

The fair values of our derivative financial instruments are determined based on available market information, valuation and modeling techniques. These modeling techniques require us to make estimates of future prices, price correlation, market volatility and liquidity. The estimates also reflect factors for time value of money and the volatility of prices underlying the contracts, the potential impact of liquidating positions in an orderly manner over a reasonable period of time under present market conditions, modeling risk, credit risk of counterparties and operational risk.

Interest Rate Derivatives

We enter into interest rate swaps, collars and derivative financial instruments with similar characteristics to manage the effect of future interest rate movements on our interest costs. The following table provides information about our current interest rate derivatives by transaction type for the specified periods.

	Notional Principal	Partnership Pays	Partnership Receives	Maturity Date	Fair Value at December 31, 2007	Fair Value at December 31, 2006
					(dollars in millions)	
Interest Rate Swaps						
Floating to Fixed:						
	$ 50.0	4.715%	LIBOR [2]	January 22, 2007	$ —	$ 0.1
	$ 50.0	4.738%	LIBOR	January 24, 2007	—	0.1
	$ 50.0	4.740%	LIBOR	February 3, 2007	—	0.1
	$ 50.0	4.750%	LIBOR	February 8, 2007	—	0.1
	$ 50.0	5.158%	LIBOR	April 3, 2007	—	0.1
	$ 50.0	5.163%	LIBOR	April 10, 2007	—	—
	$ 50.0	5.165%	LIBOR	April 17, 2007	—	—
	$ 50.0	5.175%	LIBOR	April 25, 2007	—	—
	$ 50.0	4.6175%	LIBOR	January 15, 2009	(0.3)	—
	$ 50.0	4.6130%	LIBOR	January 29, 2009	(0.3)	—
	$ 50.0	4.6525%	LIBOR	February 13, 2009	(0.4)	—
	$ 50.0	4.5875%	LIBOR	February 20, 2009	(0.4)	—
	$ 50.0	4.370%	LIBOR-21bps	June 1, 2013	(0.7)	1.5
	$ 50.0	4.3425%	LIBOR-21bps	June 1, 2013	(0.6)	1.6
	$ 25.0	4.310%	LIBOR-25bps	June 1, 2013	(0.3)	0.7
Fixed to Floating:						
	$ 50.0	LIBOR-21bps [1]	4.750%	June 1, 2013	1.6	(0.5)
	$ 50.0	LIBOR-21bps	4.750%	June 1, 2013	1.6	(0.5)
	$ 25.0	LIBOR-25bps	4.750%	June 1, 2013	0.9	(0.3)
Treasury Locks:						
	$ 100.0	4.697%	30Yr UST [3]	December 17, 2007	—	1.2
	$ 100.0	4.668%	30Yr UST	December 17, 2007	—	1.6
	$ 100.0	4.750%	30Yr UST	June 30, 2008	(4.4)	—
	$ 100.0	4.714%	30Yr UST	June 30, 2008	(3.9)	—
Interest Rate Collars:						
Calls	$ 50.0	5.500%	LIBOR	June 13, 2008	—	0.1
Puts	$ 50.0	4.199%	LIBOR	June 13, 2008	—	—
Calls	$ 50.0	5.500%	LIBOR	June 25, 2008	—	—
Puts	$ 50.0	4.149%	LIBOR	June 25, 2008	—	—

(1) A bps refers to a basis point. One basis point is equivalent to 1/100th of 1 percent.

(2) LIBOR refers to the three-month U.S. London Interbank Offered Rate.

(3) UST refers to United States Treasury notes.

Our treasury locks and a portion of our interest rate collars maturing in 2008 qualify for hedge accounting treatment pursuant to the requirements of SFAS No. 133 and have been designated as cash flow hedges of future interest payments on the first $200 million of an anticipated debt issuance and interest payments on $50 million of our variable rate indebtedness, respectively. As such, the fair value of these derivative financial instruments is recorded as assets or liabilities on our consolidated statements of financial position with the changes in fair value recorded as corresponding increases or decreases in Accumulated Other Comprehensive Income, or AOCI. Our floating to fixed rate interest rate swaps and a portion of our interest rate collars maturing in 2008 and 2009 hedging $250 million of our variable rate indebtedness did not qualify for hedge accounting treatment as set forth in SFAS No. 133 at December 31, 2007. As such, changes in the fair value of these derivative financial instruments are recorded in earnings as an increase or decrease in interest expense. A portion of these transactions have subsequently been re-designated as cash flow hedges of forecast floating rate indebtedness.

The floating to fixed rate and fixed to floating rate interest rate swaps maturing in 2013 have not been designated as cash flow or fair value hedges under SFAS No. 133 and, as a result, changes in the fair value of these derivative financial instruments are recorded in earnings as an increase or decrease in interest expense.

Commodity Price Derivatives

The following table provides summarized information about the fair values of our outstanding commodity derivative financial instruments at December 31, 2007 and 2006:

	December 31, 2007					December 31, 2006	
		Wtd Avg Price		Fair Value[3]		Fair Value[3]	
	Notional	Receive	Pay	Asset	Liability	Asset	Liability
Swaps							
Natural gas[1]							
Receive variable/ pay fixed	53,477,203	$ 7.43	$ 7.31	$ 21.6	$ (16.1)	$ 25.6	$ (94.2)
Receive fixed/ pay variable	67,237,786	5.59	8.00	11.5	(160.5)	84.3	(160.7)
Receive variable/ pay variable	208,270,399	7.87	7.84	11.5	(6.0)	7.9	(4.8)
NGL[2]							
Receive variable/ pay fixed	—	—	—	—	—	—	(0.5)
Receive fixed/ pay variable	10,163,878	42.19	58.68	—	(160.6)	18.3	(34.4)
Crude[2]							
Receive fixed/ pay variable	1,411,221	62.27	88.36	—	(34.6)	0.2	(18.5)
Options—calls							
Natural gas[1]	1,461,000	4.31	8.36	—	(5.6)	—	(5.4)
Options—puts							
Natural gas[1]	1,401,000	8.41	3.40	—	—	1.0	—
NGL[2]	763,403	61.42	43.54	0.7	—	—	—
Totals[4]				$ 45.3	$ (383.4)	$ 137.3	$ (318.5)

(1) Notional amounts for natural gas are recorded in millions of British thermal units ("MMBtu").

(2) Notional amounts for NGL and Crude are recorded in Barrels ("Bbl").

(3) Fair values of derivatives are presented in millions of dollars.

(4) We record the fair value of our derivative financial instruments in the balance sheet as current and long-term assets or liabilities on a net basis by counterparty.

14. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES

Our net income and cash flows are subject to volatility stemming from changes in interest rates on our variable rate debt obligations and fluctuations in commodity prices of natural gas, NGLs, condensate and fractionation margins (the relative difference between the price we receive from NGL sales and the corresponding cost of natural gas purchases). Our interest rate risk exposure does not exist within any of our segments, but exists at the corporate level where our variable rate debt obligations are issued. Our exposure to commodity price risk exists within our Natural Gas and Marketing segments. We use derivative financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to manage the risks associated with market fluctuations in commodity prices and interest rates, as well as reduce volatility to our cash flows. Based on our risk management policies, all of our derivative financial instruments are employed in connection with an underlying asset, liability and/or forecasted transaction and are not entered into with the objective of speculating on interest rates or commodity prices.

Accounting Treatment

We record all derivative financial instruments in our consolidated financial statements at fair market value which we adjust each period for changes in the fair market value ("mark-to-market"). The fair market value of these derivative financial instruments reflects the estimated amounts that we would pay or receive, other than in a forced or liquidation sale, to terminate or close the contracts at the reporting date, taking into account the current unrealized losses or gains on open contracts. We use actively traded external market quotes and indices to value substantially all of the derivative financial instruments we utilize.

Under the guidance of SFAS No. 133, if a derivative financial instrument does not qualify as a hedge, or is not designated as a hedge, the derivative is adjusted to its fair market value, or marked-to-market, each period with the increases and decreases in fair value recorded in our consolidated statements of income as increases and decreases in Cost of natural gas for our commodity-based derivatives and Interest expense for our interest rate derivatives. Cash flow is only impacted to the extent the actual derivative contract is settled by making or receiving a payment to or from the counterparty or by making or receiving a payment for entering into a contract that exactly offsets the original derivative contract. Typically, we settle our derivative contracts when the physical transaction that underlies the derivative financial instrument occurs.

If a derivative financial instrument qualifies and is designated as a cash flow hedge, a hedge of a forecasted transaction or future cash flows, any unrealized mark-to-market gain or loss is deferred in Accumulated other comprehensive income ("AOCI"), a component of Partners' Capital, until the underlying hedged transaction occurs. To the extent that the hedge instrument is effective in offsetting the transaction being hedged, there is no impact to the income statement. At inception and on a quarterly basis, we formally assess whether the hedge contract is highly effective in offsetting changes in cash flows of hedged items. Any ineffective portion of a cash flow hedge's change in fair market value is recognized each period in earnings. Realized gains and losses on derivative financial instruments that are designated as hedges and qualify for hedge accounting are included in Cost of natural gas for commodity hedges and Interest expense for interest rate hedges in the period the hedged transaction occurs. Gains and losses deferred in AOCI related to cash flow hedges for which hedge accounting has been discontinued, remain in AOCI until the underlying physical transaction occurs unless it is probable that the forecasted transaction will not occur by the end of the originally specified time period, or within an additional two-month period of time thereafter. Generally, our preference is for our derivative financial instruments to receive hedge accounting treatment whenever possible, to mitigate the non-cash earnings volatility that arises from recording the changes in fair value of our derivative financial instruments through earnings. To qualify for cash flow hedge accounting as set forth in SFAS No. 133, very specific requirements must be met in terms of hedge structure, hedge objective and hedge documentation.

If a derivative financial instrument is designated and qualifies as a hedge of the change in fair market value of an underlying asset or liability, the gain or loss resulting from the change in fair market value of the derivative financial instrument is recorded in earnings adjusted by the gain or loss resulting from the change in fair market value of the underlying asset or liability. Any ineffective portion of a fair value hedge's change in fair market value will be recorded in earnings as the amount that is not offset by the gain or loss on the change in fair market value of the underlying asset or liability. We include the gains and losses associated with derivative financial instruments designated and qualifying as fair value hedges of our debt obligations in Interest expense on our consolidated statements of income. Similar to derivative financial instruments designated as cash flow hedges, to qualify as a fair value hedge very specific requirements must be met in terms of hedge structure, hedge objective and hedge documentation.

Non-Qualified Hedges

Many of our derivative financial instruments qualify for hedge accounting treatment under the specific requirements of SFAS No. 133. However, we have four primary transaction types associated with our commodity derivative financial instruments where the hedge structure does not meet the requirements to apply hedge accounting. As a result, these derivative financial instruments do not qualify for hedge accounting under SFAS No. 133 and are referred to as "non-qualified." These non-qualified derivative financial instruments are marked-to-market each period with the change in fair value, representing unrealized gains and losses, included in cost of natural gas in our consolidated statements of income. These mark-to-market adjustments produce a degree of earnings volatility that can often be significant from period to period, but have no cash flow impact relative to changes in market prices. The cash flow impact occurs when the underlying physical transaction takes place in the future and the associated financial instrument contract settlement is made.

The four primary transaction types that do not qualify for hedge accounting are as follows:

1. **Transportation—**In our Marketing segment, when we transport natural gas from one location to another the pricing index used for natural gas sales is usually different from the pricing index used for natural gas purchases, which exposes us to market price risk relative to changes in those two indices. By entering into a basis swap, where we exchange one pricing index for another, we can effectively lock in the margin, representing the difference between the sales price and the purchase price, on the combined natural gas purchase and natural gas sale, removing any market price risk on the physical transactions. Although this represents a sound economic hedging strategy, the derivative financial instruments (i.e., the basis swaps) we use to manage the commodity price risk associated with these transportation contracts do not qualify for hedge accounting under SFAS No. 133, since only the future margin has been fixed and not the future cash flow. As a result, the changes in fair value of these derivative financial instruments are recorded in earnings.

2. **Storage—**In our Marketing segment, we use derivative financial instruments (i.e., natural gas swaps) to hedge the relative difference between the injection price paid to purchase and store natural gas and the withdrawal price at which the natural gas is sold from storage. The intent of these derivative financial instruments is to lock in the margin, representing the difference between the price paid for the natural gas injected and the price received upon withdrawal of the gas from storage in a future period. We do not pursue cash flow hedge accounting treatment for these storage transactions since the underlying forecasted injection or withdrawal of natural gas may not occur in the period as originally forecast. This can occur because we have the flexibility to make changes in the underlying injection or withdrawal schedule, given changes in market conditions. In addition, since the physical natural gas is recorded at the lower of cost or market, timing differences can result when the derivative financial instrument is settled in a period that is different from the period the physical natural gas is sold from storage. As a result, derivative financial instruments associated with our natural gas storage activities can create volatility in our earnings.

3. **Natural Gas Collars—**In our Natural Gas segment, we had previously entered into natural gas collars to hedge the sales price of natural gas. The natural gas collars were based on a NYMEX price, while the physical gas sales were based on a different index. To better align the index of the natural gas collars with the index of the underlying sales, we de-designated the original cash flow hedging relationship with the intent of contemporaneously re-designating the natural gas collars

as hedges of forecasted physical natural gas sales with a NYMEX pricing index. However, because the fair value of these derivative instruments was a liability to us at re-designation, they are considered net written options under SFAS No. 133 and do not qualify for hedge accounting. These derivatives are being marked-to-market, with the changes in fair value from the date of de-designation recorded to earnings each period. As a result, our operating income will be subject to greater volatility due to movements in the prices of natural gas until the underlying long-term transactions are settled.

4. **Optional Natural Gas Processing Volumes—**In our Natural Gas segment we use derivative financial instruments to hedge the volumes of NGLs produced from our natural gas processing facilities. Our natural gas contracts allow us the option of processing natural gas when it is economical, and ceasing to do so when processing becomes uneconomic. We have entered into derivative financial instruments to fix the sales price of a portion of the NGLs that we produce at our discretion and to fix the associated purchases of natural gas required for processing. We will designate derivative financial instruments associated with NGLs we produce at our discretion as cash flow hedges when the processing of natural gas is probable of occurrence. However, we are precluded from designating the derivative financial instruments entered to manage the respective commodity price risk when we are unable to accurately forecast the NGLs to be processed at our discretion. As a result, our operating income will be subject to increased volatility due to fluctuations in NGL prices until the underlying transactions are settled or offset.

In each of the instances described above, the underlying physical purchase, storage and sale of natural gas and NGLs are accounted for on a historical cost or market basis rather than on the mark-to-market basis we utilize for the derivative financial instruments employed to mitigate the commodity price risk associated with our storage and transportation assets. This difference in accounting (i.e., the derivative financial instruments are recorded at fair market value while the physical transactions are recorded at historical cost) can and has resulted in volatility in our reported net income, even though the economic margin is essentially unchanged from the date the transactions were consummated.

We routinely enter into interest rate swaps to fix the interest rates associated with our variable rate debt, including commercial paper and bank borrowings. In August 2007, we entered into forward-starting interest rate swaps that we designated as cash flow hedges of variable rate debt to begin in October 2007 and November 2007. The specific floating rate borrowings did not take place as initially forecast, thereby causing the interest rates swaps to no longer qualify as cash flow hedges. As a result, we recorded a charge to interest expense of $1.4 million, representing the fair market value of the interest rate swaps at December 31, 2007. A portion of these transactions have subsequently been re-designated as cash flow hedges of forecast floating rate indebtedness.

Discontinuance of Hedge Accounting

In 2005, we discontinued application of hedge accounting in connection with some of our derivative financial instruments designated as hedges of forecasted sales and purchases of natural gas. We discontinued application of hedge accounting when we determined it was no longer probable that the originally forecasted purchases and sales of natural gas would occur by the end of the originally specified time period, or within an additional two-month period of time thereafter. As discussed above, this can occur because we have the flexibility to make changes to the underlying delivery locations for our transportation assets and to the underlying injection or withdrawal schedule for our storage assets, given changes in market conditions. One of the key criteria to achieve hedge accounting under SFAS No. 133 is that the forecasted transaction be probable of occurring as originally set forth in the hedge documentation. As a result, in 2005, we recognized previously deferred unrealized losses in our Marketing segment of approximately $9.0 million from the discontinuance of hedge accounting. In doing so, we reclassified the $9.0 million to cost of natural gas on our consolidated statements of income from AOCI. Going forward, the derivative financial instruments for which hedge accounting has been discontinued are considered to be non-qualified under SFAS No. 133, and must be marked-to-market each period, with the increases and decreases in fair value recorded as increases and decreases in earnings. Also included in the loss from discontinuance are approximately $2.1 million of net mark-to-market losses that relate to hedge positions that were closed out in 2005.

The following table presents the unrealized gains and losses associated with changes in the fair value of our derivatives, which are recorded as an element of cost of natural gas and interest expense in our consolidated statements of income and disclosed as a reconciling item on our consolidated statements of cash flows:

Derivative fair value gains (losses)	December 31, 2007	December 31, 2006	December 31, 2005
		(in millions)	
Natural Gas segment			
Hedge ineffectiveness	$ —	$ (1.9)	$ (2.5)
Non-qualified hedges	(59.0)	1.8	(5.6)
Marketing			
Non-qualified hedges	(3.8)	64.5	(41.3)
Discontinued hedges	—	—	(9.0)
Commodity derivative fair value gains (losses)	(62.8)	64.4	(58.4)
Corporate			
Non-qualified interest rate hedges	(1.4)	—	—
Derivative fair value gains (losses)	$ (64.2)	$ 64.4	$ (58.4)

De-designation and Settlement of Derivatives

In connection with the sale of assets in December 2005, as discussed in Note 3 to these consolidated financial statements, we settled for cash of approximately $16.3 million, natural gas collars representing derivative financial instruments on sales of 2,000 MMBtu/d of natural gas through 2011. We had previously recorded unrealized losses associated with the natural gas collars that were realized upon settlement. Additionally, we de-designated derivative financial instruments that qualified for and were designated as cash flow hedges of forecasted sales of 273 Bpd of NGLs through 2007 and contemporaneously closed out the position by entering into an offsetting derivative financial instrument, at market, on forecasted purchases of 273 Bpd of NGLs through 2007.

Derivative Positions

Our derivative financial instruments are included at their fair values in the consolidated statements of financial position as follows:

	December 31, 2007	December 31, 2006
	(in millions)	
Other current assets	$ 6.5	$ 7.2
Other assets, net	6.4	11.0
Accounts payable and other	(165.5)	(57.2)
Other long-term liabilities	(192.9)	(136.4)
	$ (345.5)	$ (175.4)

The increase in our obligation associated with derivative activities is primarily due to the increase in current and forward natural gas and NGL prices from December 31, 2006 to December 31, 2007. Our portfolio of derivative financial instruments is largely comprised of long-term fixed price natural gas and NGL sales and purchase agreements.

We record the change in fair value of our highly effective cash flow hedges in AOCI until the derivative financial instruments are settled, at which time they are reclassified to earnings. We regularly enter into treasury locks to hedge the interest on anticipated issuances of indebtedness. The settlement of a treasury lock can result in the retention of unrecognized gains or losses in AOCI that are amortized to interest expense over the life of the related debt issuance. In connection with our 2007 issuance and sale of $400 million in principal amount of our Junior Notes, we paid $0.9 million to settle treasury locks we entered to hedge the first five years of interest payments on a portion of this obligation. The $0.9 million is being amortized from AOCI to interest expense over the five year period for which the derivative instrument was established to hedge of interest payments on the junior notes. In December 2006, we paid $10.2 million to settle treasury locks we entered to hedge a portion of the interest payments associated with our issuance of $300 million in principal amount of our senior notes. The $10.2 million is being amortized from AOCI to interest expense over the 10-year life of the senior notes.

Also included in AOCI are unrecognized losses of approximately $2.0 million associated with derivative financial instruments that qualified for and were classified as cash flow hedges of forecasted commodity transactions that were subsequently de-designated. These unrealized losses are reclassified to earnings over the periods during which the originally hedged forecasted transactions affect earnings. For the years ended December 31, 2007, 2006 and 2005, we reclassified unrealized losses of $94.8 million, $78.3 million and $33.8 million, respectively, from AOCI to cost of natural gas on our consolidated statements of income for the fair value of derivative financial instruments that were settled. We estimate that approximately $113 million of AOCI representing unrealized net losses on cash flow hedging activities at December 31, 2007, will be reclassified to earnings during the next twelve months.

We do not require collateral or other security from the counterparties to our derivative financial instruments, all of which were rated "BBB+" or better by the major credit rating agencies.

15. INCOME TAXES

We are not a taxable entity for U.S. federal income tax purposes, or for the majority of states that impose an income tax. These taxes on our net income are generally borne by our unitholders through the allocation of taxable income. Beginning in 2006, two states enacted substantial changes to their tax structures to impose taxes that are based upon many but not all items included in net income. We report these taxes as income taxes under the provisions of Statement of Financial Accounting Standards No. 109, *Accounting for Income Taxes* ("SFAS No. 109").

Our income tax expense is $5.1 million for the year ended December 31, 2007, which we computed by applying a 0.57% state income tax rate to modified gross revenue. Our income tax expense represents a 2.0% effective rate as applied to pretax book income. At December 31, 2007 we have included a current income tax payable of $4.9 million in property and other taxes payable. In addition, we have included a deferred income tax asset of $0.6 million in other assets, net on our consolidated statement of financial position to reflect the tax associated with the difference between the net basis in assets and liabilities for financial and state tax reporting.

We recognize deferred income tax assets and liabilities for temporary differences between the relevant basis of our assets and liabilities for financial reporting and tax purposes. The impact of changes in tax legislation on deferred income tax liabilities and assets is recorded in the period of enactment. The tax effects of significant temporary differences representing deferred tax assets and liabilities are as follows:

Net book basis of assets in excess of tax basis	$	(1.3)
Net book losses on derivatives not recognized for tax purposes		1.9
Net deferred tax asset	$	0.6

Accounting for Uncertainty in Income Taxes

In July 2006, the Financial Accounting Standards Board ("FASB") issued Interpretation No. 48, *Accounting for Uncertainty in Income Taxes-an Interpretation of FASB Statement 109,* or FIN 48. This Interpretation clarifies the accounting for uncertainty in income taxes recognized in a company's financial statements in accordance with FASB Statement No. 109, *Accounting for Income Taxes*. We implemented FIN 48 during the first quarter of 2007. Our adoption of FIN 48 did not materially affect our operating results, financial position or cash flows. As of December 31, 2007, we have no liability reported for unrecognized tax benefits.

Our tax years are generally open to examination by the Internal Revenue Service and state revenue authorities for calendar years ending December 2006, 2005, and 2004.

16. SEGMENT INFORMATION

Our business is divided into operating segments, defined as components of the enterprise, about which financial information is available and evaluated regularly by our Chief Operating Decision Maker in deciding how resources are allocated and performance is assessed.

Each of our reportable segments is a business unit that offers different services and products that is managed separately, since each business segment requires different operating strategies. We have segregated our business activities into three distinct operating segments:

- Liquids;
- Natural Gas; and
- Marketing.

The following table presents certain financial information relating to our business segments as of and for the years ended December 31, 2007, 2006 and 2005.

	As of and for the Year Ended December 31, 2007				
	Liquids	Natural Gas	Marketing	Corporate[1]	Total
	(in millions)				
Total revenue	$ 548.1	$ 5,807.3	$ 3,527.5	$ —	$ 9,882.9
Less: Intersegment revenue	—	2,363.3	237.0	—	2,600.3
Operating revenue	548.1	3,444.0	3,290.5	—	7,282.6
Cost of natural gas	—	2,990.0	3,256.9	—	6,246.9
Operating and administrative	156.1	266.7	8.0	3.5	434.3
Power	117.0	—	—	—	117.0
Depreciation and amortization	67.9	96.1	1.6	—	165.6
Operating income	207.1	91.2	24.0	(3.5)	318.8
Interest expense	—	—	—	99.8	99.8
Other income	—	—	—	3.0	3.0
Income from continuing operations before income tax expense	207.1	91.2	24.0	(100.3)	222.0
Income tax expense	—	—	—	5.1	5.1
Income from continuing operations	207.1	91.2	24.0	(105.4)	216.9
Income from discontinued operations	—	32.6	—	—	32.6
Net income	$ 207.1	$ 123.8	$ 24.0	$ (105.4)	$ 249.5
Total assets	$ 2,976.9	$ 3,461.1	$ 349.6	$ 104.0	$ 6,891.6
Capital expenditures (excluding acquisitions)	$ 1,218.8	$ 747.9	$ 1.6	$ 11.9	$ 1,980.2

(1) Corporate consists of interest expense, interest income and other costs such as certain taxes, which are not allocated to the other business segments.

	As of and for the Year Ended December 31, 2006				
	Liquids	Natural Gas	Marketing	Corporate[1]	Total
			(in millions)		
Total revenue	$ 512.8	$ 5,404.1	$ 3,182.3	$ —	$ 9,099.2
Less: Intersegment revenue	—	2,383.4	206.8	—	2,590.2
Operating revenue	512.8	3,020.7	2,975.5	—	6,509.0
Cost of natural gas	—	2,601.1	2,913.5	—	5,514.6
Operating and administrative	141.3	215.4	5.4	2.7	364.8
Power	107.6	—	—	—	107.6
Depreciation and amortization	64.1	70.3	0.5	0.2	135.1
Operating income	199.8	133.9	56.1	(2.9)	386.9
Interest expense	—	—	—	110.5	110.5
Other income	—	—	—	8.5	8.5
Income from continuing operations before income taxes	199.8	133.9	56.1	(104.9)	284.9
Income tax expense	—	—	—	—	—
Income from continuing operations	199.8	133.9	56.1	(104.9)	284.9
Income from discontinued operations	—	—	—	—	—
Net income	$ 199.8	$ 133.9	$ 56.1	$ (104.9)	$ 284.9
Total assets	$ 1,816.4	$ 2,797.3	$ 366.9	$ 243.2	$ 5,223.8
Capital expenditures (excluding acquisitions)	$ 237.2	$ 614.8	$ 1.9	$ 10.5	$ 864.4

(1) Corporate consists of interest expense, interest income and other costs such as certain taxes, which are not allocated to the other business segments.

	As of and for the Year Ended December 31, 2005				
	Liquids	Natural Gas	Marketing	Corporate[1]	Total
			(in millions)		
Total revenue	$ 418.0	$ 4,945.1	$ 3,884.2	$ —	$ 9,247.3
Less: Intersegment revenue	—	2,593.0	177.4	—	2,770.4
Operating revenue	418.0	2,352.1	3,706.8	—	6,476.9
Cost of natural gas	—	2,018.7	3,744.6	—	5,763.3
Operating and administrative	144.2	175.0	4.1	3.5	326.8
Power	74.8	—	—	—	74.8
Depreciation and amortization	71.7	66.0	0.5	—	138.2
Gain on sale of assets	—	(18.1)	—	—	(18.1)
Operating income	127.3	110.5	(42.4)	(3.5)	191.9
Interest expense	—	—	—	107.7	107.7
Other income	—	—	—	5.0	5.0
Income from continuing operations before income taxes	127.3	110.5	(42.4)	(106.2)	89.2
Income tax expense	—	—	—	—	—
Income from continuing operations	127.3	110.5			
Income from discontinued operations	—	—	—	—	—
Net income	$ 127.3	$ 110.5	$ (42.4)	$ (106.2)	$ 89.2
Total assets	$ 1,664.0	$ 2,145.9	$ 512.3	$ 106.2	$ 4,428.4
Capital expenditures (excluding acquisitions)	$ 77.0	$ 263.8	$ 0.2	$ 3.8	$ 344.8

(1) Corporate consists of interest expense, interest income and other costs such as certain taxes, which are not allocated to the other business segments.

17. SUBSEQUENT EVENTS

On January 28, 2008, the board of directors of Enbridge Management declared a distribution payable to our partners on February 14, 2008. The distribution was paid to unitholders of record as of February 6, 2008, of our available cash of $96.7 million at December 31, 2007, or $0.950 per limited partner unit. Of this distribution, $66.0 million was paid in cash, $12.9 million was distributed in i-units to our i-unitholder, $17.2 million was distributed in Class C units to the holders of our Class C units and $0.6 million was retained from the General Partner in respect of the i-unit and Class C unit distributions to maintain its two percent general partner interest.

18. QUARTERLY FINANCIAL DATA (Unaudited)

	First		Second		Third		Fourth		Total	
	(in millions, except per unit amounts)									
2007 Quarters										
Operating revenue	$	1,712.7	$	1,738.7	$	1,710.9	$	2,120.3	$	7,282.6
Operating income	$	64.1	$	90.9	$	101.6	$	62.2	$	318.8
Income from continuing operations	$	39.1	$	68.6	$	77.3	$	31.9	$	216.9
Income from discontinued operations	$	—	$	—	$	—	$	32.6	$	32.6
Net income	$	39.1	$	68.6	$	77.3	$	64.5	$	249.5
Net income per limited partner unit(1)	$	0.40	$	0.69	$	0.75	$	0.59	$	2.45
2006 Quarters										
Operating revenue	$	1,888.6	$	1,424.7	$	1,532.3	$	1,663.4	$	6,509.0
Operating income(2)	$	108.0	$	93.6	$	108.7	$	76.6	$	386.9
Net income(2)	$	81.1	$	70.4	$	82.2	$	51.2	$	284.9
Net income per limited partner unit(1)(2)	$	1.12	$	0.96	$	1.03	$	0.56	$	3.62

(1) The General Partner's allocation of net income has been deducted before calculating net income per limited partner unit.

(2) The fourth quarter of 2006 includes approximately $8.3 million for raw natural gas purchases and transportation and fractionation charges that relate to prior years that we had not previously recorded.

Section 2: 10-K (10-K)

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Section 3: EX-21.1 (EXHIBIT 21.1)

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Exhibit 21.1

ENBRIDGE ENERGY PARTNERS, L.P.
Subsidiaries of the Registrant

Company Name	State of Incorporation/ Formation/Organization
Dufour Petroleum, L.P.	Delaware
Enbridge Energy, Limited Partnership	Delaware
Enbridge G & P (North Texas) L.P.	Texas
Enbridge Gathering (North Texas) L.P.	Texas
Enbridge Gathering (Texarkana) L.P.	Delaware
Enbridge Holdings (Texas Systems) L.L.C.	Delaware
Enbridge Liquids Marketing (North Texas) L.P.	Delaware
Enbridge Marketing (East Texas) L.P.	Delaware
Enbridge Marketing (North Texas) L.P.	Delaware
Enbridge Marketing (U.S.) L.L.C.	Delaware
Enbridge Marketing (U.S.) L.P.	Texas
Enbridge Midcoast Energy, L.P.	Texas
Enbridge Midcoast Holdings, L.L.C.	Delaware
Enbridge Midcoast Limited Holdings, L.L.C.	Delaware
Enbridge Offshore Pipelines (Seacrest) L.P.	Texas
Enbridge Offshore Pipelines (UTOS) LLC	Delaware
Enbridge Partners Risk Management, L.P.	Delaware
Enbridge Pipelines (Alabama Gathering) L.L.C.	Alabama
Enbridge Pipelines (Alabama Intrastate) L.L.C.	Alabama
Enbridge Pipelines (AlaTenn) L.L.C.	Alabama
Enbridge Pipelines (Bamagas Intrastate) L.L.C.	Delaware
Enbridge Pipelines (East Texas) L.P.	Delaware
Enbridge Pipelines (Lakehead) L.L.C.	Delaware
Enbridge Pipelines (Louisiana Intrastate) L.L.C.	Delaware
Enbridge Pipelines (Louisiana Liquids) L.L.C.	Delaware
Enbridge Pipelines (Midla) L.L.C.	Delaware
Enbridge Pipelines (NE Texas) L.P.	Delaware
Enbridge Pipelines (NE Texas Liquids) L.P.	Delaware
Enbridge Pipelines (North Dakota) LLC	Delaware
Enbridge Pipelines (North Texas) L.P.	Texas
Enbridge Pipelines (Ozark) L.L.C.	Delaware
Enbridge Pipelines (SIGCO Intrastate) L.L.C.	Delaware
Enbridge Pipelines (Tennessee River) L.L.C.	Alabama
Enbridge Pipelines (Texas Gathering) L.P.	Delaware
Enbridge Pipelines (Texas Intrastate) L.P.	Texas
Enbridge Pipelines (Wisconsin) Inc.	Wisconsin
Enbridge Processing (Mississippi) L.L.C.	Delaware

H&W Pipeline, L.L.C.	Alabama
Mid Louisiana Gas Transmission, L.L.C.	Delaware
Midcoast Holdings No. One, L.L.C.	Delaware
Nugget Drilling Corporation	Minnesota
Tri-State Holdings, LLC	Michigan

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Exhibit 21.1

Section 4: EX-23.1 (EXHIBIT 23.1)

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Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-131076) of Enbridge Energy Partners, L.P. of our report dated February 21, 2008 relating to the financial statements and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

PricewaterhouseCoopers LLP

Houston, Texas
February 21, 2008

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Exhibit 23.1

Section 5: EX-31.1 (EXHIBIT 31.1)

QuickLinks -- Click here to rapidly navigate through this document

Exhibit 31.1

CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Stephen J. J. Letwin, certify that:

1. I have reviewed this Annual Report on Form 10-K of Enbridge Energy Partners, L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's Board of Directors (or persons performing the equivalent functions):

    a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2008

/s/ Stephen J.J. Letwin

Stephen J. J. Letwin

Managing Director
(Principal Executive Officer)
Enbridge Energy Management, L.L.C. (as delegate of the General Partnership)

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Exhibit 31.1

CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

Section 6: EX-31.2 (EXHIBIT 31.2)

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Exhibit 31.2

CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Mark A. Maki, certify that:

1. I have reviewed this Annual Report on Form 10-K of Enbridge Energy Partners, L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's Board of Directors (or persons performing the equivalent functions):

    a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2008

/s/ Mark A. Maki

Mark A. Maki
Vice President, Finance
(Principal Financial Officer)
Enbridge Energy Management, L.L.C. (as delegate of the General Partnership)

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Exhibit 31.2

CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

Section 7: EX-32.1 (EXHIBIT 32.1)

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Exhibit 32.1

CERTIFICATE OF PRINCIPAL EXECUTIVE OFFICER
Pursuant to Section 906(a) of the Sarbanes-Oxley Act of 2002
Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18 United States Code

The undersigned, being the Principal Executive Officer of Enbridge Energy Partners, L.P. (the "Partnership"), hereby certifies that the Partnership's Annual Report on Form 10-K for the fiscal year ended December 31, 2007, filed with the United States Securities and Exchange Commission pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)), fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, and that information contained in such Annual Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to the Partnership and will be retained by the Partnership and furnished to the Securities and Exchange Commission or its staff upon request.

Date: February 21, 2008

/s/ Stephen J.J. Letwin

Stephen J. J. Letwin
Managing Director
(Principal Executive Officer)
Enbridge Energy Management, L.L.C. (as delegate of the General Partnership)

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Exhibit 32.1

CERTIFICATE OF PRINCIPAL EXECUTIVE OFFICER Pursuant to Section 906(a) of the Sarbanes-Oxley Act of 2002 Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18 United States Code

Section 8: EX-32.2 (EXHIBIT 32.2)

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Exhibit 32.2

CERTIFICATE OF PRINCIPAL FINANCIAL OFFICER
Pursuant to Section 906(a) of the Sarbanes-Oxley Act of 2002
Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18 United States Code

The undersigned, being the Principal Financial Officer of Enbridge Energy Partners, L.P. (the "Partnership"), hereby certifies that the Partnership's Annual Report on Form 10-K for the fiscal year ended December 31, 2007, filed with the United States Securities and Exchange Commission pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)), fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, and that information contained in such Annual Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to the Partnership and will be retained by the Partnership and furnished to the Securities and Exchange Commission or its staff upon request.

Date: February 21, 2008

/s/ Mark A. Maki

Mark A. Maki
Vice President, Finance
(Principal Financial Officer)
Enbridge Energy Management, L.L.C. (as delegate of the General Partnership)

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EPD 10-Q 9/30/2008

Section 1: 10-Q (QUARTERLY REPORT)

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

☑ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended September 30, 2008

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from ___ to ___.

Commission file number: 1-14323

ENTERPRISE PRODUCTS PARTNERS L.P.

(Exact name of Registrant as Specified in Its Charter)

Delaware	**76-0568219**
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)

1100 Louisiana, 10th Floor
Houston, Texas 77002
(Address of Principal Executive Offices, Including Zip Code)

(713) 381-6500
(Registrant's Telephone Number, Including Area Code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes ☑ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☑
Accelerated filer ☐
Non-accelerated filer ☐ (Do not check if a smaller reporting company)
Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes ☐ No ☑

There were 437,850,289 common units, including 2,239,613 restricted common units, of Enterprise Products Partners L.P. outstanding at November 3, 2008. These common units trade on the New York Stock Exchange under the ticker symbol "EPD."

ENTERPRISE PRODUCTS PARTNERS L.P.
TABLE OF CONTENTS

PART I. FINANCIAL INFORMATION.

Item 1. ***Financial Statements*****.**

ENTERPRISE PRODUCTS PARTNERS L.P.
UNAUDITED CONDENSED CONSOLIDATED BALANCE SHEETS
(Dollars in thousands)

ASSETS	September 30, 2008	December 31, 2007
Current assets:		
Cash and cash equivalents	$ 55,403	$ 39,722
Restricted cash	183,221	53,144
Accounts and notes receivable – trade, net of allowance for doubtful accounts of $15,781 at September 30, 2008 and $21,659 at December 31, 2007	1,840,584	1,930,762
Accounts receivable – related parties	88,871	79,782
Inventories	653,783	354,282
Prepaid and other current assets	161,233	80,193
Total current assets	2,983,095	2,537,885
Property, plant and equipment, net	12,693,619	11,587,264
Investments in and advances to unconsolidated affiliates	917,193	858,339
Intangible assets, net of accumulated amortization of $408,304 at September 30, 2008 and $341,494 at December 31, 2007	866,313	917,000
Goodwill	616,996	591,652
Deferred tax asset	2,927	3,522
Other assets, including restricted cash of $17,871 at December 31, 2007	69,067	112,345
Total assets	$ 18,149,210	$ 16,608,007
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Accounts payable – trade	$ 245,629	$ 324,999
Accounts payable – related parties	75,635	24,432
Accrued product payables	2,241,336	2,227,489
Accrued expenses	75,156	47,756
Accrued interest	101,962	130,971
Other current liabilities	430,377	289,036
Total current liabilities	3,170,095	3,044,683
Long-term debt: (see Note 10)		
Senior debt obligations – principal	7,184,201	5,646,500
Junior subordinated notes – principal	1,250,000	1,250,000
Other	23,994	9,645
Total long-term debt	8,458,195	6,906,145
Deferred tax liabilities	23,161	21,364
Other long-term liabilities	66,102	73,748
Minority interest	412,911	430,418
Commitments and contingencies		
Partners' equity: (see Note 11)		
Limited partners		
Common units (435,610,676 units outstanding at September 30, 2008 and 433,608,763 units outstanding at December 31, 2007)	5,990,461	5,976,947
Restricted common units (2,239,613 units outstanding at September 30, 2008 and 1,688,540 units outstanding at December 31, 2007)	23,869	15,948
General partner	122,639	122,297
Accumulated other comprehensive income (loss)	(118,223)	16,457
Total partners' equity	6,018,746	6,131,649
Total liabilities and partners' equity	$ 18,149,210	$ 16,608,007

See Notes to Unaudited Condensed Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED OPERATIONS
(Dollars in thousands, except per unit amounts)

	For the Three Months Ended September 30, 2008	For the Three Months Ended September 30, 2007	For the Nine Months Ended September 30, 2008	For the Nine Months Ended September 30, 2007
Revenues:				
Third parties	$ 5,997,743	$ 3,933,157	$ 17,498,445	$ 11,268,342
Related parties	300,159	178,839	823,607	379,314
Total revenues	6,297,902	4,111,996	18,322,052	11,647,656
Costs and expenses:				
Operating costs and expenses:				
Third parties	5,806,735	3,815,087	16,766,003	10,730,670
Related parties	165,207	81,324	477,067	250,892
Total operating costs and expenses	5,971,942	3,896,411	17,243,070	10,981,562
General and administrative costs:				
Third parties	8,354	7,211	22,307	21,414
Related parties	13,366	11,504	44,594	45,292
Total general and administrative costs	21,720	18,715	66,901	66,706
Total costs and expenses	5,993,662	3,915,126	17,309,971	11,048,268
Equity in earnings of unconsolidated affiliates	14,876	13,960	48,037	13,928
Operating income	319,116	210,830	1,060,118	613,316
Other income (expense):				
Interest expense	(102,657)	(85,075)	(290,412)	(219,708)
Interest income	2,095	2,300	4,708	6,743
Other, net	(917)	(594)	(1,968)	(362)
Total other expense, net	(101,479)	(83,369)	(287,672)	(213,327)
Income before provision for income taxes and minority interest	217,637	127,461	772,446	399,989
Provision for income taxes	(6,610)	(2,073)	(17,193)	(9,001)
Income before minority interest	211,027	125,388	755,253	390,988
Minority interest	(7,946)	(7,782)	(29,293)	(19,183)
Net income	$ 203,081	$ 117,606	$ 725,960	$ 371,805
Net income allocation: (see Note 11)				
Limited partners' interest in net income	$ 167,625	$ 88,408	$ 620,494	$ 286,984
General partner's interest in net income	$ 35,456	$ 29,198	$ 105,466	$ 84,821
Earning per unit: (see Note 14)				
Basic and diluted income per unit	$ 0.38	$ 0.20	$ 1.42	$ 0.66

See Notes to Unaudited Condensed Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED COMPREHENSIVE INCOME (LOSS)
(Dollars in thousands)

	For the Three Months Ended September 30, 2008	For the Three Months Ended September 30, 2007	For the Nine Months Ended September 30, 2008	For the Nine Months Ended September 30, 2007
Net income	$ 203,081	$ 117,606	$ 725,960	$ 371,805
Other comprehensive income (loss):				
Cash flow hedges: (see Note 4)				
Foreign currency hedge gains (losses)	--	2,879	(1,308)	2,879
Net commodity financial instrument losses	(215,540)	(22,292)	(108,294)	(21,446)
Net interest rate financial instrument gains (losses)	(242)	373	(21,283)	40,637
Less: Amortization of cash flow financing hedges	(800)	(1,096)	(3,983)	(3,365)
Total cash flow hedges	(216,582)	(20,136)	(134,868)	18,705
Foreign currency translation adjustment	377	1,832	452	2,381
Change in funded status of Dixie benefit plans, net of tax	--	--	(264)	--
Total other comprehensive income (loss)	(216,205)	(18,304)	(134,680)	21,086
Comprehensive income (loss)	$ (13,124)	$ 99,302	$ 591,280	$ 392,891

See Notes to Unaudited Condensed Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED CASH FLOWS
(Dollars in thousands)

	For the Nine Months Ended September 30, 2008	2007
Operating activities:		
Net income	$ 725,960	$ 371,805
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion in operating costs and expenses	408,601	374,522
Depreciation and amortization in general and administrative costs	8,137	7,129
Amortization in interest expense	(3,161)	432
Equity in earnings of unconsolidated affiliates	(48,037)	(13,928)
Distributions received from unconsolidated affiliates	69,852	52,343
Operating lease expense paid by EPCO, Inc.	1,579	1,579
Minority interest	29,293	19,183
Loss (gain) from asset sales and related transactions	(1,710)	5,445
Deferred income tax expense	5,580	5,542
Changes in fair market value of financial instruments	5,461	3,511
Effect of pension settlement recognition	(114)	--
Net effect of changes in operating accounts (see Note 17)	(228,397)	110,272
Net cash flows provided by operating activities	973,044	937,835
Investing activities:		
Capital expenditures	(1,485,654)	(1,684,455)
Contributions in aid of construction costs	21,215	52,462
Proceeds from asset sales and related transactions	1,685	1,933
Increase in restricted cash	(112,207)	(79,535)
Cash used for business combinations	(57,090)	(785)
Acquisition of intangible assets	(5,126)	--
Investments in unconsolidated affiliates	(35,307)	(318,491)
Advances to unconsolidated affiliates	(36,719)	(10,624)
Cash used in investing activities	(1,709,203)	(2,039,495)
Financing activities:		
Borrowings under debt agreements	6,360,387	4,926,858
Repayments of debt	(4,824,000)	(3,459,881)
Debt issuance costs	(8,793)	(15,281)
Distributions paid to partners	(770,848)	(711,739)
Distributions paid to minority interests	(39,196)	(20,485)
Proceeds from initial public offering of Duncan Energy Partners in minority interest	--	290,466
Other contributions from minority interests	28	12,506
Monetization of interest rate hedging financial instruments (see Note 4)	(22,144)	48,895
Repurchase of option awards	--	(1,568)
Acquisition of treasury units	(795)	--
Net proceeds from issuance of common units	57,181	52,804
Cash provided by financing activities	751,820	1,122,575
Effect of exchange rate changes on cash flows	20	347
Net change in cash and cash equivalents	15,661	20,915
Cash and cash equivalents, January 1	39,722	22,619
Cash and cash equivalents, September 30	$ 55,403	$ 43,881

See Notes to Unaudited Condensed Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED PARTNERS' EQUITY
(See Note 11 for Unit History, Detail of Changes in Limited Partners' Equity and Accumulated Other Comprehensive Income (Loss))
(Dollars in thousands)

	Limited Partners	General Partner	Accumulated Other Comprehensive Income (Loss)	Total
Balance, December 31, 2007	$ 5,992,895	$ 122,297	$ 16,457	$ 6,131,649
Net income	620,494	105,466	--	725,960
Operating leases paid by EPCO, Inc.	1,548	31	--	1,579
Cash distributions to partners	(663,946)	(106,352)	--	(770,298)
Unit option reimbursements to EPCO, Inc.	(550)	--	--	(550)
Non-cash distributions	(5,006)	(100)	--	(5,106)
Acquisition of treasury units	(779)	(16)	--	(795)
Net proceeds from issuance of common units	55,363	1,130	--	56,493
Proceeds from exercise of unit options	680	8	--	688
Amortization of unit-based awards	13,631	175	--	13,806
Change in funded status of Dixie benefit plans, net of tax	--	--	(264)	(264)
Foreign currency translation adjustment	--	--	452	452
Cash flow hedges	--	--	(134,868)	(134,868)
Balance, September 30, 2008	$ 6,014,330	$ 122,639	$ (118,223)	$ 6,018,746

See Notes to Unaudited Condensed Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Except per unit amounts, or as noted within the context of each footnote disclosure, the dollar amounts presented in the tabular data within these footnote disclosures are stated in thousands of dollars.

Note 1. Partnership Organization

Partnership Organization

Enterprise Products Partners L.P. is a publicly traded Delaware limited partnership, the common units of which are listed on the New York Stock Exchange ("NYSE") under the ticker symbol "EPD." Unless the context requires otherwise, references to "we," "us," "our" or "Enterprise Products Partners" are intended to mean the business and operations of Enterprise Products Partners L.P. and its consolidated subsidiaries.

We were formed in April 1998 to own and operate certain natural gas liquids ("NGLs") related businesses of EPCO, Inc. ("EPCO"). We conduct substantially all of our business through our wholly owned subsidiary, Enterprise Products Operating LLC ("EPO"). We are owned 98% by our limited partners and 2% by Enterprise Products GP, LLC (our general partner, referred to as "EPGP"). EPGP is owned 100% by Enterprise GP Holdings L.P. ("Enterprise GP Holdings"), a publicly traded affiliate, the units of which are listed on the NYSE under the ticker symbol "EPE." The general partner of Enterprise GP Holdings is EPE Holdings, LLC ("EPE Holdings"), a wholly owned subsidiary of Dan Duncan LLC, the membership interests of which are owned by Dan L. Duncan. We, EPGP, Enterprise GP Holdings, EPE Holdings and Dan Duncan LLC are affiliates and under common control of Dan L. Duncan, the Group Co-Chairman and controlling shareholder of EPCO.

References to "TEPPCO" mean TEPPCO Partners, L.P., a publicly traded affiliate, the common units of which are listed on the NYSE under the ticker symbol "TPP." References to "TEPPCO GP" refer to Texas Eastern Products Pipeline Company, LLC, which is the general partner of TEPPCO and is wholly owned by Enterprise GP Holdings.

References to "Energy Transfer Equity" mean the business and operations of Energy Transfer Equity, L.P. and its consolidated subsidiaries. References to "LE GP" mean LE GP, LLC, which is the general partner of Energy Transfer Equity. On May 7, 2007, Enterprise GP Holdings acquired non-controlling interests in both LE GP and Energy Transfer Equity. Enterprise GP Holdings accounts for its investments in LE GP and Energy Transfer Equity using the equity method of accounting.

References to "Employee Partnerships" mean EPE Unit L.P. ("EPE Unit I"), EPE Unit II, L.P. ("EPE Unit II"), EPE Unit III, L.P. ("EPE Unit III") and Enterprise Unit L.P. ("Enterprise Unit"), collectively, which are private company affiliates of EPCO.

On February 5, 2007, a consolidated subsidiary of ours, Duncan Energy Partners L.P. ("Duncan Energy Partners"), completed an initial public offering of its common units (see Note 13). Duncan Energy Partners owns equity interests in certain of our midstream energy businesses. References to "DEP GP" mean DEP Holdings, LLC, which is the general partner of Duncan Energy Partners and is wholly owned by EPO.

For financial reporting purposes, we consolidate the financial statements of Duncan Energy Partners with those of our own and reflect its operations in our business segments. We control Duncan Energy Partners through our ownership of its general partner. Also, due to common control of the entities by Dan L. Duncan, the initial consolidated balance sheet of Duncan Energy Partners reflects our historical carrying basis in each of the subsidiaries contributed to Duncan Energy Partners. Public ownership of Duncan Energy Partners' net assets and earnings are presented as a component of minority interest in our condensed consolidated financial statements. The borrowings of Duncan Energy Partners are presented as part of our consolidated debt; however, neither Enterprise Products Partners L.P. nor EPO have any obligation for the payment of interest or repayment of borrowings incurred by Duncan Energy Partners.

Basis of Presentation

Our results of operations for the three and nine months ended September 30, 2008 are not necessarily indicative of results expected for the full year.

Essentially all of our assets, liabilities, revenues and expenses are recorded at EPO's level in our consolidated financial statements. Enterprise Products Partners L.P. acts as guarantor of certain of EPO's debt obligations. See Note 18 for condensed consolidated financial information of EPO.

In our opinion, the accompanying Unaudited Condensed Consolidated Financial Statements include all adjustments consisting of normal recurring accruals necessary for fair presentation. Although we believe the disclosures in these financial statements are adequate to make the information presented not misleading, certain information and footnote disclosures normally included in annual financial statements prepared in accordance with U.S. generally accepted accounting principles ("GAAP") have been condensed or omitted pursuant to the rules and regulations of the U.S. Securities and Exchange Commission ("SEC"). These Unaudited Condensed Consolidated Financial Statements and notes thereto should be read in conjunction with our Annual Report on Form 10-K for the year ended December 31, 2007 (Commission File No. 1-14323).

Note 2. General Accounting Policies and Related Matters

Consolidation Policy

Our financial statements include our accounts and those of our majority-owned subsidiaries in which we have a controlling financial or equity interest, after the elimination of intercompany accounts and transactions. We evaluate our financial interests in companies to determine if they represent variable interest entities where we are the primary beneficiary. If such criteria are met, we consolidate the financial statements of such businesses with those of our own.

If an investee is organized as a limited partnership or limited liability company and maintains separate ownership accounts, we account for our investment using the equity method if our ownership interest is between 3% and 50% and we exercise significant influence over the investee's operating and financial policies. For all other types of investments, we apply the equity method of accounting if our ownership interest is between 20% and 50% and we exercise significant influence over the investee's operating and financial policies. In consolidation we eliminate our proportionate share of profits and losses from transactions with our equity method unconsolidated affiliates to the extent such amounts are material and remain on our balance sheet (or those of our equity method investees) in inventory or similar accounts.

If our ownership interest in an investee does not provide us with either control or significant influence over the investee, we account for the investment using the cost method.

Dixie Employee Benefit Plans

Dixie Pipeline Company ("Dixie"), a consolidated subsidiary of EPO, directly employs the personnel that operate its pipeline system. Certain of these employees are eligible to participate in Dixie's defined contribution plan and pension and postretirement benefit plans.

Defined Contribution Plan. Dixie contributed $0.1 million to its company-sponsored defined contribution plan during each of the three month periods ended September 30, 2008 and 2007. During each of the nine month periods ended September 30, 2008 and 2007, Dixie contributed $0.2 million to its company-sponsored defined contribution plan.

Pension and Postretirement Benefit Plans. Dixie's net pension benefit costs were $0.1 million for each of the three month periods ended September 30, 2008 and 2007. For each of the nine month periods ended September 30, 2008 and 2007, Dixie's net pension benefit costs were $0.4 million. Dixie's net postretirement benefit costs were $0.1 million for each of the three month periods ended September 30, 2008 and 2007. For each of the nine month periods ended September 30, 2008 and 2007, Dixie's net postretirement benefit costs were $0.3 million. During the remainder of 2008, Dixie expects to contribute approximately $0.5 million to its pension plan and approximately $0.1 million to its postretirement benefit plan.

Environmental Costs

Environmental costs for remediation are accrued based on estimates of known remediation requirements. Such accruals are based on management's best estimate of the ultimate cost to remediate a site and are adjusted as further information and circumstances develop. Those estimates may change substantially depending on information about the nature and extent of contamination, appropriate remediation technologies and regulatory approvals. Ongoing environmental compliance costs are charged to expense as incurred. In accruing for environmental remediation liabilities, costs of future expenditures for environmental remediation are not discounted to their present value, unless the amount and timing of the expenditures are fixed or reliably determinable. At September 30, 2008, none of our estimated environmental remediation liabilities are discounted to present value since the ultimate amount and timing of cash payments for such liabilities are not readily determinable. Expenditures to mitigate or prevent future environmental contamination are capitalized.

At September 30, 2008 and December 31, 2007, our accrued liabilities for environmental remediation projects totaled $21.2 million and $26.5 million, respectively. These amounts were derived from a range of reasonable estimates based upon studies and site surveys. Unanticipated changes in circumstances and/or legal requirements could result in expenses being incurred in future periods in addition to an increase in actual cash required to remediate contamination for which we are responsible.

Estimates

Preparing our financial statements in conformity with GAAP requires management to make estimates and assumptions that affect amounts presented in the financial statements (i.e. assets, liabilities, revenue and expenses) and disclosures about contingent assets and liabilities. Our actual results could differ from these estimates. On an ongoing basis, management reviews its estimates based on currently available information. Changes in facts and circumstances may result in revised estimates.

We revised the remaining useful lives of certain assets, most notably the assets that constitute our Texas Intrastate System, effective January 1, 2008. This revision adjusted the remaining useful life of such assets to incorporate recent data showing that proved natural gas reserves supporting throughput and processing volumes for these assets have changed since our original determination made in September 2004. These revisions will prospectively reduce our depreciation expense on assets having carrying values totaling $2.72 billion at January 1, 2008. For additional information regarding this change in estimate, see Note 6.

Minority Interest

As presented in our Unaudited Condensed Consolidated Balance Sheets, minority interest represents third-party and affiliate ownership interests in the net assets of our consolidated subsidiaries. For financial reporting purposes, the assets and liabilities of our controlled subsidiaries, including Duncan Energy Partners, are consolidated with those of our own, with any third-party or affiliate ownership interests in such amounts presented as minority interest.

At September 30, 2008 and December 31, 2007, minority interest includes $281.9 million and $288.6 million, respectively, attributable to third party owners of Duncan Energy Partners. Minority interest expense for the three months ended September 30, 2008 and 2007 includes $2.7 million and $3.2

million, respectively, attributable to third party owners of Duncan Energy Partners. For the nine months ended September 30, 2008 and 2007 minority interest expense attributable to third party owners of Duncan Energy Partners was $11.9 million and $9.4 million, respectively. The remaining minority interest expense amounts for 2008 and 2007 are attributable to our other consolidated affiliates.

Contributions from minority interests for the nine months ended September 30, 2007 includes approximately $291.0 million received from third parties in connection with the initial public offering of Duncan Energy Partners in February 2007.

Recent Accounting Developments

The following information summarizes recently issued accounting guidance since those reported in our Annual Report on Form 10-K for the year ended December 31, 2007 that will or may affect our future financial statements.

Statement of Financial Accounting Standards ("SFAS") No. 161, Disclosures about Derivative Instruments and Hedging Activities – An Amendment of FASB Statement No. 133. Issued in March 2008, SFAS 161 changes the disclosure requirements for financial instruments and hedging activities with the intent to provide users of financial statements with an enhanced understanding of (i) how and why an entity uses financial instruments, (ii) how financial instruments and related hedged items are accounted for under SFAS 133, Accounting for Derivative Instruments and Hedging Activities, and its related interpretations and (iii) how financial instruments and related hedged items affect an entity's financial position, financial performance and cash flows. SFAS 161 requires qualitative disclosures about objectives and strategies for using financial instruments, quantitative disclosures about fair value amounts of and gains and losses on financial instruments and disclosures about credit-risk-related contingent features in financial instrument agreements. This statement has the same scope as SFAS 133, and accordingly applies to all entities. SFAS 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early application encouraged. This statement encourages, but does not require, comparative disclosures for earlier periods at initial adoption. SFAS 161 only affects disclosure requirements; therefore, our adoption of this statement effective January 1, 2009 will not impact our financial position, results of operations or cash flows.

Emerging Issues Task Force ("EITF") 07-4, Application of the Two Class Method Under FASB Statement No. 128, Earnings Per Share, to Master Limited Partnerships ("MLP"). EITF 07-4 was issued during the first quarter of 2008 and prescribes the manner in which a MLP should allocate and present earnings per unit using the two-class method set forth in SFAS 128, Earnings Per Share. Under the two-class method, current period earnings are allocated to the general partner (including earnings attributable to any embedded incentive distribution rights) and limited partners according to the distribution formula for available cash set forth in the MLP's partnership agreement. EITF 07-4 is effective for us on January 1, 2009. We do not believe that EITF 07-4 will have a material impact on our earnings per unit computations and disclosures.

FASB Staff Position ("FSP") No. EITF 03-6-1, Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities. FSP EITF 03-6-1 was issued in June 2008. FSP EITF 03-6-1 clarifies that unvested share-based payment awards constitute participating securities, if such awards include nonforfeitable rights to dividends or dividend equivalents. Consequently, awards that are deemed to be participating securities must be allocated earnings in the computation of earnings per share under the two-class method. FSP EITF 03-6-1 is effective for us on January 1, 2009. We do not believe that FSP EITF 03-6-1 will have a material impact on our earnings per unit computations and disclosures.

FSP No. FAS 157-2, Effective Date of FASB Statement No. 157. FSP 157-2 defers the effective date of SFAS 157, Fair Value Measurements, to fiscal years beginning after November 15, 2008, and interim periods within those fiscal years, for all nonfinancial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). As allowed under FSP 157-2, we have not applied the provisions of SFAS 157 to our nonfinancial assets and liabilities measured at fair value, which include certain assets and liabilities acquired in business combinations. On January 1, 2008, we adopted the provisions of SFAS 157 that apply to financial assets and liabilities. See Note 4 for these fair value disclosures. We do not expect any immediate impact from adoption of the remaining portions of SFAS 157 on January 1, 2009.

In light of current market conditions, the FASB has issued additional clarifying guidance regarding the implementation of SFAS 157, particularly with respect to financial assets that do not trade in active markets such as investments in joint ventures. This clarifying guidance did not result in a change in our accounting, reporting or impairment testing for such investments. We continue to monitor developments at the FASB and SEC for new matters and guidance that may affect our valuation processes.

FSP No. FAS 142-3, Determination of the Useful Life of Intangible Assets. In April 2008, the FASB issued FSP 142-3, which amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful lives of recognized intangible assets under SFAS 142, Goodwill and Other Intangible Assets. This change is intended to improve consistency between the useful life of a recognized intangible asset under SFAS 142 and the period of expected cash flows used to measure the fair value of such assets under SFAS 141(R) and other accounting guidance. The requirement for determining useful lives must be applied prospectively to intangible assets acquired after January 1, 2009 and the disclosure requirements must be applied prospectively to all intangible assets recognized as of, and subsequent to, January 1, 2009. We will adopt the provisions of FSP 142-3 on January 1, 2009.

Restricted Cash

Restricted cash represents amounts held in connection with our commodity financial instruments portfolio and New York Mercantile Exchange ("NYMEX") physical natural gas purchases. Additional cash may be restricted to maintain our positions as commodity prices fluctuate or deposit requirements change. At December 31, 2007, restricted cash also included amounts held by a third party trustee charged with disbursing proceeds from our Petal GO Zone bond offering. As of June 30, 2008, all proceeds from the Petal GO Zone bonds had been released by the trustee to fund construction costs associated with the expansion of our Petal, Mississippi storage facility. The following table presents the components of our restricted cash balances at the periods indicated:

	September 30, 2008	December 31, 2007
Amounts held in brokerage accounts related to		
commodity hedging activities and physical natural gas purchases	$ 183,221	$ 53,144
Proceeds from Petal GO Zone bonds reserved for construction costs	--	17,871
Total restricted cash	$ 183,221	$ 71,015

Note 3. Accounting for Unit-Based Awards

We account for unit-based awards in accordance with SFAS 123(R), Share-Based Payment. SFAS 123(R) requires us to recognize compensation expense related to unit-based awards based on the fair value of the award at grant date. The fair value of restricted unit awards is based on the market price of the underlying common units on the date of grant. The fair value of other unit-based awards is estimated using the Black-Scholes option pricing model. The fair value of an equity-classified award (such as a restricted unit award) is amortized to earnings on a straight-line basis over the requisite service or vesting period. Compensation expense for liability-classified awards (such as unit appreciation rights ("UARs")) is recognized over the requisite service or vesting period of an award based on the fair value of the award remeasured at each reporting period. Liability-type awards are settled in cash upon vesting.

The following table summarizes our unit-based compensation expense amounts by plan during each of the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2008	2007	2008	2007
EPCO 1998 Long-Term Incentive Plan ("1998 Plan")				
Unit options	$ 116	$ 139	$ 329	$ 4,248
Restricted units	2,569	1,981	6,121	5,639
Total 1998 Plan (1)	2,685	2,120	6,450	9,887
Enterprise Products 2008 Long-Term Incentive Plan ("2008 LTIP")				
Unit options	36	--	50	--
Total 2008 LTIP	36	--	50	--
Employee Partnerships	1,540	1,364	4,099	2,542
DEP GP Unit Appreciation Rights	(1)	23	5	58
Total consolidated expense	$ 4,260	$ 3,507	$ 10,604	$ 12,487

(1) Amounts presented for the nine months ended September 30, 2007 include $4.6 million associated with the resignation of our former Chief Executive Officer.

1998 Plan

The 1998 Plan provides for the issuance of up to 7,000,000 of our common units. After giving effect to outstanding option awards at September 30, 2008 and the issuance and forfeiture of restricted unit awards through September 30, 2008, a total of 771,546 additional common units could be issued under the 1998 Plan.

Unit option awards. Under the 1998 Plan, non-qualified incentive options to purchase a fixed number of our common units may be granted to key employees of EPCO who perform management, administrative or operational functions for us. The following table presents unit option activity under the 1998 Plan for the periods indicated:

	Number of Units	Weighted-Average Strike Price (dollars/unit)	Weighted-Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (1)
Outstanding at December 31, 2007 (2)	2,315,000	$ 26.18		
Exercised	(61,500)	$ 20.38		
Forfeited or terminated	(85,000)	$ 26.72		
Outstanding at September 30, 2008	2,168,500	$ 26.32	5.44	$ 2,356
Options exercisable at September 30, 2008	548,500	$ 21.47	4.33	$ 2,356

(1) Aggregate intrinsic value reflects fully vested unit options at September 30, 2008.
(2) During 2008, we amended the terms of certain of our outstanding unit options. In general, the expiration dates of these awards were modified from May and August 2017 to December 2012.

The total intrinsic value of unit options exercised during the three and nine months ended September 30, 2008 was $0.1 million and $0.6 million, respectively. At September 30, 2008, there was an estimated $1.9 million of total unrecognized compensation cost related to nonvested unit options granted under the 1998 Plan. We expect to recognize our share of this cost over a weighted-average period of 2.4 years in accordance with the EPCO administrative services agreement (the "ASA").

During the nine months ended September 30, 2008 and 2007, we received cash of $0.7 million and $7.7 million, respectively, from the exercise of unit options. Conversely, our option-related reimbursements to EPCO were $0.6 million and $2.9 million, respectively.

Restricted unit awards. Under the 1998 Plan, we may also issue restricted common units to key employees of EPCO and directors of our general partner. The following table summarizes information regarding our restricted common units for the periods indicated:

	Number of Units	Weighted-Average Grant Date Fair Value per Unit (1)
Restricted units at December 31, 2007	1,688,540	
Granted (2)	750,900	$ 25.30
Forfeited	(84,677)	$ 26.83
Vested	(115,150)	$ 22.83
Restricted units at September 30, 2008	2,239,613	

(1) Determined by dividing the aggregate grant date fair value of awards by the number of awards issued. The weighted-average grant date fair value per unit for forfeited and vested awards is determined before an allowance for forfeitures.
(2) Aggregate grant date fair value of restricted common unit awards issued during 2008 was $19.0 million based on a grant date market price of our common units ranging from $28.21 to $32.31 per unit and an estimated forfeiture rate of 17.0%.

The total fair value of our restricted unit awards that vested during the three and nine months ended September 30, 2008 was $1.2 million and $2.6 million, respectively. As of September 30, 2008, there was $34.6 million of total unrecognized compensation cost related to restricted common units. We will recognize our share of such costs in accordance with the EPCO ASA. At September 30, 2008, these costs are expected to be recognized over a weighted-average period of 2.4 years.

Phantom unit awards. The 1998 Plan also provides for the issuance of phantom unit awards. These liability awards are automatically redeemed for cash based on the vested portion of the fair market value of the phantom units at redemption dates in each award. No phantom unit awards have been issued to date under the 1998 Plan.

2008 LTIP

On January 29, 2008, our unitholders approved the 2008 LTIP, which provides for awards of our common units and other rights to our non-employee directors and to consultants and employees of EPCO and its affiliates providing services to us. Awards under the 2008 LTIP may be granted in the form of unit options, restricted units, phantom units, UARs and distribution equivalent rights. The 2008 LTIP is administered by EPGP's Audit, Conflicts and Governance ("ACG") Committee. The 2008 LTIP provides for the issuance of up to 10,000,000 of our common units. After giving effect to option awards outstanding at September 30, 2008, a total of 9,205,000 additional common units could be issued under the 2008 LTIP.

The 2008 LTIP may be amended or terminated at any time by the Board of Directors of EPCO or EPGP's ACG Committee; however, the rules of the NYSE require that any material amendment, such as a significant increase in the number of common units available under the plan or a change in the types of awards available under the plan, would require the approval of our unitholders. The ACG Committee is also authorized to make adjustments in the terms and conditions of, and the criteria included in, awards under the plan in specified circumstances. The 2008 LTIP is effective until the earlier of January 29, 2018 or the time which all available units under the incentive plan have been delivered to participants or the time of termination of the plan by EPCO or EPGP's ACG Committee.

Unit option awards. The exercise price of unit options awarded to participants is determined by the ACG Committee (at its discretion) at the date of grant and may be no less than the fair market value of our common units at the date of grant. The following table presents unit option activity under the 2008 LTIP for the periods indicated:

	Number of Units	Weighted-Average Strike Price (dollars/unit)	Weighted-Average Remaining Contractual Term (in years)
Outstanding at January 29, 2008	--		
Granted (1)	795,000	$ 30.93	
Outstanding at September 30, 2008	795,000	$ 30.93	5.25

(1) Aggregate grant date fair value of these unit options issued during 2008 was $1.6 million based on the following assumptions: (i) a grant date market price of our common units of $30.93 per unit; (ii) expected life of options of 4.7 years; (iii) risk-free interest rate of 3.3%; (iv) expected distribution yield on our common units of 7.0%; (v) expected unit price volatility on our common units of 19.8%; and (vi) an estimated forfeiture rate of 17.0%.

At September 30, 2008, there was an estimated $1.4 million of total unrecognized compensation cost related to nonvested unit options granted under the 2008 LTIP. We expect to recognize our share of this cost over a remaining period of 3.6 years in accordance with the EPCO ASA.

Employee Partnerships

EPCO formed the Employee Partnerships to serve as an incentive arrangement for key employees of EPCO by providing them a "profits interest" in the Employee Partnerships. Currently, there are four Employee Partnerships: EPE Unit I, EPE Unit II, EPE Unit III and Enterprise Unit. EPE Unit I was formed in August 2005 in connection with Enterprise GP Holdings' initial public offering, EPE Unit II was formed in December 2006, EPE Unit III was formed in May 2007 and Enterprise Unit was formed in February 2008. For a detailed description of EPE Unit I, EPE Unit II and EPE Unit III, see our Annual Report on Form 10-K for the year ended December 31, 2007.

In July 2008, each of EPE Unit I, EPE Unit II and EPE Unit III entered into a second amendment to its respective agreement of limited partnership ("Second Amendment"). The Second Amendments for EPE Unit I and EPE Unit II provide for the reduction of the rate at which the Class A Limited Partner, Duncan Family Interests, Inc., earns a preferred return on its investment in EPE Unit I and EPE Unit II ("Class A Preference Return Rate"). The Class A Preference Return Rate in each of these two limited partnership agreements was reduced from 6.25% to a floating preference rate to be determined by EPCO (in its sole discretion) that will be between 4.50% and 5.725% per annum. The Second Amendment for EPE Unit I and EPE Unit II also provides that the liquidation date of these partnerships be extended to November 2012 and February 2014, respectively. The Second Amendment for EPE Unit III extends the liquidation date of EPE Unit III to May 2014. Collectively, the Second Amendment to these partnership agreements resulted in an aggregate $18.2 million increase in non-cash compensation costs attributable to the profits interest awards in EPE Unit I, EPE Unit II and EPE Unit III.

As of September 30, 2008, there was $43.4 million of total unrecognized compensation cost related to the four Employee Partnerships. We will recognize our share of these costs in accordance with the EPCO ASA over a weighted-average period of 5.2 years.

Enterprise Unit. On February 20, 2008, EPCO formed Enterprise Unit to serve as an incentive arrangement for certain employees of EPCO through a "profits interest" in Enterprise Unit. On that date, EPCO Holdings, Inc. ("EPCO Holdings") agreed to contribute $18.0 million in the aggregate (the "Initial Contribution") to Enterprise Unit and was admitted as the Class A limited partner. Certain key employees of EPCO, including our Chief Executive Officer and Chief Financial Officer, were issued Class B limited partner interests and admitted as Class B limited partners of Enterprise Unit without any capital contributions. EPCO Holdings made capital contributions to Enterprise Unit in addition to its Initial

Contribution and may make additional contributions, although it has no legal obligation to do so. As of September 30, 2008, EPCO Holdings has contributed a total of $51.5 million to Enterprise Unit.

As with the awards granted in connection with the other Employee Partnerships, these awards are designed to provide additional long-term incentive compensation for certain employees. The profits interest awards (or Class B limited partner interests) in Enterprise Unit entitle the holder to participate in the appreciation in value of Enterprise GP Holdings' units and our common units and are subject to early vesting or forfeiture upon the occurrence of certain events.

An allocated portion of the fair value of these equity awards will be charged to us under the EPCO ASA as a non-cash expense. We will not reimburse EPCO, Enterprise Unit or any of their affiliates or partners, through the ASA or otherwise, in cash for any expenses related to Enterprise Unit, including the Initial Contribution by EPCO Holdings.

The Class B limited partner interests in Enterprise Unit that are owned by EPCO employees are subject to forfeiture if the participating employee's employment with EPCO and its affiliates is terminated prior to February 20, 2014, with customary exceptions for death, disability and certain retirements that will result in early vesting. The risk of forfeiture associated with the Class B limited partner interests in Enterprise Unit will also lapse (i.e. the interests will become vested) upon certain change of control events.

Unless otherwise agreed to by EPCO, EPCO Holdings and a majority in interest of the Class B limited partners of Enterprise Unit, Enterprise Unit will terminate at the earlier of February 20, 2014 (six years from the date of the agreement) or a change in control of us or Enterprise GP Holdings. Enterprise Unit has the following material terms regarding its quarterly cash distribution to partners:

- Distributions of cash flow – Each quarter, 100% of the cash distributions received by Enterprise Unit from Enterprise GP Holdings and us will be distributed to the Class A limited partner until EPCO Holdings has received an amount equal to the Class A preferred return (as defined below), and any remaining distributions received by Enterprise Unit will be distributed to the Class B limited partners. The Class A preferred return equals the Class A capital base (as defined below) multiplied by 5.0% per annum. The Class A limited partner's capital base equals the amount of any contributions of cash or cash equivalents made by the Class A limited partner to Enterprise Unit, plus any unpaid Class A preferred return from prior periods, less any distributions made by Enterprise Unit of proceeds from the sale of units owned by Enterprise Unit (as described below).

- Liquidating Distributions – Upon liquidation of Enterprise Unit, units having a fair market value equal to the Class A limited partner capital base will be distributed to EPCO Holdings, plus any accrued and unpaid Class A preferred return for the quarter in which liquidation occurs. Any remaining units will be distributed to the Class B limited partners.

- Sale Proceeds – If Enterprise Unit sells any units that it beneficially owns, the sale proceeds will be distributed to the Class A limited partner and the Class B limited partners in the same manner as liquidating distributions described above.

DEP GP UARs

The non-employee directors of DEP GP, the general partner of Duncan Energy Partners, have been granted UARs in the form of letter agreements. These liability awards are not part of any established long-term incentive plan of EPCO, Enterprise GP Holdings, Duncan Energy Partners or us. These UARs entitle each non-employee director to receive a cash payment on the vesting date equal to the excess, if any, of the fair market value of Enterprise GP Holdings' units (determined as of a future vesting date) over the grant date fair value. These UARs are accounted for similarly to liability awards under SFAS 123(R) since they will be settled with cash. At September 30, 2008 and December 31, 2007, we had a total of 90,000 outstanding UARs granted to non-employee directors of DEP GP that cliff vest in 2012. If a director resigns prior to vesting, his UAR awards are forfeited.

Note 4. Financial Instruments

We are exposed to financial market risks, including changes in commodity prices, interest rates and foreign exchange rates. We may use financial instruments (e.g., futures, forwards, swaps, options and other financial instruments with similar characteristics) to mitigate the risks of certain identifiable and anticipated transactions. In general, the types of risks we attempt to hedge are those related to (i) the variability of future earnings, (ii) fair values of certain debt instruments and (iii) cash flows resulting from changes in applicable interest rates, commodity prices or exchange rates.

We recognize financial instruments as assets and liabilities on our Unaudited Condensed Consolidated Balance Sheets based on fair value. Fair value is generally defined as the amount at which a financial instrument could be exchanged in a current transaction between willing parties, not in a forced or liquidation sale. The estimated fair values of our financial instruments have been determined using available market information and appropriate valuation techniques. We must use considerable judgment, however, in interpreting market data and developing these estimates. Accordingly, our fair value estimates are not necessarily indicative of the amounts that we could realize upon disposition of these instruments. The use of different market assumptions and/or estimation techniques could have a material effect on our estimates of fair value.

Changes in fair value of financial instrument contracts are recognized in earnings in the current period unless specific hedge accounting criteria are met. If the financial instrument meets the criteria of a fair value hedge, gains and losses incurred on the instrument will be recorded in earnings to offset corresponding losses and gains on the hedged item. If the financial instrument meets the criteria of a cash flow hedge, gains and losses incurred on the instrument are recorded in accumulated other comprehensive income. Gains and losses on cash flow hedges are reclassified from accumulated other comprehensive income to earnings when the forecasted transaction occurs or, as appropriate, over the economic life of the hedged item. A contract designated as a hedge of an anticipated transaction that is no longer likely to occur is immediately recognized in earnings.

To qualify for hedge accounting, the item to be hedged must expose us to risk and the related hedging instrument must reduce the exposure and meet the formal hedging requirements of SFAS 133, Accounting for Derivative Instruments and Hedging Activities (as amended and interpreted). We formally designate the financial instrument as a hedge and document and assess the effectiveness of the hedge at its inception and thereafter on a quarterly basis. Any hedge ineffectiveness is immediately recognized in earnings.

We routinely review our outstanding financial instruments in light of current market conditions. If market conditions warrant, some financial instruments may be closed out in advance of their contractual settlement dates thus realizing income or loss depending on the specific hedging criteria. When this occurs, we may enter into a new financial instrument to reestablish the hedge to which the closed instrument relates.

Interest Rate Risk Hedging Program

Our interest rate exposure results from variable and fixed interest rate borrowings under various debt agreements. We manage a portion of our interest rate exposures by utilizing interest rate swaps and similar arrangements, which allow us to convert a portion of fixed rate debt into variable rate debt or a portion of variable rate debt into fixed rate debt.

Fair Value Hedges – Interest Rate Swaps. As summarized in the following table, we had five interest rate swap agreements outstanding at September 30, 2008 that were accounted for as fair value hedges.

Hedged Fixed Rate Debt	Number of Swaps	Period Covered by Swap	Termination Date of Swap	Fixed to Variable Rate (1)	Notional Value
Senior Notes C, 6.375% fixed rate, due Feb. 2013	1	Jan. 2004 to Feb. 2013	Feb. 2013	6.375% to 5.02%	$100.0 million
Senior Notes G, 5.60% fixed rate, due Oct. 2014	4	4th Qtr. 2004 to Oct. 2014	Oct. 2014	5.60% to 3.63%	$400.0 million

(1) The variable rate indicated is the all-in variable rate for the current settlement period.

The aggregate fair value of the five interest rate swaps at September 30, 2008 was an asset of $13.2 million, with an offsetting increase in the fair value of the underlying debt. There were eleven interest rate swaps outstanding at December 31, 2007 having an aggregate fair value of $14.8 million (an asset). Interest expense for the three months ended September 30, 2008 and 2007 includes a $1.8 million benefit and a $2.3 million loss, respectively, from interest rate swap agreements. For the nine months ended September 30, 2008 and 2007, interest expense reflects a benefit of $3.2 million and a loss of $6.9 million, respectively, from interest rate swap agreements.

The following table summarizes the termination of our interest rate swaps during 2008 (dollars in millions):

	Notional Value	Cash Gains (1)
Interest rate swap portfolio, December 31, 2007	$ 1,050.0	$ --
First quarter of 2008 terminations	(200.0)	6.3
Second quarter of 2008 terminations	(250.0)	12.0
Third quarter of 2008 terminations (2)	(100.0)	--
Interest rate swap portfolio, September 30, 2008	$ 500.0	$ 18.3

(1) Cash gains resulting from the termination, or monetization, of interest rate swaps will be amortized to earnings as a reduction to interest expense over the remaining life of the underlying debt.
(2) In early October 2008, one counterparty filed for bankruptcy. At September 30, 2008, the fair value of this interest rate swap was $3.4 million and this amount has been fully reserved. Hedge accounting for this swap has been discontinued.

Cash Flow Hedges – Interest Rate Swaps. Duncan Energy Partners had three floating-to-fixed interest rate swap agreements outstanding at September 30, 2008 that were accounted for as cash flow hedges.

Hedged Variable Rate Debt	Number of Swaps	Period Covered by Swap	Termination Date of Swap	Variable to Fixed Rate (1)	Notional Value
Duncan Energy Partners' Revolver, due Feb. 2011	3	Sep. 2007 to Sep. 2010	Sep. 2010	3.77% to 4.62%	$175.0 million

(1) Amounts receivable from or payable to the swap counterparties are settled every three months (the "settlement period").

We recognized losses of $0.8 million and $1.6 million from these swap agreements during the three and nine months ended September 30, 2008, respectively. The aggregate fair values of these interest rate swaps at September 30, 2008 and December 31, 2007 were liabilities of $4.3 million and $3.8 million, respectively. As cash flow hedges, any increase or decrease in fair value of the financial instrument (to the extent effective) would be recorded as other comprehensive income and amortized into earnings based on the settlement period being hedged. Over the next twelve months, we expect to reclassify $1.4 million of losses to earnings as an increase in interest expense.

Cash Flow Hedges – Treasury Locks. We occasionally use treasury lock financial instruments to hedge the underlying U.S. treasury rates related to our anticipated issuances of debt. Cash gains or losses on the termination, or monetization, of such instruments are amortized to earnings using the effective interest method over the estimated term of the underlying fixed-rate debt. Each of our treasury lock transactions were designated as a cash flow hedge. The following table summarizes changes in our treasury lock portfolio since December 31, 2007 (dollars in millions).

	Notional Value	Cash Losses (1)
Treasury lock portfolio, December 31, 2007	$ 600.0	$ --
First quarter of 2008 terminations	(350.0)	27.7
Second quarter of 2008 terminations	(250.0)	12.7
Treasury lock portfolio, September 30, 2008	$ --	$ 40.4

(1) Cash losses are included in net interest rate financial instrument losses in the Unaudited Condensed Statements of Consolidated Comprehensive Income.

We expect to reclassify $1.8 million of cumulative net gains from the monetization of treasury lock financial instruments to earnings (as a decrease in interest expense) over the next twelve months. This includes financial instruments that were settled in years prior to 2008.

Commodity Risk Hedging Program

The prices of natural gas, NGLs and certain petrochemical products are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control. In order to manage the price risks associated with such products, we may enter into commodity financial instruments.

The primary purpose of our commodity risk management activities is to reduce our exposure to price risks associated with (i) natural gas purchases, (ii) the value of NGL production and inventories, (iii) related firm commitments, (iv) fluctuations in transportation revenues where the underlying fees are based on natural gas index prices and (v) certain anticipated transactions involving either natural gas, NGLs or certain petrochemical products. From time to time, we inject natural gas into storage and may utilize hedging instruments to lock in the value of our inventory positions. The commodity financial instruments we utilize may be settled in cash or with another financial instrument.

We have segregated our commodity financial instruments portfolio between those financial instruments utilized in connection with our natural gas marketing activities and those used in connection with our NGL and petrochemical operations.

Natural gas marketing activities. At September 30, 2008 and December 31, 2007, the aggregate fair values of those financial instruments utilized in connection with our natural gas marketing activities was an asset of $0.8 million and a liability of $0.3 million, respectively. Our natural gas marketing business and its related use of financial instruments has increased since December 31, 2007. For additional information regarding our natural gas marketing activities, see Note 12. We currently utilize mark-to-market accounting for substantially all of the financial instruments utilized in connection with our natural gas marketing activities. The following table presents gains and losses recognized in earnings from this portion of the commodity financial instruments portfolio for the periods indicated (dollars in millions):

Three months ended September 30, 2008	Gains	$ 13.2
Three months ended September 30, 2007	Losses	$ (0.6)
Nine months ended September 30, 2008	Gains	$ 7.8
Nine months ended September 30, 2007	Losses	$ (0.1)

NGL and petrochemical operations. At September 30, 2008 and December 31, 2007, the aggregate fair values of financial instruments utilized in connection with our NGL and petrochemical operations were liabilities of $116.6 million and $19.0 million, respectively. The change in fair value between December 31, 2007 and September 30, 2008 is primarily due to a decrease in the price of natural gas and an increase in volumes hedged. Almost all of the financial instruments within this portion of the commodity financial instruments portfolio are accounted for as cash flow hedges, with a small number accounted for using mark-to-market accounting.

EPO has employed a program to economically hedge a portion of earnings from its natural gas processing business (a component of its NGL Pipelines & Services business segment). This program consists of (i) the forward sale of a portion of EPO's expected equity NGL production volumes at fixed prices through 2009 and (ii) the purchase (using commodity financial instruments) of the amount of natural gas expected to be consumed as plant thermal reduction ("PTR") in the production of such equity NGL volumes. The objective of this strategy is to hedge a level of gross margins (i.e., NGL sales revenues less actual costs for PTR and the gain or loss on the PTR hedge) associated with the forward sales contracts by fixing the cost of natural gas used for PTR, through the use of commodity financial instruments. At September 30, 2008, this hedging program had hedged future gross margins before plant operating expenses of $588.8 million for 28.8 million barrels of forecasted NGL forward sales transactions extending through 2009.

NGL forward sales contracts are not accounted for as financial instruments under SFAS 133; therefore, changes in the aggregate economic value of these sales contracts are not reflected in earnings and comprehensive income until the volumes are delivered to customers. On the other hand, the commodity financial instruments used to purchase the related quantities of PTR (i.e., "PTR hedges") are accounted for as cash flow hedges; therefore, changes in the aggregate fair value of the PTR hedges are presented in other comprehensive income.

Prior to actual settlement, if the market price of natural gas is less than the price stipulated in a PTR hedge, we recognize an unrealized loss in other comprehensive income for the excess of the natural gas price stated in the PTR hedge over the market price. To the extent that we realize such financial losses upon settlement of the instrument, the losses are added to the actual cost we have to pay for PTR (which would then be based on the lower market price). The end result of this relationship – financial gain/loss on the PTR hedges plus the market price of actual natural gas purchases at the time of consumption – is that our total cost of natural gas used for PTR approximates the amount we originally hedged under this program The converse is true if the price of natural gas decreases. During the third quarter of 2008, the price of natural gas decreased approximately 45% from June 30, 2008. As a result, we recognized unrealized losses in other comprehensive income with respect to the PTR hedges of $258.4 million during the third quarter of 2008. For the nine months ended September 30, 2008, we recognized unrealized losses in other comprehensive income of $126.0 million with respect to the PTR hedging program. Once the forecasted NGL forward sales transactions occur, any realized gains and losses on the cash flow hedges would be reclassified into earnings at that time.

The following table presents gains and losses recognized in earnings from this portion of the commodity financial instruments portfolio for the periods indicated (dollars in millions):

Three months ended September 30, 2008 (1)	Losses	$	(7.2)
Three months ended September 30, 2007	Losses	$	(10.1)
Nine months ended September 30, 2008 (2)	Gains	$	1.7
Nine months ended September 30, 2007	Losses	$	(11.9)

(1) Includes ineffectiveness of $5.6 million (an expense).
(2) Includes ineffectiveness of $2.8 million (an expense).

A significant number of the financial instruments in this portfolio hedge the purchase of physical natural gas. If natural gas prices fall below the price stipulated in such financial instruments, we recognize a liability for the difference; however, if prices partially or fully recover, this liability would be reduced or eliminated, as appropriate. Our restricted cash balance at September 30, 2008 was $183.2 million in order to meet commodity exchange deposit requirements and the negative change in the fair value of our commodity positions.

Foreign Currency Hedging Program

We are exposed to foreign currency exchange rate risk primarily through our Canadian NGL marketing subsidiary. As a result, we could be adversely affected by fluctuations in the foreign currency exchange rate between the U.S. dollar and the Canadian dollar. We attempt to hedge this risk using foreign exchange purchase contracts to fix the exchange rate. Mark-to-market accounting is utilized for these contracts, which typically have a duration of one month. For the nine months ended September 30, 2008, we recorded minimal gains from these financial instruments. No such amounts were recorded in the third quarter of 2008.

Adoption of SFAS 157 - Fair Value Measurements

On January 1, 2008, we adopted the provisions of SFAS 157 that apply to financial assets and liabilities. We will adopt the provisions of SFAS 157 that apply to nonfinancial assets and liabilities on January 1, 2009. SFAS 157 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at a specified measurement date.

Our fair value estimates are based on either (i) actual market data or (ii) assumptions that other market participants would use in pricing an asset or liability. These assumptions include estimates of risk. Recognized valuation techniques employ inputs such as product prices, operating costs, discount factors and business growth rates. These inputs may be either readily observable, corroborated by market data or generally unobservable. In developing our estimates of fair value, we endeavor to utilize the best information available and apply market-based data to the extent possible. Accordingly, we utilize valuation techniques (such as the market approach) that maximize the use of observable inputs and minimize the use of unobservable inputs.

SFAS 157 established a three-tier hierarchy that classifies fair value amounts recognized or disclosed in the financial statements based on the observability of inputs used to estimate such fair values. The hierarchy considers fair value amounts based on observable inputs (Levels 1 and 2) to be more reliable and predictable than those based primarily on unobservable inputs (Level 3). At each balance sheet reporting date, we categorize our financial assets and liabilities using this hierarchy. The characteristics of fair value amounts classified within each level of the SFAS 157 hierarchy are described as follows:

- Level 1 fair values are based on quoted prices, which are available in active markets for identical assets or liabilities as of the measurement date. Active markets are defined as those in which transactions for identical assets or liabilities occur in sufficient frequency so as to provide pricing information on an ongoing basis (e.g., the NYSE or NYMEX). Level 1 primarily consists of financial assets and liabilities such as exchange-traded financial instruments, publicly-traded equity securities and U.S. government treasury securities.

- Level 2 fair values are based on pricing inputs other than quoted prices in active markets (as reflected in Level 1 fair values) and are either directly or indirectly observable as of the measurement date. Level 2 fair values include instruments that are valued using financial models or other appropriate valuation methodologies. Such financial models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value of money, volatility factors for stocks and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are (i) observable in the marketplace throughout the full term of the instrument, (ii) can be derived from observable data or (iii) are validated by inputs other than quoted prices (e.g., interest rate and yield curves at commonly quoted intervals). Level 2 includes non-exchange-traded instruments such as over-the-counter forward contracts, options and repurchase agreements.

- Level 3 fair values are based on unobservable inputs. Unobservable inputs are used to measure fair value to the extent that observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date.

Unobservable inputs reflect the reporting entity's own ideas about the assumptions that market participants would use in pricing an asset or liability (including assumptions about risk). Unobservable inputs are based on the best information available in the circumstances, which might include the reporting entity's internally-developed data. The reporting entity must not ignore information about market participant assumptions that is reasonably available without undue cost and effort. Level 3 inputs are typically used in connection with internally developed valuation methodologies where management makes its best estimate of an instrument's fair value. Level 3 generally includes specialized or unique financial instruments that are tailored to meet a customer's specific needs.

The following table sets forth, by level within the fair value hierarchy, our financial assets and liabilities measured on a recurring basis at September 30, 2008. These financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value assets and liabilities and their placement within the fair value hierarchy levels. At September 30, 2008 there were no Level 1 financial assets or liabilities.

	Level 2	Level 3	Total
Financial assets:			
Commodity financial instruments	$ 15,320	$ 18,445	$ 33,765
Interest rate financial instruments	13,151	--	13,151
Total	$ 28,471	$ 18,445	$ 46,916
Financial liabilities:			
Commodity financial instruments	$ 149,577	$ --	$ 149,577
Interest rate financial instruments	4,301	--	4,301
Total	$ 153,878	$ --	$ 153,878

Fair values associated with our interest rate, commodity and foreign currency financial instrument portfolios were developed using available market information and appropriate valuation techniques in accordance with SFAS 157.

The following table sets forth a reconciliation of changes in the fair value of our Level 3 financial assets and liabilities for the periods indicated:

Balance, January 1, 2008	$ (4,660)
Total gains (losses) included in:	
Net income (1)	(2,254)
Other comprehensive income	2,419
Purchases, issuances, settlements	1,861
Balance, March 31, 2008	(2,634)
Total gains (losses) included in:	
Net income (1)	322
Other comprehensive income	(2,428)
Purchases, issuances, settlements	71
Balance, June 30, 2008	(4,669)
Total gains (losses) included in:	
Net income (1)	(2,190)
Other comprehensive loss	23,114
Purchases, issuances, settlements	2,190
Balance, September 30, 2008	$ 18,445

(1) Net income includes commodity financial instrument losses of $2.2 million and $4.1 million, respectively, recorded in revenue for the three and nine months ended September 30, 2008. There were no unrealized gains included in these amounts.

Note 5. Inventories

Our inventory amounts were as follows at the dates indicated:

	September 30, 2008	December 31, 2007
Working inventory (1)	$ 602,909	$ 342,589
Forward-sales inventory (2)	50,874	11,693
Total inventory	$ 653,783	$ 354,282

(1) Working inventory is comprised of inventories of natural gas, NGLs and certain petrochemical products that are either available-for-sale or used in the provision for services.
(2) Forward sales inventory consists of segregated NGL and natural gas volumes dedicated to the fulfillment of forward-sales contracts.

Our inventory values reflect payments for product purchases, freight charges associated with such purchase volumes, terminal and storage fees, vessel inspection costs, demurrage charges and other related costs. We value our inventories at the lower of average cost or market.

Operating costs and expenses, as presented on our Unaudited Condensed Statements of Consolidated Operations, include cost of sales amounts related to the sale of inventories. Our cost of sales amounts were $5.47 billion and $3.53 billion for the three months ended September 30, 2008 and 2007, respectively. For the nine months ended September 30, 2008 and 2007, our cost of sales were $15.88 billion and $9.89 billion, respectively.

Due to fluctuating commodity prices in the NGL, natural gas and petrochemical industry, we recognize lower of cost or market ("LCM") adjustments when the carrying value of our inventories exceed their net realizable value. These non-cash charges are a component of cost of sales in the period they are recognized. For the three months ended September 30, 2008 and 2007, we recognized LCM adjustments of approximately $36.4 million and $0.2 million, respectively. We recognized LCM adjustments of $41.3 million and $13.3 million for the nine months ended September 30, 2008 and 2007, respectively.

Note 6. Property, Plant and Equipment

Our property, plant and equipment values and related accumulated depreciation balances were as follows at the dates indicated:

	Estimated Useful Life in Years	September 30, 2008	December 31, 2007
Plants and pipelines (1)	3-35(5)	$ 12,019,063	$ 10,884,819
Underground and other storage facilities (2)	5-35(6)	784,808	720,795
Platforms and facilities (3)	20-31	634,809	637,812
Transportation equipment (4)	3-10	35,865	32,627
Land		50,560	48,172
Construction in progress		1,417,947	1,173,988
Total		14,943,052	13,498,213
Less accumulated depreciation		2,249,433	1,910,949
Property, plant and equipment, net		$ 12,693,619	$ 11,587,264

(1) Plants and pipelines include processing plants; NGL, petrochemical, oil and natural gas pipelines; terminal loading and unloading facilities; office furniture and equipment; buildings; laboratory and shop equipment; and related assets.
(2) Underground and other storage facilities include underground product storage caverns; storage tanks; water wells; and related assets.
(3) Platforms and facilities include offshore platforms and related facilities and other associated assets.
(4) Transportation equipment includes vehicles and similar assets used in our operations.
(5) In general, the estimated useful lives of major components of this category are as follows: processing plants, 20-35 years; pipelines, 18-35 years (with some equipment at 5 years); terminal facilities, 10-35 years; office furniture and equipment, 3-20 years; buildings, 20-35 years; and laboratory and shop equipment, 5-35 years.
(6) In general, the estimated useful lives of major components of this category are as follows: underground storage facilities, 20-35 years (with some components at 5 years); storage tanks, 10-35 years; and water wells, 25-35 years (with some components at 5 years).

The following table summarizes our depreciation expense and capitalized interest amounts for the periods indicated:

	For the Three Months Ended September 30, 2008	For the Three Months Ended September 30, 2007	For the Nine Months Ended September 30, 2008	For the Nine Months Ended September 30, 2007
Depreciation expense (1)	$ 115,517	$ 108,692	$ 339,332	$ 302,758
Capitalized interest (2)	$ 17,284	$ 18,656	$ 53,019	$ 59,795

(1) Depreciation expense is a component of costs and expenses as presented in our Unaudited Condensed Statements of Consolidated Operations.
(2) Capitalized interest increases the carrying value of the associated asset and reduces interest expense during the period it is recorded.

We reviewed assumptions underlying the estimated remaining useful lives of certain of our assets during the first quarter of 2008. As a result of our review, effective January 1, 2008, we revised the remaining useful lives of these assets, most notably the assets that constitute our Texas Intrastate System. This revision increased the remaining useful life of such assets to incorporate recent data showing that proved natural gas reserves supporting throughput and processing volumes for these assets have changed since our original determination made in September 2004. These revisions will prospectively reduce our depreciation expense on assets having carrying values totaling $2.72 billion as of January 1, 2008. On average, we extended the life of these assets by 3.1 years. As a result of this change in estimate, depreciation expense included in operating income and net income for the three and nine months ended September 30, 2008 decreased by approximately $5.0 million and $15.0 million, respectively, which increased our earnings per unit by $0.01 and $0.03, respectively, from what it would have been absent the change.

Asset retirement obligations

Asset retirement obligations ("AROs") are legal obligations associated with the retirement of a tangible long-lived asset that results from its acquisition, construction, development or normal operation or a combination of these factors. The following table summarizes amounts recognized in connection with AROs since December 31, 2007:

ARO liability balance, December 31, 2007	$ 40,614
Liabilities incurred	810
Liabilities settled	(7,154)
Revisions in estimated cash flows	2,411
Accretion expense	1,660
ARO liability balance, September 30, 2008	$ 38,341

Property, plant and equipment at September 30, 2008 and December 31, 2007 includes $8.8 million and $10.6 million, respectively, of asset retirement costs capitalized as an increase in the associated long-lived asset.

Note 7. Investments in and Advances to Unconsolidated Affiliates

We own interests in a number of related businesses that are accounted for using the equity method of accounting. Our investments in and advances to unconsolidated affiliates are grouped according to the business segment to which they relate. See Note 12 for a general discussion of our business segments. The following table presents our investments in and advances to unconsolidated affiliates at the dates indicated.

	Ownership Percentage at September 30, 2008	September 30, 2008	December 31, 2007
NGL Pipelines & Services:			
Venice Energy Service Company, L.L.C. ("VESCO")	13.1%	$ 38,542	$ 40,129
K/D/S Promix, L.L.C. ("Promix")	50.0%	47,291	51,537
Baton Rouge Fractionators LLC ("BRF")	32.2%	25,410	25,423
Onshore Natural Gas Pipelines & Services:			
Jonah Gas Gathering Company ("Jonah")	19.4%	278,736	235,837
Evangeline (2)	49.5%	4,494	3,490
White River Hub, LLC ("White River Hub") (1)	50.0%	19,654	--
Offshore Pipelines & Services:			
Poseidon Oil Pipeline Company, L.L.C. ("Poseidon")	36.0%	59,364	58,423
Cameron Highway Oil Pipeline Company ("Cameron Highway")	50.0%	260,713	256,588
Deepwater Gateway, L.L.C. ("Deepwater Gateway")	50.0%	109,263	111,221
Neptune Pipeline Company, L.L.C. ("Neptune")	25.7%	52,278	55,468
Nemo Gathering Company, LLC ("Nemo")	33.9%	784	2,888
Texas Offshore Port System ("TOPS")	33.3%	2,355	--
Petrochemical Services:			
Baton Rouge Propylene Concentrator LLC ("BRPC")	30.0%	14,255	13,282
La Porte (3)	50.0%	4,054	4,053
Total		$ 917,193	$ 858,339

(1) In February 2008, we acquired a 50.0% ownership interest in White River Hub.
(2) Refers to our ownership interests in Evangeline Gas Pipeline Company, L.P. and Evangeline Gas Corp., collectively.
(3) Refers to our ownership interests in La Porte Pipeline Company, L.P. and La Porte GP, LLC, collectively.

On occasion, the price we pay to acquire a non-controlling ownership interest in a company exceeds the underlying book value of the net assets we acquire. Such excess cost amounts are included within the carrying values of our investments in and advances to unconsolidated affiliates. At September 30, 2008 and December 31, 2007, our investments in Promix, La Porte, Neptune, Poseidon, Cameron Highway and Jonah included excess cost amounts totaling $44.1 million and $43.8 million, respectively.

These amounts are attributable to the excess of the fair value of each entity's tangible assets over their respective book carrying values at the time we acquired an interest in each entity. Amortization of such excess cost amounts was $0.5 million during each of the three months ended September 30, 2008 and 2007. For each of the nine months ended September 30, 2008 and 2007, amortization of such amounts was $1.5 million.

The following table presents our equity in earnings of unconsolidated affiliates by business segment for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2008	2007	2008	2007
NGL Pipelines & Services	$ 3,009	$ 2,684	$ 2,288	$ 4,364
Onshore Natural Gas Pipelines & Services	5,598	2,351	16,883	4,592
Offshore Pipelines & Services	5,987	8,557	27,914	3,786
Petrochemical Services	282	368	952	1,186
Total	$ 14,876	$ 13,960	$ 48,037	$ 13,928

On a quarterly basis, we monitor the underlying business fundamentals of our investments in unconsolidated affiliates and test such investments for impairment when impairment indicators are present. As a result of our reviews for the third quarter of 2008, no impairment charges were required. We have the intent and ability to hold these investments, which are integral to our operations.

Summarized Financial Information of Unconsolidated Affiliates

The following tables present unaudited income statement data for our current unconsolidated affiliates, aggregated by business segment, for the periods indicated (on a 100% basis).

	Summarized Income Statement Information for the Three Months Ended					
	September 30, 2008			September 30, 2007		
	Revenues	Operating Income	Net Income	Revenues	Operating Income	Net Income
NGL Pipelines & Services	$ 75,108	$ 9,742	$ 6,788	$ 49,579	$ 15,435	$ 16,118
Onshore Natural Gas Pipelines & Services	188,887	28,953	27,911	126,042	24,659	23,447
Offshore Pipelines & Services	31,926	12,812	11,976	39,331	21,363	19,974
Petrochemical Services	5,596	1,105	1,111	4,894	1,480	1,492

	Summarized Income Statement Information for the Nine Months Ended					
	September 30, 2008			September 30, 2007		
	Revenues	Operating Income	Net Income	Revenues	Operating Income	Net Income
NGL Pipelines & Services	$ 217,822	$ 17,749	$ 15,049	$ 150,367	$ 17,916	$ 19,873
Onshore Natural Gas Pipelines & Services	492,455	88,677	85,295	360,072	71,472	67,862
Offshore Pipelines & Services	115,018	62,363	57,202	116,957	65,227	34,204
Petrochemical Services	16,592	3,891	3,907	15,416	4,770	4,832

White River Hub Joint Venture

In February 2008, we formed a joint venture, White River Hub, with a wholly-owned subsidiary of Questar Corporation to design, construct, own and operate a natural gas hub located in the vicinity of Meeker, Colorado. White River Hub will construct a FERC-regulated interstate natural gas transmission system for the purpose of providing natural gas transportation and hub services to its customers. The newly constructed natural gas hub will connect six interstate natural gas pipelines in northwest Colorado and have a capacity in excess of 2.0 billion cubic feet per day ("Bcf/d"). This project is expected to be completed during the fourth quarter of 2008 and our share of the estimated construction costs is $22.1 million.

Texas Offshore Port System Joint Venture

In August 2008, we, together with TEPPCO and Oiltanking Holding Americas, Inc. ("Oiltanking"), announced the formation of a joint venture to design, construct, operate and own a Texas offshore crude oil port and related pipeline and storage infrastructure that would facilitate delivery of waterborne crude oil to refining centers located along the upper Texas Gulf Coast. Demand for such projects is being driven by planned and expected refinery expansions along the Gulf Coast, expected increases in shipping traffic and operating limitations of regional ship channels.

The joint venture's primary project, referred to as "TOPS," includes (i) an offshore port (which will be located approximately 36 miles from Freeport, Texas), (ii) an onshore storage facility with approximately 3.9 million barrels of crude oil storage capacity, and (iii) an 85-mile crude oil pipeline system having a transportation capacity of up to 1.8 million barrels per day, that will extend from the offshore port to a Texas City, Texas storage facility. TOPS is expected to begin service as early as the fourth quarter of 2010. The joint venture's second and complementary project, referred to as the Port Arthur Crude Oil Express (or "PACE") will transport crude oil from Texas City, including crude oil from TOPS, and will consist of a 75-mile pipeline and 1.2 million barrels of crude oil storage capacity in the Port Arthur, Texas area. PACE is expected to begin service as early as the third quarter of 2010. Development of the TOPS and PACE projects is supported by long-term contracts with affiliates of Motiva Enterprises LLC and Exxon Mobil Corporation, which have committed a combined 725,000 barrels per day of crude oil to the projects.

We, TEPPCO and Oiltanking each own, through our respective subsidiaries, a one-third interest in the joint venture. The aggregate cost of the TOPS and PACE projects is expected to be approximately $1.8 billion (excluding capitalized interest), with the majority of such capital expenditures occurring in 2009 and 2010. We and TEPPCO have each guaranteed up to approximately $700.0 million of the capital contribution obligations of our respective subsidiary partners in the joint venture. As of September 30, 2008, our investment in TOPS was $2.4 million.

Note 8. Business Combinations

Acquisition of Remaining Interest in Dixie

In August 2008, we acquired the remaining 25.8% ownership interest in Dixie for $57.1 million. As a result of this transaction, we own 100% of Dixie, which owns a 1,300-mile pipeline system that delivers NGLs (primarily propane and other chemical feedstocks) to customers along the U.S. Gulf Coast and southeastern United States.

Purchase Price Allocations

We accounted for business combinations completed during the nine months ended September 30, 2008 using the purchase method of accounting and, accordingly, such costs have been allocated to assets acquired and liabilities assumed based on estimated preliminary fair values. Such preliminary values have been developed using recognized business valuation techniques and are subject to change pending a final valuation analysis. We expect to finalize the purchase price allocations for these transactions during 2008.

	Dixie	South Monco (1)	Total
Assets acquired in business combination:			
Current assets	$ --	$ 35	$ 35
Property, plant and equipment, net	24,114	(12,781)	11,333
Intangible assets	--	12,747	12,747
Total assets acquired	24,114	1	24,115
Liabilities assumed in business combination:			
Minority interest	7,631	--	7,631
Total liabilities assumed	7,631	--	7,631
Total assets acquired plus liabilities assumed	31,745	1	31,746
Total cash used for business combinations	57,089	1	57,090
Goodwill	$ 25,344	$ --	$ 25,344

(1) Represents non-cash reclassification adjustments to December 2007 preliminary fair value estimates for assets acquired in the South Monco natural gas pipeline acquisition.

Note 9. Intangible Assets and Goodwill

Identifiable Intangible Assets

The following table summarizes our intangible assets at the dates indicated:

	September 30, 2008			December 31, 2007		
	Gross Value	Accum. Amort.	Carrying Value	Gross Value	Accum. Amort.	Carrying Value
NGL Pipelines & Services	$ 523,401	$ (174,863)	$ 348,538	$ 520,025	$ (146,954)	$ 373,071
Onshore Natural Gas Pipelines & Services	476,298	(133,962)	342,336	463,551	(109,399)	354,152
Offshore Pipelines & Services	207,012	(86,797)	120,215	207,012	(73,954)	133,058
Petrochemical Services	67,906	(12,682)	55,224	67,906	(11,187)	56,719
Total	$ 1,274,617	$ (408,304)	$ 866,313	$ 1,258,494	$ (341,494)	$ 917,000

The following table presents the amortization expense of our intangible assets by segment for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2008	2007	2008	2007
NGL Pipelines & Services	$ 9,203	$ 8,869	$ 27,908	$ 26,912
Onshore Natural Gas Pipelines & Services	8,014	7,946	24,564	24,154
Offshore Pipelines & Services	4,135	4,745	12,843	14,733
Petrochemical Services	499	499	1,495	1,495
Total	$ 21,851	$ 22,059	$ 66,810	$ 67,294

For the remainder of 2008, amortization expense associated with our intangible assets is currently estimated at $21.5 million.

Goodwill

The following table summarizes our goodwill amounts by segment at the dates indicated:

	September 30, 2008	December 31, 2007
NGL Pipelines & Services (1)	$ 179,050	$ 153,706
Onshore Natural Gas Pipelines & Services	282,121	282,121
Offshore Pipelines & Services	82,135	82,135
Petrochemical Services	73,690	73,690
Total	$ 616,996	$ 591,652

(1) See Note 8 for information regarding our recent acquisition of the remaining ownership interests in Dixie, which resulted in additional goodwill of $25.3 million.

Note 10. Debt Obligations

Our consolidated debt obligations consisted of the following at the dates indicated:

	September 30, 2008	December 31, 2007
EPO senior debt obligations:		
Multi-Year Revolving Credit Facility, variable rate, due November 2012	$ 1,150,701	$ 725,000
Pascagoula MBFC Loan, 8.70% fixed-rate, due March 2010	54,000	54,000
Senior Notes B, 7.50% fixed-rate, due February 2011	450,000	450,000
Senior Notes C, 6.375% fixed-rate, due February 2013	350,000	350,000
Senior Notes D, 6.875% fixed-rate, due March 2033	500,000	500,000
Senior Notes F, 4.625% fixed-rate, due October 2009	500,000	500,000
Senior Notes G, 5.60% fixed-rate, due October 2014	650,000	650,000
Senior Notes H, 6.65% fixed-rate, due October 2034	350,000	350,000
Senior Notes I, 5.00% fixed-rate, due March 2015	250,000	250,000
Senior Notes J, 5.75% fixed-rate, due March 2035	250,000	250,000
Senior Notes K, 4.950% fixed-rate, due June 2010	500,000	500,000
Senior Notes L, 6.30% fixed-rate, due September 2017	800,000	800,000
Senior Notes M, 5.65% fixed-rate, due April 2013	400,000	--
Senior Notes N, 6.50% fixed-rate, due January 2019	700,000	--
Petal GO Zone Bonds, variable rate, due August 2037	57,500	57,500
Duncan Energy Partners' debt obligation:		
$300 Million Revolving Credit Facility, variable rate, due February 2011	212,000	200,000
Dixie Revolving Credit Facility, variable rate, due June 2010	10,000	10,000
Total principal amount of senior debt obligations	7,184,201	5,646,500
EPO Junior Subordinated Notes A, fixed/variable rates, due August 2066	550,000	550,000
EPO Junior Subordinated Notes B, fixed/variable rates, due January 2068	700,000	700,000
Total principal amount of senior and junior debt obligations	8,434,201	6,896,500
Other, non-principal amounts:		
Change in fair value of debt-related financial instruments (see Note 4)	20,096	14,839
Unamortized discounts, net of premiums	(7,405)	(5,194)
Unamortized deferred net gains related to terminated interest rate swaps (see Note 4)	11,303	--
Total other, non-principal amounts	23,994	9,645
Long-term debt	$ 8,458,195	$ 6,906,145
Standby letters of credit outstanding	$ 61,100	$ 1,100

Enterprise Products Partners L.P. acts as guarantor of the consolidated debt obligations of EPO with the exception of Dixie's revolving credit facility and Duncan Energy Partners' revolving credit facility. If EPO were to default on any of its guaranteed debt, Enterprise Products Partners L.P. would be responsible for full repayment of that obligation.

We consolidate the debt of Dixie and Duncan Energy Partners; however, neither Enterprise Products Partners L.P. nor EPO has the obligation to make interest or debt payments with respect to such obligations.

With respect to debt agreements existing at September 30, 2008, there have been no significant changes in the terms of our consolidated debt obligations since December 31, 2007.

Letters of credit. During the third quarter of 2008, a $60.0 million letter of credit was issued under EPO's Multi-Year Revolving Credit Facility to support our NYMEX margin requirements for natural gas financial instruments that are part of an economic hedge related to our natural gas processing business. In October 2008, EPO entered into a $100.0 million letter of credit facility. EPO issued a $70.0 million letter of credit under this new facility that replaced the letter of credit issued under its Multi-Year Revolving Credit Facility which was outstanding at September 30, 2008.

Senior Notes M and N. In April 2008, EPO sold $400.0 million in principal amount of 5-year senior unsecured notes ("Senior Notes M") and $700.0 million in principal amount of 10-year senior unsecured notes ("Senior Notes N") under its universal registration statement. Senior Notes M were issued at 99.906% of their principal amount, have a fixed interest rate of 5.65% and mature in April 2013. Senior Notes N were issued at 99.866% of their principal amount, have a fixed interest rate of 6.50% and mature in January 2019.

Senior Notes M pay interest semi-annually in arrears on April 1 and October 1 of each year. Senior Notes N pay interest semi-annually in arrears on January 31 and July 31 of each year. Net proceeds from the issuance of Senior Notes M and N were used to temporarily reduce indebtedness outstanding under the EPO Multi-Year Revolving Credit Facility.

Senior Notes M and N rank equal with EPO's existing and future unsecured and unsubordinated indebtedness. They are senior to any existing and future subordinated indebtedness of EPO. Senior Notes M and N are subject to make-whole redemption rights and were issued under indentures containing certain covenants, which generally restrict EPO's ability, with certain exceptions, to incur debt secured by liens and engage in sale and leaseback transactions.

Covenants

We are in compliance with the covenants of our consolidated debt agreements at September 30, 2008 and December 31, 2007.

Information regarding variable interest rates paid

The following table presents the weighted-average interest rate paid on our consolidated variable-rate debt obligations during the nine months ended September 30, 2008.

	Weighted-average interest rate paid
EPO's Multi-Year Revolving Credit Facility	3.62%
Duncan Energy Partners' Revolving Credit Facility	4.15%
Dixie Revolving Credit Facility	3.25%
Petal GO Zone Bonds	2.27%

Consolidated debt maturity table

The following table presents the scheduled maturities of principal amounts of our consolidated debt obligations for the next five years and in total thereafter.

2008	$ --
2009	500,000
2010	564,000
2011	662,000
2012	1,150,701
Thereafter	5,557,500
Total scheduled principal payments	$ 8,434,201

Debt Obligations of Unconsolidated Affiliates

We have two unconsolidated affiliates with long-term debt obligations. The following table shows (i) our ownership interest in each entity at September 30, 2008, (ii) total debt of each unconsolidated affiliate at September 30, 2008 (on a 100% basis to the affiliate) and (iii) the corresponding scheduled maturities of such debt.

	Our Ownership Interest	Total	Scheduled Maturities of Debt 2008	2009	2010	2011	2012	After 2012
Poseidon	36.0%	$ 109,000	$ --	$ --	$ --	$ 109,000	$ --	$ --
Evangeline	49.5%	20,650	5,000	5,000	3,150	7,500	--	--
Total		$ 129,650	$ 5,000	$ 5,000	$ 3,150	$ 116,500	$ --	$ --

The credit agreements of our unconsolidated affiliates contain various affirmative and negative covenants, including financial covenants. These businesses were in compliance with such covenants at September 30, 2008. The credit agreements of our unconsolidated affiliates restrict their ability to pay cash dividends if a default or an event of default (as defined in each credit agreement) has occurred and is continuing at the time such dividend is scheduled to be paid.

There have been no significant changes in the terms of the debt obligations of our unconsolidated affiliates since those reported in our Annual Report on Form 10-K for the year ended December 31, 2007.

Note 11. Partners' Equity and Distributions

Our common units represent limited partner interests, which give the holders thereof the right to participate in distributions and to exercise the other rights or privileges available to them under our Fifth Amended and Restated Agreement of Limited Partnership (together with all amendments thereto, the "Partnership Agreement"). We are managed by our general partner, EPGP.

In accordance with the Partnership Agreement, capital accounts are maintained for our general partner and limited partners. The capital account provisions of our Partnership Agreement incorporate principles established for U.S. Federal income tax purposes and are not comparable to the equity accounts reflected under GAAP in our condensed consolidated financial statements.

Our Partnership Agreement sets forth the calculation to be used in determining the amount and priority of cash distributions that our limited partners and general partner will receive. The Partnership Agreement also contains provisions for the allocation of net earnings and losses to our limited partners and general partner. For purposes of maintaining partner capital accounts, the Partnership Agreement specifies that items of income and loss shall be allocated among the partners in accordance with their respective percentage interests. Normal income and loss allocations according to percentage interests are done only after giving effect to priority earnings allocations in an amount equal to incentive cash distributions allocated to our general partner.

Equity Offerings and Registration Statements

In general, the Partnership Agreement authorizes us to issue an unlimited number of additional limited partner interests and other equity securities for such consideration and on such terms and conditions as may be established by EPGP in its sole discretion (subject, under certain circumstances, to the approval of our unitholders).

We have a universal shelf registration statement on file with the SEC registering the issuance of an unlimited amount of equity and debt securities. In April 2008, EPO sold $1.10 billion in principal amount of senior notes under our universal shelf registration statement. For additional information regarding this debt offering, see Note 10.

We also have on file with the SEC a registration statement authorizing the issuance of up to 25,000,000 common units in connection with our distribution reinvestment plan ("DRIP"). The DRIP provides unitholders of record and beneficial owners of our common units a voluntary means by which they can increase the number of common units they own by reinvesting the quarterly cash distributions they would otherwise receive into the purchase of additional common units of our partnership. An aggregate of 1,895,776 of our common units were issued in connection with the DRIP and the employee unit purchase plan ("EUPP") during the nine months ended September 30, 2008. The issuance of these units generated $56.5 million in net proceeds that we used for general partnership purposes. In November 2008, affiliates of EPCO, including Enterprise GP Holdings, expect to reinvest $67.0 million of their distributions through the DRIP.

The following table reflects the number of common units issued and the net proceeds received from other common unit offerings completed during the nine months ended September 30, 2008:

	Net Proceeds from Sale of Common Units			
	Number of Common Units Issued	Contributed by Limited Partners	Contributed by General Partner	Total Net Proceeds
February DRIP and EUPP	587,610	$ 17,651	$ 360	$ 18,011
May DRIP and EUPP	631,950	19,025	389	19,414
August DRIP and EUPP	676,216	18,687	381	19,068
Total 2008	1,895,776	$ 55,363	$ 1,130	$ 56,493

Summary of Changes in Outstanding Units

The following table summarizes changes in our outstanding units since December 31, 2007:

	Common Units	Restricted Common Units	Treasury Units
Balance, December 31, 2007	433,608,763	1,688,540	--
Common units issued in connection with DRIP and EUPP	1,895,776	--	--
Common units issued in connection with unit-based awards	21,905	--	--
Restricted units issued	--	750,900	--
Conversion of restricted units to common units	115,150	(115,150)	--
Acquisition of treasury units	(30,918)	--	30,918
Cancellation of treasury units	--	--	(30,918)
Forfeiture of restricted units	--	(84,677)	--
Balance, September 30, 2008	435,610,676	2,239,613	--

During the nine months ended September 30, 2008, 115,150 restricted unit awards vested and were converted to common units. Of this amount, 30,918 were sold back to us by employees to cover related withholding tax requirements. The total cost of these treasury units was approximately $795 thousand, of which $779 thousand was allocated to limited partners and the remainder to our general partner. Immediately upon acquisition, we cancelled such treasury units.

Summary of Changes in Limited Partners' Equity

The following table details the changes in limited partners' equity since December 31, 2007:

	Common Units	Restricted Common Units	Total
Balance, December 31, 2007	$ 5,976,947	$ 15,948	$ 5,992,895
Net income	617,761	2,733	620,494
Operating leases paid by EPCO	1,541	7	1,548
Cash distributions to partners	(661,137)	(2,809)	(663,946)
Unit option reimbursements to EPCO	(550)	--	(550)
Non-cash distributions	(5,006)	--	(5,006)
Acquisition of treasury units, limited partner share	--	(779)	(779)
Net proceeds from issuance of common units	55,363	--	55,363
Proceeds from exercise of unit options	680	--	680
Amortization of unit-based awards	4,862	8,769	13,631
Balance, September 30, 2008	$ 5,990,461	$ 23,869	$ 6,014,330

Distributions to Partners

The percentage interest of EPGP in our quarterly cash distributions is increased after certain specified target levels of quarterly distribution rates are met. At current distribution rates, we are in the highest tier of such incentive targets. EPGP's quarterly incentive distribution thresholds are as follows:

- 2% of quarterly cash distributions up to $0.253 per unit;
- 15% of quarterly cash distributions from $0.253 per unit up to $0.3085 per unit; and
- 25% of quarterly cash distributions that exceed $0.3085 per unit.

We paid incentive distributions of $32.0 million and $27.4 million to EPGP during the three months ended September 30, 2008 and 2007, respectively. During the nine months ended September 30, 2008 and 2007, we paid incentive distributions of $92.8 million and $79.0 million, respectively, to EPGP.

We paid aggregate distributions to our unitholders and general partner of $770.3 million during the nine months ended September 30, 2008. These distributions pertained to the nine month period ended June 30, 2008 (i.e., the fourth quarter of 2007, and first and second quarters of 2008). On November 12, 2008, we will pay a quarterly cash distribution of $0.5225 per unit with respect to the third quarter of 2008, to unitholders of record at the close of business on October 31, 2008.

Accumulated Other Comprehensive Income (Loss)

Accumulated other comprehensive income (loss) primarily includes the effective portion of the gain or loss on financial instruments designated and qualified as a cash flow hedge, foreign currency adjustments and Dixie's minimum pension liability adjustments. Amounts accumulated in other comprehensive income (loss) from cash flow hedges are reclassified into earnings in the same period(s) in which the hedged forecasted transactions (such as a forecasted forward sale of NGLs) affect earnings. If it becomes probable that the forecasted transaction will not occur, the net gain or loss in accumulated other comprehensive income (loss) must be immediately reclassified.

The following table presents the components of accumulated other comprehensive income (loss) at the dates indicated:

	September 30, 2008	December 31, 2007
Commodity financial instruments – cash flow hedges (1)	$ (129,913)	$ (21,619)
Interest rate financial instruments – cash flow hedges (1)	9,714	34,980
Foreign currency cash flow hedges (1)	--	1,308
Foreign currency translation adjustment (2)	1,652	1,200
Pension and postretirement benefit plans (3)	324	588
Total accumulated other comprehensive income (loss)	$ (118,223)	$ 16,457

(1) See Note 4 for additional information regarding financial instruments. The negative change in fair value of our commodity financial instruments between December 31, 2007 and September 30, 2008 is primarily due to a significant decrease in natural gas prices during the third quarter of 2008.
(2) Relates to transactions of our Canadian NGL marketing subsidiary.
(3) See Note 2 for additional information regarding Dixie's pension and postretirement benefit plans.

Note 12. Business Segments

We have four reportable business segments: NGL Pipelines & Services, Onshore Natural Gas Pipelines & Services, Offshore Pipelines & Services and Petrochemical Services. Our business segments are generally organized and managed according to the type of services rendered (or technologies employed) and products produced and/or sold.

We evaluate segment performance based on the non-GAAP financial measure of gross operating margin. Gross operating margin (either in total or by individual segment) is an important performance measure of the core profitability of our operations. This measure forms the basis of our internal financial reporting and is used by senior management in deciding how to allocate capital resources among business segments. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating segment results. The GAAP financial measure most directly comparable to total segment gross operating margin is operating income. Our non-GAAP financial measure of total segment gross operating margin should not be considered an alternative to GAAP operating income.

We define total segment gross operating margin as consolidated operating income before: (i) depreciation, amortization and accretion expense; (ii) operating lease expenses for which we do not have the payment obligation; (iii) gains and losses from asset sales and related transactions; and (iv) general and administrative costs. Gross operating margin is exclusive of other income and expense transactions, provision for income taxes, minority interest, extraordinary charges and the cumulative effect of changes in accounting principle. Gross operating margin by segment is calculated by subtracting segment operating costs and expenses (net of the adjustments noted above) from segment revenues, with both segment totals before the elimination of intersegment and intrasegment transactions.

Segment revenues include intersegment and intrasegment transactions, which are generally based on transactions made at market-related rates. Our consolidated revenues reflect the elimination of intercompany (both intersegment and intrasegment) transactions.

We include equity earnings from unconsolidated affiliates in our measurement of segment gross operating margin and operating income. Our equity investments with industry partners are a vital component of our business strategy. They are a means by which we conduct our operations to align our interests with those of our customers and/or suppliers. This method of operation enables us to achieve favorable economies of scale relative to the level of investment and business risk assumed versus what we could accomplish on a stand-alone basis. Many of these businesses perform supporting or complementary roles to our other business operations.

Our integrated midstream energy asset system (including the midstream energy assets of our equity method investees) provides services to producers and consumers of natural gas, NGLs, crude oil and certain petrochemicals. In general, hydrocarbons enter our asset system in a number of ways, such as an offshore natural gas or crude oil pipeline, an offshore platform, a natural gas processing plant, an onshore natural gas gathering pipeline, an NGL fractionator, an NGL storage facility, or an NGL transportation or distribution pipeline.

Many of our equity investees are included within our integrated midstream asset system. For example, we have ownership interests in several offshore natural gas and crude oil pipelines. Other examples include our use of the Promix NGL fractionator to process mixed NGLs extracted by our gas plants. The fractionated NGLs we receive from Promix can then be sold in our NGL marketing activities. Given the integral nature of our equity method investees to our operations, we believe the presentation of earnings from such investees as a component of gross operating margin and operating income is meaningful and appropriate.

Historically, substantially all of our consolidated revenues were earned in the United States and derived from a wide customer base. The majority of our plant-based operations are located in Texas, Louisiana, Mississippi, New Mexico, Colorado and Wyoming. Our natural gas, NGL and crude oil pipelines are located in a number of regions of the United States including (i) the Gulf of Mexico offshore Texas and Louisiana; (ii) the south and southeastern United States (primarily in Texas, Louisiana, Mississippi and Alabama); and (iii) certain regions of the central and western United States, including the Rocky Mountains. Our marketing activities are headquartered in Houston, Texas and serve customers in a number of regions of the United States including the Gulf Coast, West Coast and Mid-Continent areas.

Consolidated property, plant and equipment and investments in and advances to unconsolidated affiliates are assigned to each segment on the basis of each asset's or investment's principal operations. The principal reconciling difference between consolidated property, plant and equipment and the total value of segment assets is construction-in-progress. Segment assets represent the net book carrying value of facilities and other assets that contribute to gross operating margin of that particular segment. Since assets under construction generally do not contribute to segment gross operating margin, such assets are excluded from segment asset totals until they are placed in service. Consolidated intangible assets and goodwill are assigned to each segment based on the classification of the assets to which they relate.

We consolidate the financial statements of Duncan Energy Partners with those of our own. As a result, our consolidated gross operating margin amounts include 100% of the gross operating margin amounts of Duncan Energy Partners.

The following table presents our measurement of total segment gross operating margin for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2008	**2007**	**2008**	**2007**
Revenues (1)	$ 6,297,902	$ 4,111,996	$ 18,322,052	$ 11,647,656
Less: Operating costs and expenses (1)	(5,971,942)	(3,896,411)	(17,243,070)	(10,981,562)
Add: Equity in earnings of unconsolidated affiliates (1)	14,876	13,960	48,037	13,928
Depreciation, amortization and accretion in operating costs and expenses (2)	138,417	133,869	408,601	374,522
Operating lease expense paid by EPCO (2)	526	526	1,579	1,579
Loss (gain) from asset sales and related transactions in operating costs and expenses (2)	(857)	(219)	(1,699)	5,445
Total segment gross operating margin	$ 478,922	$ 363,721	$ 1,535,500	$ 1,061,568

(1) These amounts are taken from our Unaudited Condensed Statements of Consolidated Operations.
(2) These non-cash expenses are taken from the operating activities section of our Unaudited Condensed Statements of Consolidated Cash Flows.

A reconciliation of our total segment gross operating margin to operating income and income before provision for income taxes and minority interest follows:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2008	2007	2008	2007
Total segment gross operating margin	$ 478,922	$ 363,721	$ 1,535,500	$ 1,061,568
Adjustments to reconcile total segment gross operating margin to operating income:				
Depreciation, amortization and accretion in operating costs and expenses	(138,417)	(133,869)	(408,601)	(374,522)
Operating lease expense paid by EPCO	(526)	(526)	(1,579)	(1,579)
Gain (loss) from asset sales and related transactions in operating costs and expenses	857	219	1,699	(5,445)
General and administrative costs	(21,720)	(18,715)	(66,901)	(66,706)
Operating income	319,116	210,830	1,060,118	613,316
Other expense, net	(101,479)	(83,369)	(287,672)	(213,327)
Income before provision for income taxes and minority interest	$ 217,637	$ 127,461	$ 772,446	$ 399,989

The following table summarizes the contribution to consolidated revenues from the sale of NGL, natural gas and petrochemical products for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2008	2007	2008	2007
NGL Pipelines & Services:				
Sale of NGL products	$ 4,271,467	$ 2,837,465	$ 12,550,220	$ 7,952,147
Percent of consolidated revenues	68%	69%	68%	68%
Onshore Natural Gas Pipelines & Services:				
Sale of natural gas	851,748	406,482	2,407,930	1,190,235
Percent of consolidated revenues	14%	10%	13%	10%
Petrochemical Services:				
Sale of petrochemical products	708,745	444,670	1,928,840	1,268,731
Percent of consolidated revenues	11%	11%	11%	11%

Information by segment, together with reconciliations to our consolidated totals, is presented in the following table:

	Reportable Segments					
	NGL Pipelines & Services	Onshore Natural Gas Pipelines & Services	Offshore Pipelines & Services	Petrochemical Services	Adjustments and Eliminations	Consolidated Totals
Revenues from third parties:						
Three months ended September 30, 2008	$ 4,288,205	$ 823,245	$ 60,194	$ 826,099	$ --	$ 5,997,743
Three months ended September 30, 2007	2,873,937	428,807	54,444	575,969	--	3,933,157
Nine months ended September 30, 2008	12,544,242	2,456,275	197,326	2,300,602	--	17,498,445
Nine months ended September 30, 2007	8,261,659	1,304,239	142,557	1,559,887	--	11,268,342
Revenues (losses) from related parties:						
Three months ended September 30, 2008	140,839	154,566	4,754	--	--	300,159
Three months ended September 30, 2007	93,204	86,704	(1,069)	--	--	178,839
Nine months ended September 30, 2008	501,129	314,665	7,813	--	--	823,607
Nine months ended September 30, 2007	169,262	209,807	236	9	--	379,314
Intersegment and intrasegment revenues:						
Three months ended September 30, 2008	2,313,647	293,227	377	216,643	(2,823,894)	--
Three months ended September 30, 2007	1,265,697	57,635	484	132,844	(1,456,660)	--
Nine months ended September 30, 2008	6,431,479	635,992	1,109	529,821	(7,598,401)	--
Nine months ended September 30, 2007	3,540,347	119,121	1,531	360,885	(4,021,884)	--
Total revenues:						
Three months ended September 30, 2008	6,742,691	1,271,038	65,325	1,042,742	(2,823,894)	6,297,902
Three months ended September 30, 2007	4,232,838	573,146	53,859	708,813	(1,456,660)	4,111,996
Nine months ended September 30, 2008	19,476,850	3,406,932	206,248	2,830,423	(7,598,401)	18,322,052
Nine months ended September 30, 2007	11,971,268	1,633,167	144,324	1,920,781	(4,021,884)	11,647,656
Equity in earnings of unconsolidated affiliates:						
Three months ended September 30, 2008	3,009	5,598	5,987	282	--	14,876
Three months ended September 30, 2007	2,684	2,351	8,557	368	--	13,960
Nine months ended September 30, 2008	2,288	16,883	27,914	952	--	48,037
Nine months ended September 30, 2007	4,364	4,592	3,786	1,186	--	13,928
Gross operating margin by individual business segment and in total:						
Three months ended September 30, 2008	336,054	88,160	17,465	37,243	--	478,922
Three months ended September 30, 2007	190,209	75,424	46,676	51,412	--	363,721
Nine months ended September 30, 2008	943,445	321,237	134,353	136,465	--	1,535,500
Nine months ended September 30,						

2007	589,708	235,102	97,429	139,329		1,061,568
Segment assets:						
At September 30, 2008	5,248,670	3,922,181	1,407,855	696,966	1,417,947	12,693,619
At December 31, 2007	4,570,555	3,702,297	1,452,568	687,856	1,173,988	11,587,264
Investments in and advances to unconsolidated affiliates (see Note 7):						
At September 30, 2008	111,243	302,884	484,757	18,309	--	917,193
At December 31, 2007	117,089	239,327	484,588	17,335	--	858,339
Intangible assets, net (see Note 9):						
At September 30, 2008	348,538	342,336	120,215	55,224	--	866,313
At December 31, 2007	373,071	354,152	133,058	56,719	--	917,000
Goodwill (see Note 9):						
At September 30, 2008	179,050	282,121	82,135	73,690	--	616,996
At December 31, 2007	153,706	282,121	82,135	73,690	--	591,652

Our natural gas marketing business, which is included in our Onshore Natural Gas Pipelines & Services segment, has increased significantly during 2008. These marketing activities have four primary objectives: (i) to mitigate risk; (ii) maximize the use of our natural gas assets; (iii) to provide real-time market intelligence; and (iv) to link our noncontiguous natural gas assets together to enhance the profitability of such operations. To achieve these objectives, our natural gas marketing activities transact with various parties to provide transportation, balancing, storage, supply and sales services. The majority of our natural gas marketing activities are focused on the Gulf Coast and Rocky Mountain regions.

Our natural gas marketing business acquires a significant portion of the natural gas it sells from our processing plants and attracts additional supplies from third parties at pipeline interconnects to facilitate incremental throughput on our natural gas transportation pipelines. This purchased gas is then sold to industrial consumers, utilities and power plants at prices that include a transportation fee. In addition, sales are made with third party marketing companies at industry hub locations in order to balance our supply/demand portfolio. Our purchase and sale transactions are typically based on published daily or monthly index prices. We utilize financial instruments to hedge various transactions within our natural gas marketing business (see Note 4).

We use third party transportation and storage capacity to link together our noncontiguous natural gas assets. Our natural gas marketing business contracts with third party transportation and storage providers to provide services on both a firm and interruptible basis. This strategy allows us to compliment and strengthen our portfolio of natural gas assets.

Note 13. Related Party Transactions

The following table summarizes our revenue and expense transactions with related parties for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2008	**2007**	**2008**	**2007**
Revenues from consolidated operations:				
EPCO and affiliates	$ 47,215	$ 12,673	$ 91,922	$ 42,778
Energy Transfer Equity and subsidiaries	99,583	78,957	412,975	121,521
Unconsolidated affiliates	153,361	87,209	318,710	215,015
Total	$ 300,159	$ 178,839	$ 823,607	$ 379,314
Operating costs and expenses:				
EPCO and affiliates	$ 87,991	$ 72,296	$ 274,406	$ 219,879
Energy Transfer Equity and subsidiaries	56,528	2,614	134,447	8,385
Unconsolidated affiliates	20,688	6,414	68,214	22,628
Total	$ 165,207	$ 81,324	$ 477,067	$ 250,892
General and administrative costs:				
EPCO and affiliates	$ 13,403	$ 11,504	$ 44,631	$ 45,292
Unconsolidated affiliates	(37)	--	(37)	--
Total	$ 13,366	$ 11,504	$ 44,594	$ 45,292
Other expense:				
EPCO and affiliates	$ --	$ --	$ (274)	$ 170

We believe that the terms and provisions of our related party agreements are fair to us; however, such agreements and transactions may not be as favorable to us as we could have obtained from unaffiliated third parties.

Relationship with EPCO and affiliates

We have an extensive and ongoing relationship with EPCO and its affiliates, which include the following significant entities that are not part of our consolidated group of companies:

- EPCO and its private company subsidiaries;
- EPGP, our sole general partner;
- Enterprise GP Holdings, which owns and controls our general partner;
- TEPPCO, which is owned and controlled by Enterprise GP Holdings; and
- the Employee Partnerships (see Note 3).

We also have an ongoing relationship with Duncan Energy Partners, the financial statements of which are consolidated with those of our own. Our transactions with Duncan Energy Partners are eliminated in consolidation. A description of our relationship with Duncan Energy Partners is presented within this Note 13.

EPCO is a private company controlled by Dan L. Duncan, who is also a Director and Chairman of EPGP, our general partner. At September 30, 2008, EPCO and its affiliates beneficially owned 149,433,410 (or 34.1%) of our outstanding common units, which include 13,454,498 of our common units owned by Enterprise GP Holdings. In addition, at September 30, 2008, EPCO and its affiliates beneficially owned 77.8% of the limited partner interests of Enterprise GP Holdings and 100% of its general partner, EPE Holdings. Enterprise GP Holdings owns all of the membership interests of EPGP. The principal business activity of EPGP is to act as our managing partner. The executive officers and certain of the directors of EPGP and EPE Holdings are employees of EPCO.

As our general partner, EPGP received cash distributions of $106.4 million and $91.6 million from us during the nine months ended September 30, 2008 and 2007, respectively. These amounts include incentive distributions of $92.8 million and $79.0 million for the nine months ended September 30, 2008 and 2007, respectively.

We and EPGP are both separate legal entities apart from each other and apart from EPCO, Enterprise GP Holdings and their respective other affiliates, with assets and liabilities that are separate from those of EPCO, Enterprise GP Holdings and their respective other affiliates. EPCO and its private company subsidiaries depend on the cash distributions they receive from us, Enterprise GP Holdings and other investments to fund their other operations and to meet their debt obligations. EPCO and its private company affiliates received directly from us $300.2 million and $260.7 million in cash distributions during the nine months ended September 30, 2008 and 2007, respectively.

The ownership interests in us that are owned or controlled by Enterprise GP Holdings are pledged as security under its credit facility. In addition, substantially all of the ownership interests in us that are owned or controlled by EPCO and its affiliates, other than those interests owned by Enterprise GP Holdings, Dan Duncan LLC and certain trusts affiliated with Dan L. Duncan, are pledged as security under the credit facility of a private company affiliate of EPCO. This credit facility contains customary and other events of default relating to EPCO and certain affiliates, including Enterprise GP Holdings, TEPPCO and us.

We have entered into an agreement with an affiliate of EPCO to provide trucking services to us for the transportation of NGLs and other products. We also lease office space in various buildings from affiliates of EPCO. The rental rates in these lease agreements approximate market rates.

EPCO Administrative Services Agreement

We have no employees. All of our operating functions and general and administrative support services are provided by employees of EPCO pursuant to the ASA. We, Duncan Energy Partners, Enterprise GP Holdings, TEPPCO and our respective general partners are parties to the ASA. The ACG Committees of each general partner have approved the ASA.

Under the ASA, we reimburse EPCO for all costs and expenses it incurs in providing management, administrative and operating services for us, including compensation of employees (i.e., salaries, medical benefits and retirement benefits). Since the vast majority of such expenses are charged to us on an actual basis (i.e. no mark-up or subsidy is charged or received by EPCO), we believe that such expenses are representative of what the amounts would have been on a stand-alone basis. With respect to allocated costs, we believe that the proportional direct allocation method employed by EPCO is reasonable and reflective of the estimated level of costs we would have incurred on a stand-alone basis. The ASA also addresses potential conflicts in business opportunities that may arise among us, Enterprise GP Holdings, Duncan Energy Partners and other affiliates of EPCO.

Relationship with TEPPCO

TEPPCO became a related party to us in February 2005 when its general partner was acquired by private company affiliates of EPCO. Our relationship with TEPPCO was further reinforced by the acquisition of TEPPCO's general partner by Enterprise GP Holdings in May 2007. Enterprise GP Holdings also owns our general partner.

We received $47.2 million and $12.7 million from TEPPCO during the three months ended September 30, 2008 and 2007, respectively, from the sale of hydrocarbon products. We received $91.9 million and $42.8 million from TEPPCO during the nine months ended September 30, 2008 and 2007, respectively, from the sale of hydrocarbon products. We paid TEPPCO $5.9 million and $4.5 million for NGL pipeline transportation and storage services during the three months ended September 30, 2008 and 2007, respectively. We paid TEPPCO $21.9 million and $13.8 million for NGL pipeline transportation and storage services during the nine months ended September 30, 2008 and 2007, respectively.

In August 2006, we formed a joint venture with TEPPCO involving Jonah, which owns the Jonah Gas Gathering System located in the Greater Green River Basin of southwestern Wyoming. The Jonah Gas Gathering System gathers and transports natural gas produced from the Jonah and Pinedale fields to regional natural gas processing plants and major interstate pipelines that deliver natural gas to end-user markets. Currently, the gathering capacity of this system is 2.4 Bcf/d. We own an approximate 19.4% interest in Jonah and TEPPCO owns the remaining 80.6% interest. We account for our investment in the Jonah joint venture using the equity method of accounting.

During the first quarter of 2008, Jonah initiated a separate project to increase gathering capacity on that portion of its system that serves the Pinedale production field. This new project is expected to increase overall capacity of the Jonah Gas Gathering System by an additional 0.2 Bcf/d. The total anticipated cost of this new project is $125.0 million, of which we will be responsible for our share of the construction costs.

In August 2008, we, together with TEPPCO and Oiltanking, announced the formation of a joint venture to design, construct, operate and own a Texas offshore crude oil port and pipeline system to facilitate delivery of waterborne crude oil to refining centers located along the upper Texas Gulf Coast. See Note 7 for additional information regarding the Texas Offshore Port System joint venture.

Relationship with Duncan Energy Partners

On February 5, 2007, Duncan Energy Partners completed its initial public offering of 14,950,000 common units. At September 30, 2008, Enterprise Products Partners beneficially owned 5,351,571 of Duncan Energy Partners' common units. We also own the 2% general partner interest in Duncan Energy

Partners. EPO directs the business operations of Duncan Energy Partners through its ownership and control of the general partner of Duncan Energy Partners. For financial reporting purposes, we consolidate the financial statements of Duncan Energy Partners with those of our own.

As a result of contributions EPO made at the time of Duncan Energy Partners' initial public offering in February 2007, Duncan Energy Partners owns 66% of the equity interests in the following entities and EPO owns the remaining 34% of the equity interests:

- Mont Belvieu Caverns, LLC ("Mont Belvieu Caverns"),
- Acadian Gas, LLC ("Acadian Gas"),
- Sabine Propylene Pipeline L.P. ("Sabine Propylene"),
- Enterprise Lou-Tex Propylene Pipeline L.P. ("Lou-Tex Propylene"), and
- South Texas NGL Pipelines, LLC ("South Texas NGL").

We have significant involvement with all of the subsidiaries of Duncan Energy Partners, including the following types of transactions:

- We utilize storage services provided by Mont Belvieu Caverns to support our Mont Belvieu fractionation and other businesses;
- We buy natural gas from and sell natural gas to Acadian Gas in connection with its and our normal business activities; and
- We are currently the sole shipper on the DEP South Texas NGL Pipeline System.

EPO may contribute or sell other equity interests in its subsidiaries, or other of its or its subsidiaries' assets, to Duncan Energy Partners. EPO has no obligation or commitment to make such contributions or sales to Duncan Energy Partners.

Effective February 1, 2007, EPO is allocated all operational measurement gains and losses relating to Mont Belvieu Caverns' underground storage activities. Operational measurement gains and losses are created when product is moved between storage wells and are attributable to pipeline and well connection measurement variances. As a result, EPO is required each period to contribute cash to Mont Belvieu Caverns for net operational measurement losses and is entitled to receive distributions from Mont Belvieu Caverns for net operational measurement gains. Mont Belvieu Caverns recorded operational measurement gains of $1.1 million and losses of $3.8 million during the three and nine months ended September 30, 2008, respectively. For the three and eight months ended September 30, 2007, Mont Belvieu Caverns recorded operational measurement losses of $0.9 million and gains of $3.2 million, respectively. Operational measurement gains and losses are a component of gross operating margin for the NGL Pipelines & Services business segment; however, the related cash distributions from and contributions to Mont Belvieu Caverns are eliminated in the preparation of our consolidated financial statements.

Omnibus Agreement. In February 2007, EPO entered into an Omnibus Agreement with Duncan Energy Partners that governs the following matters:

- indemnification by EPO of certain environmental liabilities, tax liabilities and right-of-way defects with respect to assets EPO contributed to Duncan Energy Partners in February 2007;
- reimbursement by EPO of certain capital expenditures incurred by South Texas NGL and Mont Belvieu Caverns with respect to projects under construction at the time of Duncan Energy Partners' initial public offering;

- a right of first refusal to EPO in Duncan Energy Partners' current and future subsidiaries and a right of first refusal on the material assets of such subsidiaries, other than sales of inventory and other assets in the ordinary course of business; and

- a preemptive right with respect to equity securities issued by certain of Duncan Energy Partners' subsidiaries, other than as consideration in an acquisition or in connection with a loan or debt financing.

Neither EPO nor any of its affiliates are restricted under the Omnibus Agreement from competing against Duncan Energy Partners. As provided for in the EPCO ASA, EPO and its affiliates may acquire, construct or dispose of additional midstream energy or other assets in the future without any obligation to offer Duncan Energy Partners the opportunity to acquire or construct such assets.

As noted previously, EPO indemnified Duncan Energy Partners for certain environmental liabilities, tax liabilities and right-of-way defects associated with the assets EPO contributed to Duncan Energy Partners in February 2007. These indemnifications terminate on February 5, 2010. There is an aggregate cap of $15.0 million on the amount of indemnity coverage and Duncan Energy Partners is not entitled to indemnification until the aggregate amount of claims it incurs exceeds $250 thousand. Environmental liabilities resulting from a change of law after February 5, 2007 are excluded from the indemnity. Duncan Energy Partners made no claims to EPO during the three and nine months ended September 30, 2008 in connection with these indemnity provisions.

Under the Omnibus Agreement, EPO agreed to make additional cash contributions to South Texas NGL and Mont Belvieu Caverns to fund 100% of project costs in excess of (i) the $28.6 million of estimated costs to complete the Phase II expansion of the DEP South Texas NGL Pipeline System and (ii) the $14.1 million of estimated costs for additional Mont Belvieu brine production capacity and above-ground storage reservoir projects. These projects were in progress at the time of Duncan Energy Partners' initial public offering. EPO made cash contributions of $32.5 million under the Omnibus Agreement to the subsidiaries of Duncan Energy Partners during the nine months ended September 30, 2008. This amount was primarily contributed to South Texas NGL to fund costs of its Phase II pipeline project. We expect EPO to make contributions of approximately $2.1 million during the remainder of 2008 in satisfaction of its project funding obligations under the Omnibus Agreement.

EPO will not receive an increased allocation of earnings or cash flows as a result of these contributions to South Texas NGL and Mont Belvieu Caverns. EPO's payments under the Omnibus Agreement are accounted for as additional investments by EPO in the underlying companies and are subsequently eliminated in the preparation of our consolidated financial statements.

Mont Belvieu Caverns' LLC Agreement. The Mont Belvieu Caverns' LLC Agreement (the "Caverns LLC Agreement") states that if Duncan Energy Partners elects to not participate in certain projects of Mont Belvieu Caverns, then EPO is responsible for funding 100% of such projects. To the extent such non-participated projects generate identifiable incremental cash flows for Mont Belvieu Caverns in the future, the earnings and cash flows of Mont Belvieu Caverns will be adjusted to allocate such incremental amounts to EPO by special allocation or otherwise. Under the terms of the Caverns LLC Agreement, Duncan Energy Partners may elect to acquire a 66% share of these projects from EPO within 90 days of such projects being placed in-service. In November 2008, the Caverns LLC Agreement was amended to provide that EPO would prospectively receive a special allocation of 100% of the depreciation related to projects that it has fully funded.

EPO made cash contributions of $86.4 million under the Caverns LLC Agreement during the nine months ended September 30, 2008. These expenditures are associated with storage-related projects sponsored by EPO's NGL marketing activities and represent 100% of the costs of such projects to date. EPO expects that its NGL marketing activities will benefit from these projects. At present, Mont Belvieu Caverns is not expected to generate any identifiable incremental cash flows in connection with these projects; thus, the sharing ratio for Mont Belvieu Caverns is not expected to change from the current ratio of 66% for Duncan Energy Partners and 34% for EPO. However, as noted above, beginning in November 2008, EPO will receive a special allocation of depreciation related to these projects. We expect EPO to make $37.5 million of contributions to Mont Belvieu Caverns in connection with these construction projects during the remainder of 2008 through the first quarter of 2009. The constructed assets are the property of Mont Belvieu Caverns.

EPO's payments under the Caverns LLC Agreement are accounted for as additional investments by EPO in Mont Belvieu Caverns and are subsequently eliminated in the preparation of our consolidated financial statements.

Relationship with Energy Transfer Equity

Enterprise GP Holdings acquired equity method investments in Energy Transfer Equity and its general partner in May 2007. As a result, Energy Transfer Equity and its consolidated subsidiaries became related parties to our consolidated businesses.

For the three and nine months ended September 30, 2008, we recorded $99.6 million and $413.0 million of revenues, respectively, from Energy Transfer Partners, L.P. ("ETP"), primarily from our NGL marketing activities. For the three and five months ended September 30, 2007, we recorded $79.0 million and $ 121.5 million, respectively, of revenues from ETP. We incurred $56.5 million and $134.4 million in operating costs and expenses for the three and nine months ended September 30, 2008, respectively, that were paid to ETP. For the three and five months ended September 30, 2007, we incurred $2.6 million and $8.4 million, respectively, in operating costs and expenses. We have a long-term revenue generating contract with Titan Energy Partners, L.P. ("Titan"), a consolidated subsidiary of ETP. Titan purchases substantially all of its propane requirements from us. We and Energy Transfer Company ("ETC OLP") transport natural gas on each other's systems and share operating expenses on certain pipelines. ETC OLP also sells natural gas to us.

Relationships with Unconsolidated Affiliates

Our significant related party revenue and expense transactions with unconsolidated affiliates consist of the sale of natural gas to Evangeline and the purchase of NGL storage, transportation and fractionation services from Promix. In addition, we sell natural gas to Promix and process natural gas at VESCO. For additional information regarding our unconsolidated affiliates, see Note 7.

See "Relationship with TEPPCO" within this Note 13 for a description of ongoing transactions involving our Jonah and TOPS joint ventures with TEPPCO.

Note 14. Earnings Per Unit

Basic earnings per unit is computed by dividing net income or loss allocated to limited partner interests by the weighted-average number of distribution-bearing units outstanding during a period. Diluted earnings per unit is computed by dividing net income or loss allocated to limited partner interests by the sum of (i) the weighted-average number of distribution-bearing units outstanding during a period (as used in determining basic earnings per unit); (ii) the weighted-average number of performance-based phantom units outstanding during a period; and (iii) the number of incremental common units resulting from the assumed exercise of dilutive unit options outstanding during a period (the "incremental option units").

In a period of net losses, restricted units, phantom units and incremental option units are excluded from the calculation of diluted earnings per unit due to their antidilutive effect. The dilutive incremental option units are calculated using the treasury stock method, which assumes that proceeds from the exercise of all in-the-money options at the end of each period are used to repurchase common units at an average market value during the period. The amount of common units remaining after the proceeds are exhausted represents the potentially dilutive effect of the securities.

The amount of net income or loss allocated to limited partner interests is net of our general partner's share of such earnings. The following table presents the allocation of net income to EPGP for the periods indicated:

	For the Three Months Ended September 30, 2008	For the Three Months Ended September 30, 2007	For the Nine Months Ended September 30, 2008	For the Nine Months Ended September 30, 2007
Net income	$ 203,081	$ 117,606	$ 725,960	$ 371,805
Less incentive earnings allocations to EPGP	(32,035)	(27,394)	(92,803)	(78,964)
Net income available after incentive earnings allocation	171,046	90,212	633,157	292,841
Multiplied by EPGP ownership interest	2.0%	2.0%	2.0%	2.0%
Standard earnings allocation to EPGP	$ 3,421	$ 1,804	$ 12,663	$ 5,857
Incentive earnings allocation to EPGP	$ 32,035	$ 27,394	$ 92,803	$ 78,964
Standard earnings allocation to EPGP	3,421	1,804	12,663	5,857
Net income available to EPGP	$ 35,456	$ 29,198	$ 105,466	$ 84,821

The following table presents our calculation of basic and diluted earnings per unit for the periods indicated:

	For the Three Months Ended September 30, 2008	For the Three Months Ended September 30, 2007	For the Nine Months Ended September 30, 2008	For the Nine Months Ended September 30, 2007
Net income	$ 203,081	$ 117,606	$ 725,960	$ 371,805
Net income available to EPGP	(35,456)	(29,198)	(105,466)	(84,821)
Net income available to limited partners	$ 167,625	$ 88,408	$ 620,494	$ 286,984
BASIC EARNINGS PER UNIT				
Numerator				
Income before EPGP earnings allocation	$ 203,081	$ 117,606	$ 725,960	$ 371,805
Net income available to EPGP	(35,456)	(29,198)	(105,466)	(84,821)
Net income available to limited partners	$ 167,625	$ 88,408	$ 620,494	$ 286,984
Denominator				
Common units	435,313	432,805	434,629	432,221
Time-vested restricted units	2,261	1,645	1,941	1,364
Total	437,574	434,450	436,570	433,585
Basic earnings per unit				
Income before EPGP earnings allocation	$ 0.46	$ 0.27	$ 1.66	$ 0.86
Net income available to EPGP	(0.08)	(0.07)	(0.24)	(0.20)
Net income available to limited partners	$ 0.38	$ 0.20	$ 1.42	$ 0.66
DILUTED EARNINGS PER UNIT				
Numerator				
Income before EPGP earnings allocation	$ 203,081	$ 117,606	$ 725,960	$ 371,805
Net income available to EPGP	(35,456)	(29,198)	(105,466)	(84,821)
Net income available to limited partners	$ 167,625	$ 88,408	$ 620,494	$ 286,984
Denominator				
Common units	435,313	432,805	434,629	432,221
Time-vested restricted units	2,261	1,645	1,941	1,364
Performance-based restricted units	3	9	7	9
Incremental option units	201	354	287	480
Total	437,778	434,813	436,864	434,074
Diluted earnings per unit				
Income before EPGP earnings allocation	$ 0.46	$ 0.27	$ 1.66	$ 0.86
Net income available to EPGP	(0.08)	(0.07)	(0.24)	(0.20)
Net income available to limited partners	$ 0.38	$ 0.20	$ 1.42	$ 0.66

Note 15. Commitments and Contingencies

Litigation

On occasion, we or our unconsolidated affiliates are named as a defendant in litigation relating to our normal business activities, including regulatory and environmental matters. Although we are insured against various business risks to the extent we believe it is prudent, there is no assurance that the nature and amount of such insurance will be adequate, in every case, to indemnify us against liabilities arising from future legal proceedings as a result of our ordinary business activities. We are unaware of any significant litigation, pending or threatened, that could have a significant adverse effect on our financial position, results of operations or cash flows.

On September 18, 2006, Peter Brinckerhoff, a purported unitholder of TEPPCO, filed a complaint in the Court of Chancery of New Castle County in the State of Delaware, in his individual capacity, as a putative class action on behalf of other unitholders of TEPPCO, and derivatively on behalf of TEPPCO, concerning, among other things, certain transactions involving TEPPCO and us or our affiliates. Mr. Brinkerhoff filed an amended complaint on July 12, 2007. The complaint names as defendants (i) TEPPCO, certain of its current and former directors, and certain of its affiliates; (ii) us and certain of our affiliates; (iii) EPCO; and (iv) Dan L. Duncan.

The amended complaint alleges, among other things, that the defendants caused TEPPCO to enter into certain transactions that were unfair to TEPPCO or otherwise unfairly favored Enterprise Products Partners or its affiliates over TEPPCO. These transactions are alleged to include: (i) the joint venture to further expand the Jonah system entered into by TEPPCO and Enterprise Products Partners in August 2006; (ii) the sale by TEPPCO of its Pioneer natural gas processing plant to Enterprise Products Partners in March 2006; and (iii) certain amendments to TEPPCO’s partnership agreement, including a reduction in the maximum tier of TEPPCO’s incentive distribution rights in exchange for TEPPCO common units. The amended complaint seeks (i) rescission of the amendments to TEPPCO’s partnership agreement; (ii) damages for profits and special benefits allegedly obtained by defendants as a result of the alleged wrongdoings in the amended complaint; and (iii) awarding plaintiff costs of the action, including fees and expenses of his attorneys and experts. We believe this lawsuit is without merit and intend to vigorously defend against it. See Note 13 for additional information regarding our relationship with TEPPCO.

On February 14, 2007, EPO received a letter from the Environment and Natural Resources Division (“ENRD”) of the U.S. Department of Justice (“DOJ”) related to an ammonia release in Kingman County, Kansas on October 27, 2004 from a pressurized anhydrous ammonia pipeline owned by a third party, Magellan Ammonia Pipeline, L.P. (“Magellan”) and a previous release of ammonia on September 27, 2004 from the same pipeline. EPO was the operator of this pipeline until July 1, 2008. The ENRD has indicated that it may pursue civil damages against EPO and Magellan as a result of these incidents. Based on this correspondence from the ENRD, the statutory maximum amount of civil fines that could be assessed against EPO and Magellan is up to $17.4 million in the aggregate. EPO is cooperating with the DOJ and is hopeful that an expeditious resolution of this civil matter acceptable to all parties will be reached in the near future. Magellan has agreed to indemnify EPO for the civil matter. At this time, we do not believe that a final resolution of the civil claims by the ENRD will have a material impact on our consolidated financial position, results of operations or cash flows.

On October 25, 2006, a rupture in the Magellan Ammonia Pipeline resulted in the release of ammonia near Clay Center, Kansas. The pipeline has been repaired and environmental remediation tasks related to this incident have been completed. At this time, we do not believe that this incident will have a material impact on our consolidated financial position, results of operations or cash flows.

Several lawsuits have been filed by municipalities and other water suppliers against a number of manufacturers of reformulated gasoline containing methyl tertiary butyl ether. In general, such suits have not named manufacturers of this product as defendants, and there have been no such lawsuits filed against our subsidiary that owns an octane-additive production facility. It is possible, however, that former manufacturers such as our subsidiary could ultimately be added as defendants in such lawsuits or in new lawsuits.

The Attorney General of Colorado on behalf of the Colorado Department of Public Health and Environment filed suit against us and others on April 15, 2008 in connection with the construction of a pipeline near Parachute, Colorado. The State sought a temporary restraining order and an injunction to halt construction activities since it alleged that the defendants failed to install measures to minimize damage to the environment and to follow requirements for the pipeline's stormwater permit and appropriate stormwater plan. The State's complaint also seeks penalties for the above alleged failures. Defendants and the State agreed to certain stipulations that, among other things, require us to install specified environmental protection measures in the disturbed pipeline right-of-way to comply with regulations. We have complied with the stipulations and the State has dismissed the portions of the complaint seeking the temporary restraining order and injunction. The State has not yet assessed penalties and we are unable to predict the amount of penalties that may be assessed. At this time, we do not believe that this incident will have a material impact on our consolidated financial position, results of operations or cash flows.

Contractual Obligations

Operating Lease Obligations. We lease certain property, plant and equipment under noncancelable and cancelable operating leases. Our significant lease agreements involve (i) the lease of underground caverns for the storage of natural gas and NGLs, (ii) leased office space with affiliates of EPCO, (iii) a railcar unloading terminal in Mont Belvieu, Texas and (iv) land held pursuant to right-of-way agreements. In general, our material lease agreements have original terms that range from two to 28 years and include renewal options that could extend the agreements for up to an additional 20 years. Lease expense is charged to operating costs and expenses on a straight-line basis over the period of expected economic benefit. Contingent rental payments are expensed as incurred.

Lease and rental expense was \$8.5 million and \$9.0 million during the three months ended September 30, 2008 and 2007, respectively. For the nine months ended September 30, 2008 and 2007, lease and rental expense was \$26.9 million and \$28.9 million, respectively. There have been no material changes in our operating lease commitments since December 31, 2007.

Scheduled Maturities of Long-Term Debt. With the exception of the issuance of Senior Notes M and N by EPO in April 2008 and routine fluctuations in the balance of our consolidated revolving credit facilities, there have been no significant changes in our consolidated scheduled maturities of long-term debt since those reported in our Annual Report on Form 10-K for the year ended December 31, 2007. See Note 10 for additional information regarding the issuance of senior notes by EPO.

Purchase Obligations. There have been no material changes in our consolidated purchase obligations since December 31, 2007, except for commitments associated with two long-term natural gas purchase agreements and certain pipeline capacity reservation agreements that we executed in 2008 to support our natural gas marketing activities. The following table presents our estimated purchase commitments (in terms of volumes and cost) under these new agreements for the periods indicated:

		Payment or Settlement due by Period			
	Total	Less than 1 year	1-3 years	4-5 years	More than 5 years
Product purchase commitments:					
Estimated payment obligations:					
Natural gas	$ 5,707,213	$ 261,703	$ 985,430	$ 1,232,670	$ 3,227,410
Underlying volume commitment:					
Natural gas (in billion British thermal units)	927,765	45,360	158,775	199,505	524,125
Service payment commitments					
for pipeline capacity reservation	$ 157,633	$ 2,730	$ 27,414	$ 30,074	$ 97,415

Estimated future payment obligations for natural gas shown in the preceding table are based on the contractual price under each contract for purchases made at September 30, 2008 applied to all future volume commitments. Actual future payment obligations under these natural gas purchase agreements will vary depending on market prices at the time of delivery.

Other Claims

As part of our normal business activities with joint venture partners and certain customers and suppliers, we occasionally have claims made against us as a result of disputes related to contractual agreements or similar arrangements. As of September 30, 2008, claims against us totaled approximately $3.0 million. These matters are in various stages of assessment and the ultimate outcome of such disputes cannot be reasonably estimated. However, in our opinion, the likelihood of a material adverse outcome related to such disputes is remote. Accordingly, accruals for loss contingencies related to these matters, if any, that might result from the resolution of such disputes have not been reflected in our consolidated financial statements.

Note 16. Significant Risks and Uncertainties – Weather-Related Risks

We participate as a named insured in EPCO's insurance program, which provides us with property damage, business interruption and other coverages, the scope and amounts of which are customary and sufficient for the nature and extent of our operations. While we believe EPCO maintains adequate insurance coverage on our behalf, insurance will not cover every type of interruption that might occur. If we were to incur a significant liability for which we were not fully insured, it could have a material impact on our consolidated financial position, results of operations and cash flows. In addition, the proceeds of any such insurance may not be paid in a timely manner and may be insufficient to reimburse us for our repair costs or lost income. Any event that interrupts the revenues generated by our consolidated operations, or which causes us to make significant expenditures not covered by insurance, could reduce our ability to pay distributions to our partners and, accordingly, adversely affect the market price of our common units.

For windstorm events such as hurricanes and tropical storms, EPCO's deductible for onshore physical damage is $10.0 million per storm. For offshore assets, the windstorm deductible is $10.0 million per storm plus a one-time $15.0 million aggregate deductible per policy period. For non-windstorm events, EPCO's deductible for onshore and offshore physical damage is $5.0 million per occurrence. In meeting the deductible amounts, property damage costs are aggregated for EPCO and its affiliates, including us. Accordingly, our exposure with respect to the deductibles may be equal to or less than the stated amounts depending on whether other EPCO or affiliate assets are also affected by an event.

To qualify for business interruption coverage in connection with a windstorm event, covered assets must be out-of-service in excess of 60 days for onshore assets and 75 days for offshore assets. To qualify for business interruption coverage in connection with a non-windstorm event, covered onshore and offshore assets must be out-of-service in excess of 60 days.

Hurricanes Gustav and Ike

In the third quarter of 2008, our onshore and offshore facilities located along the Gulf Coast of Texas and Louisiana were adversely impacted by Hurricanes Gustav and Ike. The disruptions in natural gas, NGL and crude oil production caused by these storms resulted in decreased volumes for some of our pipeline systems, natural gas processing plants, NGL fractionators and offshore platforms, which, in turn, caused a decrease in gross operating margin from these operations. As a result of our allocated share of EPCO's insurance deductibles for windstorm coverage, we expensed a combined $46.0 million of repair costs for property damage in connection with these two storms. We expect to file property damage insurance claims to the extent repair costs exceed this amount. Due to the recent nature of these storms, we are still evaluating the total cost of repairs and the potential for business interruption claims on certain assets.

Pre-2008 Hurricanes (Katrina, Rita, et al)

The following table summarizes the proceeds we received from business interruption and property damage insurance claims with respect to certain named storms for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2008	**2007**	**2008**	**2007**
Business interruption proceeds:				
Hurricane Ivan	$ --	$ --	$ --	$ 377
Hurricane Katrina	--	1,301	501	14,500
Hurricane Rita	--	743	662	9,000
Other	--	--	--	996
Total proceeds	--	2,044	1,163	24,873
Property damage proceeds:				
Hurricane Ivan	--	--	--	1,273
Hurricane Katrina	2,495	--	9,404	6,563
Hurricane Rita	--	--	2,678	--
Other	--	--	--	184
Total proceeds	2,495	--	12,082	8,020
Total	$ 2,495	$ 2,044	$ 13,245	$ 32,893

At September 30, 2008, we have $30.8 million of estimated property damage claims outstanding related to these storms that we believe are probable of collection through 2009. To the extent we estimate the dollar value of such damages, please be aware that a change in our estimates may occur as additional information becomes available.

Note 17. Supplemental Cash Flow Information

Third parties may be obligated to reimburse us for all or a portion of expenditures on certain of our capital projects. The majority of such arrangements are associated with projects related to pipeline construction and production well tie-ins. We received $21.2 million and $52.5 million as contributions in aid of our construction costs during the nine months ended September 30, 2008 and 2007, respectively.

We determine net cash flows provided by operating activities using the indirect method, which adjusts net income for items that did not affect cash. Under GAAP, we use the accrual basis of accounting to determine net income. This basis of accounting requires that we record revenue when earned and expenses when incurred. Earned revenues may include credit sales that have not been collected in cash and expenses incurred that may not have been paid in cash. The extent to which changes in operating accounts influence net cash flows provided by operating activities generally depends on the following:

- The timing of cash receipts from revenue transactions and cash payments for expense transactions near the end of each reporting period. For example, if significant cash receipts are posted on the last day of the current reporting period, but subsequent payments on expense invoices are made on the first day of the next reporting period, net cash flows provided by operating activities will reflect an increase in the current reporting period that will be reduced as payments are made in the next period. We employ prudent cash management practices and monitor our daily cash requirements to meet our ongoing liquidity needs.

- If commodity or other prices increase between reporting periods, changes in accounts receivable and accounts payable and accrued expenses may appear larger than in previous periods; however, overall levels of receivables and payables may still reflect normal ranges. From a receivables standpoint, we monitor the amount of credit extended to customers.

- Additions to inventory for forward sales transactions or other reasons or increased expenditures for prepaid items would be reflected as a use of cash and reduce overall cash provided by operating activities in a given reporting period. As these assets are charged to expense in subsequent periods, the expense amount is reflected as a positive change in operating accounts; however, there is no impact on operating cash flows.

In addition to the adjustments noted above, non-cash charges in the income statement are added back to net income and non-cash credits are deducted to compute net cash flows provided by operating activities. Examples of non-cash charges include depreciation and amortization.

The net effect of changes in operating assets and liabilities is as follows for the periods indicated:

	For the Nine Months Ended September 30, 2008	For the Nine Months Ended September 30, 2007
Decrease (increase) in:		
Accounts and notes receivable	$ 84,900	$ (281,949)
Inventories	(299,124)	(170,610)
Prepaid and other current assets	(43,928)	(41,171)
Other assets	24,236	4,719
Increase (decrease) in:		
Accounts payable	(5,951)	61,106
Accrued product payable	14,192	354,508
Accrued expenses	27,177	152,534
Accrued interest	(29,009)	10,020
Other current liabilities	7,691	26,110
Other long-term liabilities	(8,581)	(4,995)
Net effect of changes in operating accounts	$ (228,397)	$ 110,272

Note 18. Condensed Financial Information of EPO

EPO conducts substantially all of our business. Currently, we have no independent operations and no material assets outside those of EPO. EPO consolidates the financial statements of Duncan Energy Partners with those of its own.

Enterprise Products Partners L.P. guarantees the debt obligations of EPO, with the exception of the Dixie revolving credit facility and the Duncan Energy Partners' revolving credit facility. If EPO were to default on any of its guaranteed debt, Enterprise Products Partners L.P. would be responsible for full repayment of that obligation. See Note 10 for additional information regarding our consolidated debt obligations.

The reconciling items between our consolidated financial statements and those of EPO are insignificant. The following table presents condensed consolidated statements of operations data for EPO for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2008	2007	2008	2007
Revenues	$ 6,297,902	$ 4,111,996	$ 18,322,052	$ 11,647,656
Costs and expenses	5,993,391	3,917,172	17,308,464	11,046,151
Equity in earnings of unconsolidated affiliates	14,876	13,960	48,037	13,928
Operating income	319,387	208,784	1,061,625	615,433
Other expense, net	(101,481)	(84,001)	(287,679)	(215,088)
Income before provision for income taxes and minority interest	217,906	124,783	773,946	400,345
Provision for income taxes	(6,609)	(2,072)	(17,193)	(9,006)
Income before minority interest	211,297	122,711	756,753	391,339
Minority interest	(7,998)	(7,804)	(29,454)	(19,325)
Net income	$ 203,299	$ 114,907	$ 727,299	$ 372,014

The following table presents condensed consolidated balance sheet data for EPO at the dates indicated:

	September 30, 2008	December 31, 2007
ASSETS		
Current assets	$ 2,993,491	$ 2,545,297
Property, plant and equipment, net	12,693,619	11,587,264
Investments in and advances to unconsolidated affiliates, net	917,193	858,339
Intangible assets, net	866,313	917,000
Goodwill	616,996	591,652
Deferred tax asset	2,320	3,113
Other assets	69,067	112,345
Total	$ 18,158,999	$ 16,615,010
LIABILITIES AND MEMBERS' EQUITY		
Current liabilities	$ 3,170,816	$ 3,044,002
Long-term debt	8,458,195	6,906,145
Other long-term liabilities	89,263	95,112
Minority interest	422,499	439,854
Members' equity	6,018,226	6,129,897
Total	$ 18,158,999	$ 16,615,010
Total EPO debt obligations guaranteed by Enterprise Products Partners L.P.	$ 8,212,201	$ 6,686,500

Item 2. ***Management's Discussion and Analysis of Financial Condition and Results of Operations*.**

For the three and nine months ended September 30, 2008 and 2007.

The following information should be read in conjunction with our Unaudited Condensed Consolidated Financial Statements and our accompanying notes included under Item 1 of this Quarterly Report on Form 10-Q and with the information contained within our Annual Report on Form 10-K for the year ended December 31, 2007. Our discussion and analysis includes the following:

- Cautionary Note Regarding Forward-Looking Statements.
- Significant Relationships Referenced in this Discussion and Analysis.
- Overview of Business.
- Recent Developments – Discusses significant developments since December 31, 2007.
- Results of Operations – Discusses material period-to-period variances in our Unaudited Condensed Statements of Consolidated Operations.
- Liquidity and Capital Resources – Addresses available sources of liquidity and capital resources and includes a discussion of our capital spending program.
- Overview of Critical Accounting Policies and Estimates.
- Other Items – Includes information related to contractual obligations, off-balance sheet arrangements, related party transactions, recent accounting pronouncements and similar disclosures.

As generally used in the energy industry and in this discussion, the identified terms have the following meanings:

/d	= per day
BBtus	= billion British thermal units
Bcf	= billion cubic feet
MBPD	= thousand barrels per day
MMBbls	= million barrels
MMBtus	= million British thermal units
MMcf	= million cubic feet

Our financial statements have been prepared in accordance with U.S. generally accepted accounting principles ("GAAP").

Cautionary Note Regarding Forward-Looking Statements

This discussion contains various forward-looking statements and information that are based on our beliefs and those of our general partner, as well as assumptions made by us and information currently available to us. When used in this document, words such as "anticipate," "project," "expect," "plan," "seek," "goal," "forecast," "intend," "could," "should," "will," "believe," "may," "potential" and similar expressions and statements regarding our plans and objectives for future operations, are intended to identify forward-looking statements. Although we and our general partner believe that such expectations reflected in such forward-looking statements are reasonable, neither we nor our general partner can give any assurances that such expectations will prove to be correct. Such statements are subject to a variety of risks, uncertainties and assumptions as described in more detail in Part I, Item 1A, "Risk Factors," included in our Annual Report on Form 10-K for 2007. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary *materially from those anticipated, estimated, projected or expected. You should not put undue reliance on any forward-looking statements.*

Significant Relationships Referenced in this Discussion and Analysis

Unless the context requires otherwise, references to “we,” “us,” “our” or “Enterprise Products Partners” are intended to mean the business and operations of Enterprise Products Partners L.P. and its consolidated subsidiaries.

References to “EPO” mean Enterprise Products Operating LLC, which is a wholly owned subsidiary of Enterprise Products Partners.

References to “Duncan Energy Partners” mean Duncan Energy Partners L.P., which is a consolidated subsidiary of EPO. Duncan Energy Partners is a publicly traded Delaware limited partnership, the common units of which are listed on the New York Stock Exchange (“NYSE”) under the ticker symbol “DEP.” References to “DEP GP” mean DEP Holdings, LLC, which is the general partner of Duncan Energy Partners and is wholly owned by EPO.

References to “EPGP” mean Enterprise Products GP, LLC, which is our general partner.

References to “Enterprise GP Holdings” mean Enterprise GP Holdings L.P., a publicly traded affiliate, the units of which are listed on the NYSE under the ticker symbol “EPE.” Enterprise GP Holdings owns EPGP. References to “EPE Holdings” mean EPE Holdings, LLC, which is the general partner of Enterprise GP Holdings.

References to “TEPPCO” mean TEPPCO Partners, L.P., a publicly traded affiliate, the common units of which are listed on the NYSE under the ticker symbol “TPP.” References to “TEPPCO GP” refer to Texas Eastern Products Pipeline Company, LLC, which is the general partner of TEPPCO and is wholly owned by Enterprise GP Holdings.

References to “Energy Transfer Equity” mean the business and operations of Energy Transfer Equity, L.P. and its consolidated subsidiaries, which include Energy Transfer Partners, L.P. (“ETP”). Energy Transfer Equity is a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol “ETE.” The general partner of Energy Transfer Equity is LE GP, LLC (“LE GP”). On May 7, 2007, Enterprise GP Holdings acquired non-controlling interests in both LE GP and Energy Transfer Equity. Enterprise GP Holdings accounts for its investments in LE GP and Energy Transfer Equity using the equity method of accounting.

References to “Employee Partnerships” mean EPE Unit L.P. (“EPE Unit I”), EPE Unit II, L.P. (“EPE Unit II”), EPE Unit III, L.P. (“EPE Unit III”) and Enterprise Unit L.P. (“Enterprise Unit”), collectively, which are private company affiliates of EPCO, Inc.

References to “EPCO” mean EPCO, Inc. and its wholly-owned private company affiliates, which are related parties to all of the foregoing named entities.

Overview of Business

We are a North American midstream energy company providing a wide range of services to producers and consumers of natural gas, natural gas liquids (“NGLs”), crude oil and certain petrochemicals. In addition, we are an industry leader in the development of pipeline and other midstream energy infrastructure in the continental United States and Gulf of Mexico. We are a publicly traded Delaware limited partnership formed in 1998, the common units of which are listed on the NYSE under the ticker symbol “EPD.”

Our midstream energy asset network links producers of natural gas, NGLs and crude oil from some of the largest supply basins in the United States, Canada and the Gulf of Mexico with domestic consumers and international markets. We have four reportable business segments: NGL Pipelines & Services; Onshore Natural Gas Pipelines & Services; Offshore Pipelines & Services; and Petrochemical Services. Our business segments are generally organized and managed according to the type of services rendered (or technologies employed) and products produced and/or sold.

We conduct substantially all of our business through EPO. We are owned 98% by our limited partners and 2% by our general partner, EPGP. EPGP is owned 100% by Enterprise GP Holdings. We, EPO, Duncan Energy Partners, DEP GP, EPGP, Enterprise GP Holdings, EPE Holdings, TEPPCO and TEPPCO GP are affiliates and under the common control of Dan L. Duncan, the Group Co-Chairman and the controlling shareholder of EPCO.

Recent Developments

The following information highlights our significant developments since January 1, 2008 through the date of this filing.

Texas Offshore Port System Joint Venture

In August 2008, we, together with TEPPCO and Oiltanking Holding Americas, Inc. ("Oiltanking"), announced the formation of a joint venture to design, construct, operate and own a Texas offshore crude oil port and related pipeline and storage infrastructure that would facilitate delivery of waterborne crude oil to refining centers located along the upper Texas Gulf Coast. Demand for such projects is being driven by planned and expected refinery expansions along the Gulf Coast, expected increases in shipping traffic and operating limitations of regional ship channels.

The joint venture's primary project, referred to as "TOPS," includes (i) an offshore port (which will be located approximately 36 miles from Freeport, Texas), (ii) an onshore storage facility with approximately 3.9 million barrels of crude oil storage capacity, and (iii) an 85-mile crude oil pipeline system having a transportation capacity of up to 1.8 million barrels per day, that will extend from the offshore port to a Texas City, Texas storage facility. TOPS is expected to begin service as early as the fourth quarter of 2010. The joint venture's second and complementary project, referred to as the Port Arthur Crude Oil Express (or "PACE") will transport crude oil from Texas City, including crude oil from TOPS, and will consist of a 75-mile pipeline and 1.2 million barrels of crude oil storage capacity in the Port Arthur, Texas area. PACE is expected to begin service as early as the third quarter of 2010. Development of the TOPS and PACE projects is supported by long-term contracts with affiliates of Motiva Enterprises LLC and Exxon Mobil Corporation, which have committed a combined 725,000 barrels per day of crude oil to the projects.

We, TEPPCO and Oiltanking each own, through our respective subsidiaries, a one-third interest in the joint venture. The aggregate cost of the TOPS and PACE projects is expected to be approximately $1.8 billion (excluding capitalized interest), with the majority of such capital expenditures occurring in 2009 and 2010. We and TEPPCO have each guaranteed up to approximately $700.0 million of the capital contribution obligations of our respective subsidiary partners in the joint venture. As of September 30, 2008, our investment in TOPS was $2.4 million.

Acquisition of Remaining Interest in Dixie

In August 2008, we acquired the remaining 25.8% ownership interest in Dixie Pipeline Company ("Dixie") for $57.1 million. As a result of this transaction, we own 100% of Dixie, which owns a 1,300-mile pipeline system that delivers NGLs (primarily propane and other chemical feedstocks) to customers along the U.S. Gulf Coast and southeastern United States.

Reorganization of Commercial Management Team

In July 2008, Mr. A. J. Teague, Executive Vice President, was elected as a Director to the boards of both our general partner and that of Duncan Energy Partners and as Chief Commercial Officer responsible for managing all of the commercial activities of the two partnerships. In connection with Mr. Teague's appointment as Chief Commercial Officer, certain members of our senior management team were realigned to report to Mr. Teague. Mr. Teague will continue to report to Michael A. Creel, President and Chief Executive Officer of Enterprise Products Partners.

Independence Trail and Hub Resume Operations

In April 2008, production at the Independence Hub natural gas platform was shut-in due to a leak in the flex-joint assembly where the Independence Trail export pipeline connects to the platform. In July 2008, repairs were completed and the Independence Hub platform and Trail pipeline returned to operation. Our Independence Trail export pipeline recorded $17.0 million of expense associated with the flex-joint repairs. We have submitted a claim with our insurance carriers regarding the flex-joint repair costs. To the extent that we receive cash proceeds from this claim in the future, such amounts would be recorded as income in the period of receipt.

EPO Issues $1.10 Billion of Senior Notes

In April 2008, EPO sold $400.0 million in principal amount of 5.65% fixed-rate, unsecured senior notes due April 2013 ("Senior Notes M") and $700.0 million in principal amount of 6.50% fixed-rate, unsecured senior notes due January 2019 ("Senior Notes N"). Net proceeds from this offering were used to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility. For additional information regarding this issuance of debt, see Note 10 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this Quarterly Report.

Duncan Energy Partners' Shelf Registration Statement

In March 2008, Duncan Energy Partners filed a universal shelf registration statement with the U.S. Securities and Exchange Commission ("SEC") that authorized its issuance of up to $1.00 billion in debt and equity securities. Duncan Energy Partners has not issued any securities under this registration statement through November 3, 2008.

Our Pioneer Cryogenic Natural Gas Processing Facility Commences Operations

In February 2008, we commenced operations at our recently completed Pioneer cryogenic natural gas processing facility. Located near the Opal Hub in southwestern Wyoming, this new facility is designed to process up to 750 MMcf/d of natural gas and extract as much as 30 MBPD of NGLs. We intend to maintain the operational capability of our Pioneer silica gel natural gas processing plant, which is located adjacent to the Pioneer cryogenic plant, as a back-up to provide producers with additional assurance of our processing capability at the complex. NGLs extracted at our Pioneer complex are transported on our Mid-America Pipeline System and ultimately to our Hobbs and Mont Belvieu NGL fractionators.

In late March 2008, operations at our Pioneer cryogenic natural gas processing facility were temporarily suspended following a release of natural gas and subsequent fire. No injuries resulted from the incident, which was restricted to a small area within the plant. The facility resumed operations in April 2008.

Results of Operations

We have four reportable business segments: NGL Pipelines & Services, Onshore Natural Gas Pipelines & Services, Offshore Pipelines & Services and Petrochemical Services. Our business segments are generally organized and managed according to the type of services rendered (or technologies employed) and products produced and/or sold.

We evaluate segment performance based on the non-GAAP financial measure of gross operating margin. Gross operating margin (either in total or by individual segment) is an important performance measure of the core profitability of our operations. This measure forms the basis of our internal financial reporting and is used by senior management in deciding how to allocate capital resources among business segments. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating segment results. The GAAP financial measure most directly comparable to total segment gross operating margin is operating income. Our non-GAAP financial measure of total segment gross operating margin should not be considered as an alternative to GAAP operating income.

We define total segment gross operating margin as consolidated operating income before (i) depreciation, amortization and accretion expense; (ii) operating lease expenses for which we do not have the payment obligation; (iii) gains and losses from asset sales and related transactions; and (iv) general and administrative costs. Gross operating margin is exclusive of other income and expense transactions, provision for income taxes, minority interest, extraordinary charges and the cumulative effect of changes in accounting principle. Gross operating margin by segment is calculated by subtracting segment operating costs and expenses (net of the adjustments noted above) from segment revenues, with both segment totals before the elimination of intersegment and intrasegment transactions. Intercompany accounts and transactions are eliminated in consolidation.

We include equity earnings from unconsolidated affiliates in our measurement of segment gross operating margin and operating income. Our equity investments with industry partners are a vital component of our business strategy. They are a means by which we conduct our operations to align our interests with those of our customers and/or suppliers. This method of operation also enables us to achieve favorable economies of scale relative to the level of investment and business risk assumed versus what we could accomplish on a stand-alone basis. Many of these businesses perform supporting or complementary roles to our other business operations.

Our consolidated gross operating margin amounts include the gross operating margin amounts of Duncan Energy Partners on a 100% basis. Volumetric data associated with the operations of Duncan Energy Partners are also included on a 100% basis in our consolidated statistical data.

For additional information regarding our business segments, see Note 12 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this Quarterly Report.

Selected Price and Volumetric Data

The following table illustrates selected quarterly industry index prices for natural gas, crude oil and selected NGL and petrochemical products for the periods presented.

	Natural Gas, $/MMBtu (1)	Crude Oil, $/barrel (2)	Ethane, $/gallon (1)	Propane, $/gallon (1)	Normal Butane, $/gallon (1)	Isobutane, $/gallon (1)	Natural Gasoline, $/gallon (1)	Polymer Grade Propylene, $/pound (1)	Refinery Grade Propylene, $/pound (1)
2007									
1st Quarter	$6.77	$58.02	$0.59	$0.97	$1.13	$1.22	$1.37	$0.45	$0.40
2nd Quarter	$7.55	$64.97	$0.72	$1.13	$1.33	$1.45	$1.65	$0.51	$0.46
3rd Quarter	$6.16	$75.48	$0.82	$1.23	$1.44	$1.49	$1.68	$0.52	$0.46
4th Quarter	$6.97	$90.75	$1.04	$1.51	$1.79	$1.80	$2.01	$0.59	$0.54
2007 Averages	$6.86	$72.30	$0.79	$1.21	$1.42	$1.49	$1.68	$0.52	$0.47
2008									
1st Quarter	$8.03	$97.91	$1.01	$1.47	$1.80	$1.87	$2.12	$0.61	$0.54
2nd Quarter	$10.94	$123.88	$1.05	$1.70	$2.05	$2.08	$2.64	$0.70	$0.67
3rd Quarter	$10.25	$118.01	$1.09	$1.68	$1.97	$1.99	$2.52	$0.78	$0.66
2008 Averages	$9.74	$113.27	$1.05	$1.62	$1.94	$1.98	$2.43	$0.70	$0.62

(1) Natural gas, NGL, polymer grade propylene and refinery grade propylene prices represent an average of various commercial index prices including Oil Price Information Service ("OPIS") and Chemical Market Associates, Inc. ("CMAI"). Natural gas price is representative of Henry-Hub I-FERC. NGL prices are representative of Mont Belvieu Non-TET pricing. Refinery grade propylene represents a weighted-average of CMAI spot prices. Polymer-grade propylene represents average CMAI contract pricing.
(2) Crude oil price is representative of an index price for West Texas Intermediate.

The following table presents our significant average throughput, production and processing volumetric data. These statistics are reported on a net basis, taking into account our ownership interests in certain joint ventures, and reflect the periods in which we owned an interest in such operations. These statistics include volumes for newly constructed assets since the dates such assets were placed into service and for recently purchased assets since the date of acquisition.

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2008	2007	2008	2007
NGL Pipelines & Services, net:				
NGL transportation volumes (MBPD)	1,758	1,575	1,788	1,626
NGL fractionation volumes (MBPD)	413	371	424	379
Equity NGL production (MBPD)	109	64	108	67
Fee-based natural gas processing (MMcf/d)	2,064	2,269	2,469	2,358
Onshore Natural Gas Pipelines & Services, net:				
Natural gas transportation volumes (BBtus/d)	7,562	6,597	7,309	6,576
Offshore Pipelines & Services, net:				
Natural gas transportation volumes (BBtus/d)	1,244	1,271	1,449	1,407
Crude oil transportation volumes (MBPD)	147	163	190	164
Platform gas processing (MMcf/d)	583	246	588	265
Platform oil processing (MBPD)	14	24	19	24
Petrochemical Services, net:				
Butane isomerization volumes (MBPD)	71	96	85	93
Propylene fractionation volumes (MBPD)	58	68	59	69
Octane additive production volumes (MBPD)	8	11	9	9
Petrochemical transportation volumes (MBPD)	95	108	110	104
Total, net:				
NGL, crude oil and petrochemical transportation volumes (MBPD)	2,000	1,846	2,088	1,894
Natural gas transportation volumes (BBtus/d)	8,806	7,868	8,758	7,983
Equivalent transportation volumes (MBPD) (1)	4,317	3,917	4,393	3,995

(1) Reflects equivalent energy volumes where 3.8 MMBtus of natural gas are equivalent to one barrel of NGLs.

Comparison of Results of Operations

The following table summarizes the key components of our results of operations for the periods indicated (dollars in thousands):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2008	2007	2008	2007
Revenues	$ 6,297,902	$ 4,111,996	$ 18,322,052	$ 11,647,656
Operating costs and expenses	5,971,942	3,896,411	17,243,070	10,981,562
General and administrative costs	21,720	18,715	66,901	66,706
Equity in earnings of unconsolidated affiliates	14,876	13,960	48,037	13,928
Operating income	319,116	210,830	1,060,118	613,316
Interest expense	102,657	85,075	290,412	219,708
Net income	203,081	117,606	725,960	371,805

Our gross operating margin by segment and in total is as follows for the periods indicated (dollars in thousands):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2008	2007	2008	2007
Gross operating margin by segment:				
NGL Pipelines & Services	$ 336,054	$ 190,209	$ 943,445	$ 589,708
Onshore Natural Gas Pipelines & Services	88,160	75,424	321,237	235,102
Offshore Pipelines & Services	17,465	46,676	134,353	97,429
Petrochemical Services	37,243	51,412	136,465	139,329
Total segment gross operating margin	$ 478,922	$ 363,721	$ 1,535,500	$ 1,061,568

For a reconciliation of non-GAAP gross operating margin to GAAP operating income and further to GAAP income before provision for income taxes and minority interest, see “Other Items – Non-GAAP reconciliations” included within this Item 2.

The following table summarizes the contribution to consolidated revenues from the sale of NGL, natural gas and petrochemical products during the periods indicated (dollars in thousands):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2008	2007	2008	2007
NGL Pipelines & Services:				
Sale of NGL products	$ 4,271,467	$ 2,837,465	$ 12,550,220	$ 7,952,147
Percent of consolidated revenues	68%	69%	68%	68%
Onshore Natural Gas Pipelines & Services:				
Sale of natural gas	851,748	406,482	2,407,930	1,190,235
Percent of consolidated revenues	14%	10%	13%	10%
Petrochemical Services:				
Sale of petrochemical products	708,745	444,670	1,928,840	1,268,731
Percent of consolidated revenues	11%	11%	11%	11%

As noted in the following section, changes in our revenues and costs and expenses period-to-period are explained in part by changes in energy commodity prices.

Comparison of Three Months Ended September 30, 2008 with Three Months Ended September 30, 2007

Revenues for the third quarter of 2008 were $6.30 billion compared to $4.11 billion for the third quarter of 2007. The $2.19 billion quarter-to-quarter increase in consolidated revenues is primarily due to higher energy commodity sales volumes and prices during the third quarter of 2008 relative to the third quarter of 2007. These factors accounted for $1.89 billion of the quarter-to-quarter increase in consolidated revenues associated with our NGL, natural gas and petrochemical marketing activities. Consolidated revenues increased $270.1 million quarter-to-quarter due to the addition of revenues from newly constructed assets, principally our Meeker and Pioneer natural gas processing plants.

Operating costs and expenses were $5.97 billion for the third quarter of 2008 versus $3.90 billion for the third quarter of 2007. The $2.07 billion quarter-to-quarter increase in consolidated operating costs and expenses is primarily due to higher cost of sales associated with our marketing activities. The cost of sales of our marketing activities increased $1.61 billion quarter-to-quarter primarily due to higher energy commodity sales volumes and prices. Likewise, the operating costs and expenses of our natural gas processing plants increased $294.5 million quarter-to-quarter primarily due to higher energy commodity prices. Consolidated operating costs and expenses attributable to newly constructed assets increased $92.6 million quarter-to-quarter. General and administrative costs increased $3.0 million quarter-to-quarter.

Changes in our revenues and costs and expenses quarter-to-quarter are explained in part by changes in energy commodity prices. The weighted-average indicative market price for NGLs was $1.68 per gallon during the third quarter of 2008 versus $1.21 per gallon during the third quarter of 2007. Our determination of the weighted-average indicative market price for NGLs is based on U.S. Gulf Coast prices for such products at Mont Belvieu, Texas, which is the primary industry hub for domestic NGL production. The market price of natural gas (as measured at Henry Hub) averaged $10.25 per MMBtu during the third quarter of 2008 versus $6.16 per MMBtu during the third quarter of 2007. See the table on page 55 for additional historical energy commodity pricing information.

Equity earnings from our unconsolidated affiliates were $14.9 million for the third quarter of 2008 compared to $14.0 million for the third quarter of 2007. Equity earnings from our investment in Jonah Gas Gathering Company ("Jonah") increased $2.9 million quarter-to-quarter. Equity earnings from our investment in Cameron Highway Oil Pipeline Company ("Cameron Highway") increased $1.9 million quarter-to-quarter due to higher transportation volumes. Collectively, equity earnings from our investments in Poseidon Oil Pipeline Company, L.L.C ("Poseidon") and Deepwater Gateway, L.L.C. ("Deepwater Gateway") decreased $4.1 million quarter-to-quarter as a result of downtime and upstream supply interruptions caused by Hurricanes Gustav and Ike during the third quarter of 2008.

Operating income for the third quarter of 2008 was $319.1 million compared to $210.8 million for the third quarter of 2007. Collectively, the aforementioned changes in revenues, costs and expenses and equity earnings contributed to the $108.3 million increase in operating income quarter-to-quarter.

Interest expense increased to $102.7 million for the third quarter of 2008 from $85.1 million for the third quarter of 2007. The $17.6 million quarter-to-quarter increase in interest expense is primarily due to our issuance of Senior Notes M and N in the second quarter of 2008 and Senior Notes L in the third quarter of 2007. Average debt principal outstanding during the third quarter of 2008 was $8.14 billion compared to $6.55 billion during the third quarter of 2007. Provision for income taxes increased $4.5 million quarter-to-quarter primarily due to higher expenses associated with the Texas Margin Tax.

As a result of items noted in the previous paragraphs, our consolidated net income increased $85.5 million quarter-to-quarter to $203.1 million for the third quarter of 2008 compared to $117.6 million for the third quarter of 2007.

In general, Hurricanes Gustav and Ike had an adverse effect across our operations in the Gulf of Mexico and along the U.S. Gulf Coast during the third quarter of 2008. Storm-related disruptions in natural gas, NGL and crude oil production in these regions resulted in reduced volumes available to our pipeline systems, natural gas processing plants, NGL fractionators and offshore platforms, which in turn caused a decrease in gross operating margin for certain operations. In addition, property damage caused by Hurricanes Gustav and Ike resulted in lower revenues due to facility downtime as well as higher operating costs and expenses at certain of our plants and pipelines. As a result of our allocated share of EPCO's insurance deductibles for windstorm coverage, gross operating margin for the third quarter of 2008 includes $46.0 million of repair expenses for property damage sustained by our assets as a result of the hurricanes.

We estimate that gross operating margin was reduced by $43.0 million during the third quarter of 2008 due to the effects of Hurricanes Gustav and Ike as a result of supply interruptions and facility downtime. We currently estimate the effects of lost business attributable to Hurricanes Gustav and Ike to reduce gross operating margin for the fourth quarter of 2008 by $25.0 million to $35.0 million prior to any future recoveries under business interruption insurance. For more information regarding our insurance program and claims related to these storms, see "Other Items – Weather-related Risks" included within this Item 2.

The following information highlights significant quarter-to-quarter variances in gross operating margin by business segment:

NGL Pipelines & Services. Gross operating margin from this business segment was $336.1 million for the third quarter of 2008 compared to $190.2 million for the third quarter of 2007. The $145.9 million quarter-to-quarter increase in segment gross operating margin is due to strong natural gas processing margins and NGL demand for petrochemical production as well as an increase in equity NGL production attributable to our Meeker and Pioneer natural gas processing facilities. The third quarter of 2007 includes $1.8 million of proceeds from business interruption insurance claims compared to none for the third quarter of 2008. The following paragraphs provide a discussion of segment results excluding proceeds from business interruption insurance claims.

Gross operating margin from our natural gas processing and related NGL marketing business was $237.6 million for the third quarter of 2008 compared to $96.1 million for the third quarter of 2007. Equity NGL production increased to 109 MBPD during the third quarter of 2008 from 64 MBPD during the third quarter of 2007. The $141.5 million quarter-to-quarter increase in gross operating margin is largely due to contributions from our Meeker and Pioneer cryogenic natural gas processing facilities, which commenced commercial operations during October 2007 and February 2008, respectively. These facilities contributed $97.8 million of the quarter-to-quarter increase in gross operating margin and produced 55 MBPD of equity NGLs during the third quarter of 2008. Gross operating margin from our NGL marketing activities increased $45.5 million quarter-to-quarter primarily due to higher NGL sales margins and volumes. Equity NGL production at the Meeker and Pioneer facilities contributed to the increase in NGL marketing sales volumes.

Collectively, gross operating margin from the remainder of this business decreased $1.8 million quarter-to-quarter. Higher natural gas processing margins in South Texas during the third quarter of 2008 relative to the third quarter of 2007 were more than offset by lower gross operating margin from our facilities in Southern Louisiana. Our natural gas processing plants in Louisiana were negatively affected by downtime and upstream supply interruptions as a result of Hurricanes Gustav and Ike in the third quarter of 2008. In addition, results for our natural gas processing plants in Southern Louisiana include $7.5 million of hurricane-related property damage repair expenses in the third quarter of 2008.

Gross operating margin from our NGL pipelines and related storage business was $72.5 million for the third quarter of 2008 compared to $71.2 million for the third quarter of 2007. Total NGL transportation volumes increased to 1,758 MBPD during the third quarter of 2008 from 1,575 MBPD during the third quarter of 2007. The $1.3 million quarter-to-quarter increase in gross operating margin from this business is primarily due to improved results from our Mid-America and Seminole Pipeline Systems and our NGL storage facility in Mont Belvieu, Texas. Gross operating margin from our Mid-America and Seminole Pipeline Systems increased $6.1 million quarter-to-quarter due to higher transportation volumes and an increase in the system-wide tariff. These pipeline systems contributed 138 MBPD of the quarter-to-quarter increase in NGL transportation volumes. Gross operating margin from our Mont Belvieu NGL storage facility increased $4.3 million as a result of higher revenues during the third quarter of 2008 relative to the third quarter of 2007.

Gross operating margin from the remainder of our NGL pipeline and storage assets decreased $9.1 million quarter-to-quarter attributable to (i) higher maintenance expenses on our Dixie Pipeline System and our NGL Export facility, (ii) higher pipeline integrity expenses on our Dixie Pipeline System and (iii) downtime and reduced volumes as a result of Hurricanes Gustav and Ike during the third quarter of 2008.

Gross operating margin from our Dixie Pipeline System and NGL Export facility decreased $4.0 million and $2.2 million quarter-to-quarter, respectively. In addition, results for our NGL pipelines and related storage business include $1.9 million of hurricane-related property damage repair expenses in the third quarter of 2008.

Gross operating margin from our NGL fractionation business was $25.9 million for the third quarter of 2008 compared to $21.1 million for the third quarter of 2007. Fractionation volumes increased from 371 MBPD during the third quarter of 2007 to 413 MBPD during the third quarter of 2008. The $4.8 million quarter-to-quarter increase in gross operating margin and 42 MBPD increase in fractionation volumes is largely attributable to our Hobbs fractionator, which became operational in August 2007. Gross operating margin from our Hobbs fractionator increased $9.3 million quarter-to-quarter on a 52 MBPD increase in NGL fractionation volumes. Collectively, gross operating margin from our other NGL fractionators decreased $4.5 million quarter-to-quarter primarily due to downtime and lower volumes at our Norco, Mont Belvieu and Baton Rouge fractionators as well as a combined $0.5 million of hurricane- related property damage repair expenses in the third quarter of 2008.

Onshore Natural Gas Pipelines & Services. Gross operating margin from this business segment was $88.2 million for the third quarter of 2008 compared to $75.4 million for the third quarter of 2007. Our onshore natural gas transportation volumes were 7,562 BBtus/d during the third quarter of 2008 compared to 6,597 BBtus/d during the third quarter of 2007. Gross operating margin from our onshore natural gas pipeline and related natural gas marketing business was $77.4 million in the third quarter of 2008 compared to $67.8 million in the third quarter of 2007. The $9.6 million quarter-to-quarter increase in gross operating margin from this business is largely due to improved results from our San Juan Gathering System. Gross operating margin on our San Juan Gathering System increased $16.7 million quarter-to-quarter due to higher revenues from transportation fees indexed to natural gas prices and condensate sales. Collectively, gross operating margin from the remainder of our natural gas pipelines increased $10.5 million quarter-to-quarter primarily due to (i) higher transportation volumes and fees on our Texas Intrastate System, (ii) an increase in volumes on our Piceance Creek Gathering System and (iii) increased equity earnings from our investment in Jonah. Results from our natural gas pipelines were partially offset by a $17.6 million quarter-to-quarter decrease in gross operating margin associated with our natural gas marketing activities primarily due to non-cash mark-to-market related charges that are expected to be recouped in cash in future periods extending through 2009.

Gross operating margin from our natural gas storage business was $10.7 million in the third quarter of 2008 compared to $7.6 million in the third quarter of 2007. The $3.1 million quarter-to-quarter increase in gross operating margin is primarily due to increased storage activity at our Petal natural gas storage facility. We placed an additional natural gas storage cavern having 4.2 Bcf of subscribed capacity in operation at the Petal facility during the third quarter of 2008. In addition, results from our Wilson natural gas storage facility in Texas improved quarter-to-quarter as we continue the progress of restoring commercial operations at this facility. Our Wilson facility has been under repairs during most of 2007 and 2008.

Offshore Pipelines & Services. Gross operating margin from this business segment was $17.5 million for the third quarter of 2008 compared to $46.7 million for the third quarter of 2007. The third quarter of 2007 includes $0.2 million of proceeds from business interruption insurance claims compared to none for the third quarter of 2008. The following paragraphs provide a discussion of segment results excluding proceeds from business interruption insurance claims.

Gross operating margin from our offshore platform services business was $34.5 million for the third quarter of 2008 compared to $28.8 million for the third quarter of 2007. The $5.7 million quarter-to-quarter increase in gross operating margin from this business is largely due to contributions from our Independence Hub platform. Gross operating margin from our Independence Hub platform increased $11.1 million quarter-to-quarter due to an increase in processing revenues. Collectively, gross operating margin from our other platforms and related assets decreased $5.4 million quarter-to-quarter primarily due to lower demand fees and a decline in volumes on our Falcon platform as well as lower volumes at all of our platforms due to hurricane-related disruptions in the third quarter of 2008. This includes $2.7 million of property damage repair expenses in the third quarter of 2008.

Gross operating margin from our offshore crude oil pipeline business was $5.7 million for the third quarter of 2008 compared to $8.9 million for the third quarter of 2007. Offshore crude oil transportation volumes decreased to 147 MBPD during the third quarter of 2008 from 163 MBPD during the third quarter of 2007. The $3.2 million quarter-to-quarter decrease in gross operating margin and 16 MBPD decrease in volumes from this business are primarily due to downtime and upstream volume disruptions as a result of Hurricanes Gustav and Ike in the third quarter of 2008. The quarter-to-quarter decrease in gross operating margin also reflects $0.7 million of hurricane-related property damage repair expenses in the third quarter of 2008.

Gross operating margin from our offshore natural gas pipeline business was a loss of $22.8 million for the third quarter of 2008 compared to $8.8 million of earnings for the third quarter of 2007. Our offshore natural gas transportation volumes were 1,244 BBtus/d during the third quarter of 2008 compared to 1,271 BBtus/d during the third quarter of 2007. The $31.6 million quarter-to-quarter decrease in gross operating margin from this business is primarily due to downtime, reduced volumes and property damage resulting from Hurricanes Gustav and Ike. Results for the third quarter of 2008 from this business include $32.1 million of hurricane-related property damage repair expenses. The effects of Hurricanes Gustav and Ike on this business were partially offset by a $10.1 million increase in gross operating margin from our Independence Trail Pipeline. The Independence Trail Pipeline benefited from a 499 BBtus/d quarter-to-quarter increase in transportation volumes.

Petrochemical Services. Gross operating margin from this business segment was $37.2 million for the third quarter of 2008 compared to $51.4 million for the third quarter of 2007. Gross operating margin from our propylene fractionation and pipeline business was $31.0 million for the third quarter of 2008 compared to $14.0 million for the third quarter of 2007. The $17.0 million quarter-to-quarter increase in gross operating margin is largely due to higher propylene sales margins during the third quarter of 2008 relative to the third quarter of 2007. Results for our propylene fractionation and related pipeline business for the third quarter of 2008 include $0.4 million of hurricane-related property damage repair expenses.

Gross operating margin from our octane enhancement business was a loss of $12.9 million for the third quarter of 2008 compared to $8.9 million of earnings for the third quarter of 2007. The $21.8 million quarter-to-quarter decrease in gross operating margin from this business is primarily due to downtime, reduced volumes and higher operating expenses as a result of operational issues during the third quarter of 2008 and the effects of Hurricane Ike. Gross operating margin from our butane isomerization business was $19.1 million for the third quarter of 2008 compared to $28.5 million for the third quarter of 2007. The $9.4 million quarter-to-quarter decrease in gross operating margin from this business is primarily due to reduced demand for isobutane from our octane enhancement facility due to operational issues in the third quarter of 2008 and downtime related to Hurricane Ike.

Comparison of Nine Months Ended September 30, 2008 with Nine Months Ended September 30, 2007

Revenues for the first nine months of 2008 were $18.32 billion compared to $11.65 billion for the first nine months of 2007. The $6.67 billion period-to-period increase in consolidated revenues is primarily due to higher energy commodity sales volumes and prices during the first nine months of 2008 relative to the first nine months of 2007. These factors accounted for $5.88 billion of the period-to-period increase in consolidated revenues associated with our NGL, natural gas and petrochemical marketing activities. Consolidated revenues increased $684.7 million period-to-period due to the addition of revenues from newly constructed assets, principally our Meeker and Pioneer natural gas processing plants and our Independence Hub and Trail projects.

Operating costs and expenses were $17.24 billion for the first nine months of 2008 compared to $10.98 billion for the first nine months of 2007. The $6.26 billion period-to-period increase in consolidated operating costs and expenses is primarily due to higher costs of sales associated with our marketing activities. The cost of sales of our natural gas, NGL and petrochemical products increased $5.10 billion period-to-period primarily due to higher energy commodity sales volumes and prices. Operating costs and expenses associated with our natural gas processing plants increased $736.8 million period-to-period as a result of higher energy commodity prices and processing volumes during the first nine months of 2008 compared to the first nine months of 2007. Consolidated operating costs and expenses attributable to newly constructed assets increased $345.1 million period-to-period.

Changes in our revenues and costs and expenses period-to-period are explained in part by changes in energy commodity prices. The weighted-average indicative market price for NGLs was $1.62 per gallon for the nine months ended September 30, 2008 versus $1.09 per gallon during the nine months ended September 30, 2007. The Henry Hub market price for natural gas averaged $9.74 per MMBtu for the first nine months of 2008 versus $6.83 per MMBtu during the first nine months of 2007. For additional historical energy commodity pricing information, please see the table on page 55.

Equity earnings from our unconsolidated affiliates were $48.0 million for the first nine months of 2008 compared to $13.9 million for the first nine months of 2007, a period-to-period increase of $34.1 million. Equity earnings from our investment in Cameron Highway increased $26.3 million period-to-period due to higher transportation volumes and lower interest expense. On a 100% basis, Cameron Highway had crude oil transportation volumes of 171 MBPD during the first nine months of 2008 compared to 84 MBPD during the first nine months of 2007. Equity earnings from our investment in Jonah increased $11.7 million period-to-period. We earned a fixed 19.4% interest in Jonah during the third quarter of 2007 upon completion of certain achievements with respect to the Phase V Expansion of the Jonah Gathering System. Equity earnings from our investment in Nemo Gathering Company, LLC ("Nemo") increased $5.7 million period-to-period due to the recognition of a non-cash impairment charge in the second quarter of 2007. Collectively, equity earnings from our other investments decreased $9.6 million period-to-period due to higher repair and maintenance expenses during the first nine months of 2008 relative to the first nine months of 2007 as well as the effects of downtime and reduced volumes attributable to Hurricanes Gustav and Ike.

Operating income for the first nine months of 2008 was $1.06 billion compared to $613.3 million for the first nine months of 2007. Collectively, the aforementioned changes in revenues, costs and expenses and equity earnings contributed to the $446.8 million increase in operating income period-to-period.

Interest expense increased to $290.4 million for the first nine months of 2008 from $219.7 million for the first nine months of 2007. The $70.7 million period-to-period increase in interest expense is attributable to a higher average balance of debt principal outstanding. Our average debt principal outstanding was $7.65 billion for the first nine months of 2008 compared to $5.95 billion for the first nine months of 2007. We issued Senior Notes L in the third quarter of 2007, Senior Notes M and N in the second quarter of 2008 and Junior Subordinated Notes B in the third quarter of 2007.

Provision for income taxes increased $8.2 million period-to-period primarily due to the recognition of a $4.4 million benefit with respect to the Texas Margin Tax in the second quarter of 2007 and higher expenses associated with the Texas Margin Tax during the first nine months of 2008. The benefit was associated with a reorganization of certain of our entities from partnerships to limited liability companies effective September 30, 2007. Minority interest expense increased $10.1 million period-to-period attributable to the public unitholders of Duncan Energy Partners and third-party ownership interests in the Independence Hub platform.

As a result of the items noted in previous paragraphs, our consolidated net income increased $354.2 million to $726.0 million for the nine months ended September 30, 2008 compared to $371.8 million for the first nine months of 2007.

The following information highlights the significant period-to-period variances in gross operating margin by business segment:

NGL Pipelines & Services. Gross operating margin from this business segment was $943.4 million for the first nine months of 2008 compared to $589.7 million for the first nine months of 2007, a period-to-period increase of $353.7 million. The first nine months of 2008 include $1.1 million of proceeds from business interruption insurance claims compared to $23.4 million of proceeds during the first nine months of 2007. The following paragraphs provide a discussion of segment results excluding proceeds from business interruption insurance claims.

Gross operating margin from our natural gas processing and related NGL marketing business was $611.8 million for the first nine months of 2008 compared to $283.5 million for the first nine months of 2007. The $328.3 million period-to-period increase in gross operating margin is largely due to higher natural gas processing margins and volumes and increased equity NGL production during the first nine months of 2008 relative to the first nine months of 2007. Total fee-based processing volumes increased to 2.5 Bcf/d during the first nine months of 2008 from 2.4 Bcf/d during the first nine months of 2007. Likewise, equity NGL production increased to 108 MBPD during the first nine months of 2008 from 67 MBPD during the first nine months of 2007.

Collectively, gross operating margin from our Meeker and Pioneer facilities increased $203.3 million period-to-period on a 47 MBPD increase in equity NGL production. Gross operating margin from our NGL marketing activities increased $70.3 million period-to-period primarily due to higher NGL sales margins and volumes. This business also benefited from improved natural gas processing margins in South Texas and the Permian Basin during the first nine months of 2008 relative to the first nine months of 2007. Gross operating margin from our South Texas processing plants and Chaco facility experienced a period-to-period increase of $41.3 million and $23.0 million, respectively. Collectively, gross operating margin from the remainder of our natural gas processing facilities decreased $9.7 million period-to-period primarily due to downtime, reduced volumes and property damage repair expenses affecting our Southern Louisiana natural gas processing plants as a result of Hurricanes Gustav and Ike.

Gross operating margin from our NGL pipelines and related storage business was $252.8 million for the first nine months of 2008 compared to $215.5 million for the first nine months of 2007. Total NGL transportation volumes increased to 1,788 MBPD during the first nine months of 2008 from 1,626 MBPD during the first nine months of 2007. The $37.3 million period-to-period increase in gross operating margin and 162 MBPD increase in transportation volumes from this business is primarily due to higher NGL transportation volumes and a system-wide tariff increase on our Mid-America Pipeline System.

Gross operating margin from our NGL fractionation business was $77.7 million for the first nine months of 2008 compared to $67.3 million for the first nine months of 2007. Fractionation volumes were 424 MBPD during the first nine months of 2008 compared to 379 MBPD during the first nine months of 2007. The $10.4 million period-to-period increase in gross operating margin and 45 MBPD increase in fractionation volumes is primarily due to contributions from our Hobbs fractionator. Gross operating margin from our Hobbs fractionator increased $23.1 million period-to-period on a 53 MBPD increase in NGL fractionation volumes. Collectively, gross operating margin from our other NGL fractionators decreased $12.7 million period-to-period primarily due to lower volumes at our Mont Belvieu and Norco fractionators. Our Mont Belvieu fractionator experienced downtime during the first quarter of 2008 for scheduled maintenance activities. Also, our Mont Belvieu and Norco fractionators experienced downtime and reduced volumes in the third quarter of 2008 due to the effects of Hurricanes Gustav and Ike.

Onshore Natural Gas Pipelines & Services. Gross operating margin from this business segment was $321.2 million for the first nine months of 2008 compared to $235.1 million for the first nine months of 2007. Our onshore natural gas transportation volumes were 7,309 BBtus/d during the first nine months of 2008 compared to 6,576 BBtus/d during the first nine months of 2007. Gross operating margin from our onshore natural gas pipeline and related natural gas marketing business was $292.2 million for the first nine months of 2008 compared to $216.2 million for the first nine months of 2007. Collectively, gross operating margin from our natural gas pipelines increased $93.1 million period-to-period primarily due to (i) higher revenues from our San Juan Gathering System, (ii) higher transportation activity on our Texas Intrastate System, (iii) higher natural gas sales margins on our Acadian Gas System and (iv) increased equity earnings from our investment in Jonah.

Gross operating margin from our natural gas storage business was $29.0 million for the first nine months of 2008 compared to $18.9 million for the first nine months of 2007. The $10.1 million period-to-period increase in gross operating margin is primarily due to increased storage activity at our Petal natural gas storage facility and improved results at our Wilson facility. We placed additional natural gas storage caverns in operation during the third quarters of 2007 and 2008 at the Petal facility, which provided an additional 1.6 Bcf and 4.2 Bcf of subscribed capacity, respectively.

Gross operating margin from our natural gas marketing activities decreased $17.1 million period-to-period primarily due to non-cash mark-to-market related charges that are expected to be recouped in cash in future periods extending through 2009. Our natural gas marketing business has increased significantly during 2008. These marketing activities have four primary objectives: (i) to mitigate risk; (ii) maximize the use of our natural gas assets; (iii) to provide real-time market intelligence; and (iv) to link our noncontiguous natural gas assets together to enhance the profitability of such operations. To achieve these objectives, our natural gas marketing activities transact with various parties to provide transportation, balancing, storage, supply and sales services. The majority of our natural gas marketing activities are focused on the Gulf Coast and Rocky Mountain regions.

Our natural gas marketing business acquires a significant portion of the natural gas it sells from our processing plants and attracts additional supplies from third parties at pipeline interconnects to facilitate incremental throughput on our natural gas transportation pipelines. This purchased gas is then sold to industrial consumers, utilities and power plants at prices that include a transportation fee. In addition, sales are made with third party marketing companies at industry hub locations in order to balance our supply/demand portfolio. Our purchase and sale transactions are typically based on published daily or monthly index prices. We utilize financial instruments to hedge various transactions within our natural gas marketing business.

We use third party transportation and storage capacity to link together our non-contiguous natural gas assets. Our natural gas marketing business contracts with third party transportation and storage providers to provide services on both a firm and interruptible basis. This strategy allows us to compliment and strengthen our portfolio of natural gas assets.

Offshore Pipelines & Services. Gross operating margin from this business segment was $134.4 million for the first nine months of 2008 compared to $97.4 million for the first nine months of 2007. The $37.0 million period-to-period increase in segment gross operating margin is primarily due to contributions from our Independence Hub and Trail project and improved results from our Cameron Highway Oil Pipeline. Results from this business segment for the first nine months of 2008 were negatively impacted by (i) downtime and $17.0 million of repair expenses associated with a leak on the Independence Trail pipeline and (ii) the effects of Hurricanes Gustav and Ike including downtime, reduced volumes and $35.5 million of property damage repair expenses. The first nine months of 2008 include $0.2 million of proceeds from business interruption insurance claims compared to $1.5 million of proceeds during the first nine months of 2007. The following paragraphs provide a discussion of segment results excluding proceeds from business interruption insurance.

Gross operating margin from our offshore platform services business was $109.7 million for the first nine months of 2008 compared to $69.5 million for the first nine months of 2007. The $40.2 million period-to-period increase in gross operating margin is primarily due to our completion of the Independence Hub platform in March 2007. Gross operating margin increased period-to-period despite the platform being shut-in for 66 days during the second quarter of 2008 due to a leak on the Independence Trail export pipeline. While the Independence Hub platform did not earn volumetric fees during the period of suspended operations, the platform continued to earn its fixed demand revenues of approximately $5.0 million per month. Our net platform natural gas processing volumes increased to 588 MMcf/d during the first nine months of 2008 compared to 265 MMcf/d during the first nine months of 2007.

Gross operating margin from our offshore crude oil pipeline business was $32.7 million for the first nine months of 2008 versus $11.9 million for the first nine months of 2007. The $20.8 million period-to-period increase in gross operating margin is primarily due to increased equity earnings from Cameron Highway, which benefited from higher crude oil transportation volumes and lower interest expense in the first nine months of 2008 relative to the first nine months of 2007. Crude oil transportation volumes on the Cameron Highway Oil Pipeline System netted to our ownership interest were 85 MBPD in the first nine months of 2008 compared to 42 MBPD in the first nine months of 2007. Total offshore crude oil transportation volumes were 190 MBPD during the first nine months of 2008 versus 164 MBPD during the first nine months of 2007.

Gross operating margin from our offshore natural gas pipeline business was a loss of $8.3 million for the first nine months of 2008 compared to $14.6 million of earnings for the first nine months of 2007. Offshore natural gas transportation volumes were 1,449 BBtus/d during the first nine months of 2008 versus 1,407 BBtus/d during the first nine months of 2007. Gross operating margin from our Independence Trail pipeline, which first received production in July 2007, increased $24.1 million period-to-period on a 460 BBtus/d increase in transportation volumes. Collectively, gross operating margin from our other offshore natural gas pipelines decreased $47.0 million period-to-period primarily due to the effects of Hurricanes Gustav and Ike.

Petrochemical Services. Gross operating margin from this business segment was $136.5 million for the first nine months of 2008 compared to $139.3 million for the first nine months of 2007. Gross operating margin from our propylene fractionation business was $64.3 million for the first nine months of 2008 versus $45.6 million for the first nine months of 2007. The $18.7 million period-to-period increase in gross operating margin is largely due to higher propylene sales margins.

Gross operating margin from our butane isomerization business was $77.9 million for the first nine months of 2008 compared to $71.7 million for the first nine months of 2007. The $6.2 million period-to-period increase in gross operating margin is primarily due to strong demand for high-purity isobutane and higher NGL prices, which resulted in higher by-product sales revenues during the first nine months of 2008 relative to the first nine months of 2007. Butane isomerization volumes decreased to 85 MBPD during the first nine months of 2008 compared to 93 MBPD for the first nine months of 2007 due to production interruptions resulting from Hurricane Ike and operational issues at our octane enhancement facility during the third quarter of 2008.

Gross operating margin from our octane enhancement business was a loss of $5.7 million for the first nine months of 2008 compared to $22.1 million of earnings for the first nine months of 2007. The $27.8 million period-to-period decrease in gross operating margin is primarily due to downtime, reduced volumes and higher operating expenses as a result of operational issues during the third quarter of 2008 and the effects of Hurricane Ike.

Liquidity and Capital Resources

Our primary cash requirements, in addition to normal operating expenses and debt service, are for working capital, capital expenditures, business acquisitions and distributions to partners. We expect to fund our short-term needs for such items as operating expenses and sustaining capital expenditures with operating cash flows and short-term revolving credit arrangements. Capital expenditures for long-term needs resulting from business expansion projects and acquisitions are expected to be funded by a variety of sources (either separately or in combination) including net cash flows provided by operating activities, borrowings under credit facilities, the issuance of additional equity and debt securities and proceeds from divestitures of ownership interests in assets to affiliates or third parties. We expect to fund cash distributions to partners primarily with operating cash flows. Our debt service requirements are expected to be funded by operating cash flows and/or refinancing arrangements.

At September 30, 2008, we had $55.4 million of unrestricted cash on hand and approximately $539.3 million of available credit under EPO’s Multi-Year Revolving Credit Facility. We had approximately $8.43 billion in principal outstanding under consolidated debt agreements at September 30,

2008. In total, our consolidated liquidity at September 30, 2008 was approximately $730.0 million, which includes the available borrowing capacity of our consolidated subsidiaries such as Duncan Energy Partners.

Recent volatility in global capital markets has resulted in a significant increase in the costs of incremental debt and equity capital and has reduced the availability of debt and equity capital. We expect that the current cost of capital may trend lower in the coming months as coordinated government-led funding programs are implemented worldwide. As the capital markets begin to stabilize and recover, we believe that we will have sufficient access to debt and equity capital to support our operating and investing activities. Costs of such capital, however, may remain significantly higher for an extended period of time. Our disciplined approach to funding capital spending and other partnership needs, combined with sufficient trade credit to operate our businesses efficiently, available borrowing capacity under our consolidated credit facilities and retained distributable cash flow, should provide us with a foundation to meet our anticipated liquidity and capital resource requirements.

For information regarding our risks in connection with the global financial crisis, see "*The global financial crisis may have impacts on our business and financial condition that we currently cannot predict*," under Item 1A of Part II of this quarterly report on Form 10-Q.

For additional information regarding our growth strategy, see "Capital Spending" included within this Item 2.

Registration Statements

We may issue equity or debt securities to assist us in meeting our liquidity and capital spending requirements. We have a universal shelf registration statement on file with the SEC registering the issuance of an unlimited amount of equity and debt securities. In April 2008, EPO issued $1.10 billion in principal amount of fixed-rate, unsecured senior notes under this registration statement. Net proceeds from these senior note offerings were used to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility.

We also have on file with the SEC a registration statement authorizing the issuance of up to 25,000,000 common units in connection with our distribution reinvestment program ("DRIP"). The DRIP provides unitholders of record and beneficial owners of our common units a voluntary means by which they can increase the number of common units they own by reinvesting the quarterly cash distributions they would otherwise receive into the purchase of additional common units of our partnership. An aggregate of 1,895,776 of our common units were issued in connection with the DRIP and a related plan during the nine months ended September 30, 2008. The issuance of these units generated $56.5 million in net proceeds that we used for general partnership purposes. In November 2008, affiliates of EPCO expect to reinvest $67.0 million in connection with the DRIP.

In March 2008, Duncan Energy Partners filed a universal shelf registration statement with the SEC that authorized its issuance of up to $1.00 billion in debt and equity securities. Duncan Energy Partners has not issued any securities under this registration statement through November 3, 2008.

Letter of Credit Facility

During the third quarter of 2008, a $60.0 million letter of credit was issued under EPO's Multi-Year Revolving Credit Facility to support our NYMEX margin requirements for natural gas financial instruments that are part of an economic hedge related to our natural gas processing business. In October 2008, EPO entered into a $100.0 million letter of credit facility. EPO issued a $70.0 million letter of credit under this new facility that replaced the letter of credit issued under its Multi-Year Revolving Credit Facility which was outstanding at September 30, 2008.

Credit Ratings of EPO

At November 3, 2008, the investment grade credit ratings of EPO's senior unsecured debt securities were Baa3 by Moody's Investor Services and BBB- by Fitch Ratings and Standard and Poor's. Such ratings reflect only the view of the rating agency and should not be interpreted as a recommendation to buy, sell or hold our securities. These ratings may be revised or withdrawn at any time by the agencies at their discretion.

Cash Flows from Operating, Investing and Financing Activities

The following table summarizes our cash flows from operating, investing and financing activities for the periods indicated (dollars in thousands). For information regarding the individual components of our cash flow amounts, see our Unaudited Condensed Statements of Consolidated Cash Flows included under Item 1 of this Quarterly Report.

	For the Nine Months Ended September 30,	
	2008	**2007**
Net cash flows provided by operating activities	$ 973,044	$ 937,835
Cash used in investing activities	1,709,203	2,039,495
Cash provided by financing activities	751,820	1,122,575

Net cash flows provided by operating activities are largely dependent on earnings from our business activities. As a result, these cash flows are exposed to certain risks. We operate predominantly in the midstream energy industry. We provide services for producers and consumers of natural gas, NGLs, crude oil and certain petrochemicals. The products that we process, sell or transport are principally used as fuel for residential, agricultural and commercial heating; feedstocks in petrochemical manufacturing; and in the production of motor gasoline. Reduced demand for our services or products by industrial customers, whether because of a decline in general economic conditions, reduced demand for the end products made with our products, or increased competition from other service providers or producers due to pricing differences or other reasons, could have a negative impact on our earnings and operating cash flows.

We use the indirect method to compute net cash flows provided by operating activities. See Note 17 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this Quarterly Report for information regarding this method of presentation.

Cash used in investing activities primarily represents expenditures for additions to property, plant and equipment, business combinations and investments in unconsolidated affiliates. Cash provided by financing activities generally consists of borrowings and repayments of debt, distributions to partners and proceeds from the issuance of equity securities. Amounts presented in our Unaudited Condensed Statements of Consolidated Cash Flows for borrowings and repayments under debt agreements are influenced by the magnitude of cash receipts and payments under our revolving credit facilities.

The following information highlights the significant period-to-period variances in our cash flow amounts:

Comparison of Nine Months Ended September 30, 2008 with Nine Months Ended September 30, 2007

Operating Activities. Net cash flows provided by operating activities were $973.0 million for the nine months ended September 30, 2008 compared to $937.8 million for the nine months ended September 30, 2007. This $35.2 million increase in net cash flows provided by operating activities was primarily due to the following:

- Net cash flows from consolidated operations (excluding cash payments for interest) increased $130.6 million period-to-period. This improvement in operating cash flow is generally due to an increase in gross operating margin between periods (see "Results of Operations" included within this Item 2) adjusted for the timing of related cash receipts and disbursements.

- Cash payments for interest increased $112.9 million period-to-period primarily due to increased borrowings to finance our capital spending program and for general partnership purposes.

- Increased distributions received from unconsolidated affiliates of $17.5 million for the nine months ended September 30, 2008 compared to the nine months ended September 30, 2007 due primarily to improved operations and earnings at Jonah Gas Gathering Company ("Jonah").

Investing Activities. Cash used in investing activities was $1.71 billion for the nine months ended September 30, 2008 compared to $2.04 billion for the nine months ended September 30, 2007. This $330.3 million decrease in cash used in investing activities was primarily due to the following:

- Capital spending for property, plant and equipment, net of contributions in aid of construction, decreased $167.6 million period-to-period. For additional information related to our capital spending program, see "Capital Spending" included within this Item 2.

- Cash outlays for investments in unconsolidated affiliates decreased by $257.1 million period-to-period. During the second quarter of 2007, we contributed $216.5 million to an unconsolidated affiliate, Cameron Highway. In return, Cameron Highway used these funds, along with an equal contribution from our 50% joint venture partner in Cameron Highway, to repay $430.0 million in outstanding debt. In addition, cash contributions to Jonah decreased $50.0 million period-to-period as a result of the timing of construction expenditures related to the Jonah Phase V expansion, which was completed in June 2008. Also, in the second quarter of 2008 we acquired a 50% interest in White River Hub, LLC ("White River Hub") and have contributed cash of $10.0 million since its acquisition.

- A $32.7 million increase in restricted cash (a cash outflow) due to margin requirements related to financial instruments held in 2008 and proceeds held in connection with the Petal GO Zone bonds in 2007.

- An increase of $56.3 million in cash used for business combinations primarily relating to the acquisition of the remaining interest in Dixie in August 2008.

Financing Activities. Cash provided by financing activities was $751.8 million for the nine months ended September 30, 2008 compared to $1.12 billion for the nine months ended September 30, 2007. This $370.8 million decrease in cash provided by financing activities was primarily due to the following:

- Net borrowings under our consolidated debt agreements were $1.54 billion during the nine months ended September 30, 2008 compared to $1.47 billion during the nine months ended September 30, 2007. The $69.4 million increase was attributable to increased period-to-period borrowings to fund general partnership purposes.

- Cash distributions to our partners and minority interests increased $77.8 million period-to-period primarily due to an increase in our common units outstanding and quarterly distribution rates, and an increase in the quarterly distribution rates of Duncan Energy Partners.

- Contributions from minority interests decreased $302.9 million period-to-period due to the initial public offering of Duncan Energy Partners in February 2007, which generated proceeds of approximately $291.0 million.

- The early termination and settlement of interest rate hedging financial instruments during the first nine months of 2008 resulted in net cash payments of $22.1 million compared to net cash receipts of $48.9 million during the same period in 2007, causing a $71.0 million decrease in financing cash flows between periods.

Capital Spending

An integral part of our business strategy involves expansion through business combinations, growth capital projects and investments in joint ventures. We believe that we are positioned to continue to grow our system of assets through the construction of new facilities and to capitalize on expected increases in natural gas and/or crude oil production from resource basins such as the Piceance Basin of western Colorado, the Greater Green River Basin in Wyoming, the Barnett Shale in North Texas and the deepwater Gulf of Mexico.

Management continues to analyze potential acquisitions, joint ventures and similar transactions with businesses that operate in complementary markets or geographic regions. In past years, major oil and gas companies have sold non-strategic assets in the midstream energy sector in which we operate. We forecast that this trend will continue, and expect independent oil and natural gas companies to consider similar divestitures.

The following table summarizes our capital spending by activity on a cash basis for the periods indicated (dollars in thousands):

	For the Nine Months Ended September 30,	
	2008	**2007**
Capital spending for property, plant and equipment, net of contributions in aid of construction costs	$ 1,464,439	$ 1,631,993
Capital spending for business combinations	57,090	785
Capital spending for acquisition of intangible assets (1)	5,126	--
Capital spending for investments in unconsolidated affiliates (2)	35,307	318,491
Total capital spending	$ 1,561,962	$ 1,951,269

(1) Represents the acquisition of permits for our Mont Belvieu storage facility.
(2) Capital spending for the nine months ended September 30, 2007 includes $216.5 million in cash contributions to Cameron Highway to fund our share of the repayment of its debt obligations.

Based on information currently available, we estimate our consolidated capital spending for property, plant and equipment for the remainder of 2008 (i.e., the fourth quarter) will approximate $555.2 million, which includes estimated expenditures of $494.6 million for growth capital projects and $60.6 million for sustaining capital expenditures.

Our forecast of consolidated capital expenditures is based on our current announced strategic operating and growth plans, which are dependent upon our ability to generate the required funds from either operating cash flows or from other means, including borrowings under debt agreements, issuance of equity and potential divestitures of certain assets to third and/or related parties. Our forecast of capital expenditures may change due to factors beyond our control, such as weather related issues, changes in supplier prices or adverse economic conditions. Furthermore, our forecast may change as a result of decisions made by management at a later date, which may include acquisitions or decisions to take on additional partners.

Our success in raising capital, including the formation of joint ventures to share costs and risks, continues to be a principal factor that determines how much capital we can invest. We believe our access to capital resources is sufficient to meet the demands of our current and future operating growth needs, and although we currently intend to make the forecasted expenditures discussed above, we may adjust the timing and amounts of projected expenditures in response to changes in capital markets.

At September 30, 2008, we had approximately $541.2 million in purchase commitments outstanding that relate to our capital spending for property, plant and equipment. These commitments primarily relate to construction of our Barnett Shale natural gas pipeline project and Meeker natural gas processing plant expansion.

Spending Update Regarding Significant Ongoing Announced Growth Capital Projects

The following table summarizes information regarding selected significant announced growth capital projects (dollars in millions). Actual costs noted for each project reflects our share of cash expenditures as of September 30, 2008, excluding capitalized interest. The forecast amount noted for each project also reflects our share of project expenditures, excluding estimated capitalized interest.

Project Name	Estimated Date of Completion	Actual Costs	Current Forecast Total Cost
Mont Belvieu Storage Well Optimization Projects	Fourth Quarter 2008	$ 197.9	$ 235.4
Meeker II natural gas processing plant	Fourth Quarter 2008	372.2	451.8
ExxonMobil Conditioning & Treating Facility – Piceance Basin	Fourth Quarter 2008	164.5	184.6
Sherman Extension Pipeline (Barnett Shale)	2009	309.8	489.3
Shenzi Oil Pipeline	2009	121.4	160.1
Marathon Piceance Basin pipeline projects	2009	26.5	154.3
Trinity River Basin Extension	2009	--	232.6
Expansion of Wilson natural gas storage facility	2010	47.0	105.7
Texas Offshore Port System (TOPS and PACE)	2010	0.2	617.4

Pipeline Integrity Costs

Our NGL, petrochemical and natural gas pipelines are subject to pipeline safety programs administered by the U.S. Department of Transportation, through its Office of Pipeline Safety. The following table summarizes our pipeline integrity costs, net of indemnity payments received from El Paso, for the periods indicated (dollars in thousands):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2008	2007	2008	2007
Expensed	$ 14,556	$ 11,315	$ 38,396	$ 34,987
Capitalized	16,159	15,679	38,934	41,543
Total	$ 30,715	$ 26,994	$ 77,330	$ 76,530

We expect our cash outlay for the pipeline integrity program, irrespective of whether such costs are capitalized or expensed, to approximate $34.7 million for the remainder of 2008. This amount includes $2.7 million attributable to pipeline integrity projects of Duncan Energy Partners.

Overview of Critical Accounting Policies and Estimates

A summary of the significant accounting policies we have adopted and followed in the preparation of our consolidated financial statements is included in our Annual Report on Form 10-K for the year ended December 31, 2007. Certain of these accounting policies require the use of estimates. As more fully described therein, the following estimates, in our opinion, are subjective in nature, require the exercise of judgment and involve complex analysis: depreciation methods and estimated useful lives of property, plant and equipment; measuring recoverability of long-lived assets and equity method investments; amortization methods and estimated useful lives of qualifying intangible assets; methods we employ to measure the fair value of goodwill; revenue recognition policies and use of estimates for revenues and expenses; reserves for environmental matters; and natural gas imbalances. These estimates are based on our current knowledge and understanding and may change as a result of actions we may take in the future. Changes in these estimates will occur as a result of the passage of time and the occurrence of future events.

Subsequent changes in these estimates may have a significant impact on our financial position, results of operations and cash flows.

On a quarterly basis, we monitor the underlying business fundamentals of our investments in unconsolidated affiliates and test such investments for impairment when impairment indicators are present. As a result of our reviews for the third quarter of 2008, no impairment charges were required. We have the intent and ability to hold these investments, which are integral to our operations.

Other Items

Contractual Obligations

The following information summarizes significant changes in our contractual obligations since those presented in our Annual Report on Form 10-K at December 31, 2007 (dollars in thousands).

		Payment or Settlement due by Period			
Contractual Obligations	**Total**	**Less than 1 year**	**1-3 years**	**4-5 years**	**More than 5 years**
Scheduled maturities of long-term debt (1)	$ 8,434,201	$ --	$ 1,726,000	$ 1,900,701	$ 4,807,500
Estimated cash payments for interest (2)	$ 9,212,927	$ 488,865	$ 867,389	$ 723,280	$ 7,133,393
Purchase obligations:					
Product purchase commitments:					
Estimated payment obligations:					
Natural gas (3)	$ 5,707,213	$ 261,703	$ 985,430	$ 1,232,670	$ 3,227,410
Underlying volume commitment:					
Natural gas (in BBtus) (3)	927,765	45,360	158,775	199,505	524,125
Service payment commitments for pipeline capacity reservation (4)	$ 157,633	$ 2,730	$ 27,414	$ 30,074	$ 97,415

(1) Represents scheduled maturities of consolidated debt obligations at September 30, 2008. For additional information regarding or consolidated debt obligations, see Note 10 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this Quarterly Report.

(2) Our estimated cash payments for interest are based on the principle amount of consolidated debt obligations outstanding at September 30, 2008. With respect to variable-rate debt, we applied the weighted-average interest rates paid during the nine months ended September 30, 2008. With respect to fixed-rate debt, we applied the stated coupon rate of each debt instrument. Our estimate of cash payments for interest gives effect to interest rate swap agreements in place at September 30, 2008. In addition, our estimated cash payments are significantly influenced by the long-term maturities of our $550.0 million Junior Notes A (due August 2066) and $700.0 million Junior Notes B (due January 2068). Our estimated cash payments for interest assume that such subordinated debt obligations are not called prior to maturity.

(3) Reflects commitments associated with new natural gas purchase agreements executed during the second and third quarters of 2008 in connection with our natural gas marketing activities.

(4) Reflects commitments associated with a pipeline capacity reservation agreement executed during the third quarter of 2008 in connection with our natural gas marketing activities.

Off-Balance Sheet Arrangements

There have been no significant changes with regards to our off-balance sheet arrangements since those reported in our Annual Report on Form 10-K for the year ended December 31, 2007.

Summary of Related Party Transactions

The following table summarizes our revenue and expense transactions with related parties for the periods indicated (dollars in thousands).

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2008	2007	2008	2007
Revenues from consolidated operations:				
EPCO and affiliates	$ 47,215	$ 12,673	$ 91,922	$ 42,778
Energy Transfer Equity and subsidiaries	99,583	78,957	412,975	121,521
Unconsolidated affiliates	153,361	87,209	318,710	215,015
Total	$ 300,159	$ 178,839	$ 823,607	$ 379,314
Operating costs and expenses:				
EPCO and affiliates	$ 87,991	$ 72,296	$ 274,406	$ 219,879
Energy Transfer Equity and subsidiaries	56,528	2,614	134,447	8,385
Unconsolidated affiliates	20,688	6,414	68,214	22,628
Total	$ 165,207	$ 81,324	$ 477,067	$ 250,892
General and administrative costs:				
EPCO and affiliates	$ 13,403	$ 11,504	$ 44,631	$ 45,292
Unconsolidated affiliates	(37)	--	(37)	--
Total	$ 13,366	$ 11,504	$ 44,594	$ 45,292
Other expense:				
EPCO and affiliates	$ --	$ --	$ (274)	$ 170

For additional information regarding our related party transactions, see Note 13 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this Quarterly Report.

We have an extensive and ongoing relationship with EPCO and its affiliates, including TEPPCO. Our revenues from EPCO and affiliates are primarily associated with sales of NGL products. Our expenses with EPCO and affiliates are primarily due to (i) reimbursements we pay EPCO in connection with an administrative services agreement (the “ASA”) and (ii) purchases of NGL products.

TEPPCO became a related party to us in February 2005 when its general partner was acquired by private company affiliates of EPCO. Our relationship with TEPPCO was further strengthened by the acquisition of TEPPCO’s general partner by Enterprise GP Holdings in May 2007. Enterprise GP Holdings also owns our general partner. TEPPCO is also a joint venture partner with us in Jonah Gas Gathering Company and the Texas Offshore Port System.

On February 5, 2007, our consolidated subsidiary, Duncan Energy Partners, completed an initial public offering of its units, which generated net proceeds of approximately $291.0 million. Duncan Energy Partners was formed in September 2006 to acquire, own and operate a diversified portfolio of midstream energy assets and to support the growth objectives of EPO.

Enterprise GP Holdings acquired equity method investments in Energy Transfer Equity and its general partner in May 2007. As a result, Energy Transfer Equity and its consolidated subsidiaries became related parties to our consolidated businesses.

Many of our unconsolidated affiliates perform supporting or complementary roles to our consolidated business operations. The majority of our revenues from unconsolidated affiliates are earned from our sale of natural gas to Evangeline. The majority of our expenses with unconsolidated affiliates pertain to (i) our purchase of natural gas from Jonah and (ii) NGL transportation, storage and fractionation services we receive from K/D/S Promix, L.L.C.

Non-GAAP reconciliations

A reconciliation of our measurement of total non-GAAP gross operating margin to GAAP operating income and income before provision for income taxes and minority interest follows (dollars in thousands):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2008	**2007**	**2008**	**2007**
Total segment gross operating margin	$ 478,922	$ 363,721	$ 1,535,500	$ 1,061,568
Adjustments to reconcile total segment gross operating margin to operating income:				
Depreciation, amortization and accretion in operating costs and expenses	(138,417)	(133,869)	(408,601)	(374,522)
Operating lease expense paid by EPCO	(526)	(526)	(1,579)	(1,579)
Loss (gain) from asset sales and related transactions in operating costs and expenses	857	219	1,699	(5,445)
General and administrative costs	(21,720)	(18,715)	(66,901)	(66,706)
Operating income	319,116	210,830	1,060,118	613,316
Other expense, net	(101,479)	(83,369)	(287,672)	(213,327)
Income before provision for income taxes and minority interest	$ 217,637	$ 127,461	$ 772,446	$ 399,989

EPCO subleases to us certain equipment located at our Mont Belvieu facility and 100 railcars for $1 per year (the “retained leases”). These subleases are part of the ASA that we executed with EPCO in connection with our formation in 1998. EPCO holds this equipment pursuant to operating leases for which it has retained the corresponding cash lease payment obligation. We record the full value of such lease payments made by EPCO as a non-cash related party operating expense, with the offset to partners’ equity recorded as a general contribution to our partnership. Apart from the partnership interests we granted to EPCO at our formation, EPCO does not receive any additional ownership rights as a result of its contribution to us of the retained leases.

For the three and nine months ended September 30, 2008, we recorded $0.5 million and $1.6 million, respectively, of retained lease expense. We have exercised our election under the retained leases to purchase a cogeneration unit in December 2008 for $2.3 million. Should we decide to exercise the purchase option associated with the remaining agreement, we would pay the original lessor $3.1 million in June 2016.

Recent Accounting Pronouncements

On January 1, 2008, we adopted the provisions of Statement of Financial Accounting Standards (“SFAS”) 157, Fair Value Measurements, which apply to financial assets and liabilities. SFAS 157 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at a specified measurement date. See Note 4 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this Quarterly Report for information regarding fair value disclosures pertaining to our financial assets and liabilities.

For information regarding accounting developments during the first nine months of 2008 that will affect our future financial statements, see Note 2 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this Quarterly Report.

Weather-related Risks

We participate as a named insured in EPCO’s insurance program, which provides us with property damage, business interruption and other coverages, the scope and amounts of which are customary and sufficient for the nature and extent of our operations. While we believe EPCO maintains adequate insurance coverage on our behalf, insurance will not cover every type of interruption that might occur. If we were to incur a significant liability for which we were not fully insured, it could have a material impact on our consolidated financial position, results of operations and cash flows. In addition, the proceeds of any such insurance may not be paid in a timely manner and may be insufficient to reimburse us for our repair costs or lost income. Any event that interrupts the revenues generated by our consolidated operations, or which causes us to make significant expenditures not covered by insurance, could reduce our ability to pay distributions to our partners and, accordingly, adversely affect the market price of our common units.

For windstorm events such as hurricanes and tropical storms, EPCO's deductible for onshore physical damage is $10.0 million per storm. For offshore assets, the windstorm deductible is $10.0 million per storm plus a one-time $15.0 million aggregate deductible per policy period. For non-windstorm events, EPCO's deductible for onshore and offshore physical damage is $5.0 million per occurrence. In meeting the deductible amounts, property damage costs are aggregated for EPCO and its affiliates, including us. Accordingly, our exposure with respect to the deductibles may be equal to or less than the stated amounts depending on whether other EPCO or affiliate assets are also affected by an event.

To qualify for business interruption coverage in connection with a windstorm event, covered assets must be out-of-service in excess of 60 days for onshore assets and 75 days for offshore assets. To qualify for business interruption coverage in connection with a non-windstorm event, covered onshore and offshore assets must be out-of-service in excess of 60 days.

Hurricanes Gustav and Ike

In the third quarter of 2008, our onshore and offshore facilities located along the Gulf Coast of Texas and Louisiana were adversely impacted by Hurricanes Gustav and Ike. The disruptions in natural gas, NGL and crude oil production caused by these storms resulted in decreased volumes for some of our pipeline systems, natural gas processing plants, NGL fractionators and offshore platforms, which, in turn, caused a decrease in gross operating margin from these operations. As a result of our allocated share of EPCO's insurance deductibles for windstorm coverage, we expensed a combined $46.0 million of repair costs for property damage in connection with these two storms. We expect to file property damage insurance claims to the extent repair costs exceed this amount. Due to the recent nature of these storms, we are still evaluating the total cost of repairs and the potential for business interruption claims on certain assets.

See Note 16 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this Quarterly Report for information regarding insurance matters in connection with Hurricanes Katrina and Rita.

Item 3. *Quantitative and Qualitative Disclosures about Market Risk.*

We are exposed to financial market risks, including changes in commodity prices, interest rates and foreign exchange rates. We may use financial instruments (e.g., futures, forwards, swaps, options and other financial instruments with similar characteristics) to mitigate the risks of certain identifiable and anticipated transactions. In general, the types of risks we attempt to hedge are those related to (i) the variability of future earnings, (ii) fair values of certain debt instruments and (iii) cash flows resulting from changes in applicable interest rates, commodity prices or exchange rates.

We recognize financial instruments as assets and liabilities on our Unaudited Condensed Consolidated Balance Sheets based on fair value. Fair value is generally defined as the amount at which a financial instrument could be exchanged in a current transaction between willing parties, not in a forced or liquidation sale. The estimated fair values of our financial instruments have been determined using available market information and appropriate valuation techniques. We must use considerable judgment, however, in interpreting market data and developing these estimates. Accordingly, our fair value estimates are not necessarily indicative of the amounts that we could realize upon disposition of these instruments.

The use of different market assumptions and/or estimation techniques could have a material effect on our estimates of fair value.

Changes in fair value of financial instrument contracts are recognized in earnings in the current period unless specific hedge accounting criteria are met. If the financial instrument meets the criteria of a fair value hedge, gains and losses incurred on the instrument will be recorded in earnings to offset corresponding losses and gains on the hedged item. If the financial instrument meets the criteria of a cash flow hedge, gains and losses incurred on the instrument are recorded in accumulated other comprehensive income. Gains and losses on cash flow hedges are reclassified from accumulated other comprehensive income to earnings when the forecasted transaction occurs or, as appropriate, over the economic life of the hedged item. A contract designated as a hedge of an anticipated transaction that is no longer likely to occur is immediately recognized in earnings.

To qualify for hedge accounting, the item to be hedged must expose us to risk and the related hedging instrument must reduce the exposure and meet the formal hedging requirements of SFAS 133, Accounting for Derivative Instruments and Hedging Activities (as amended and interpreted). We formally designate the financial instrument as a hedge and document and assess the effectiveness of the hedge at its inception and thereafter on a quarterly basis. Any hedge ineffectiveness is immediately recognized in earnings.

We routinely review our outstanding financial instruments in light of current market conditions. If market conditions warrant, some financial instruments may be closed out in advance of their contractual settlement dates thus realizing income or loss depending on the specific hedging criteria. When this occurs, we may enter into a new financial instrument to reestablish the hedge to which the closed instrument relates.

Interest Rate Risk Hedging Program

Our interest rate exposure results from variable and fixed interest rate borrowings under various debt agreements. We manage a portion of our interest rate exposures by utilizing interest rate swaps and similar arrangements, which allow us to convert a portion of fixed rate debt into variable rate debt or a portion of variable rate debt into fixed rate debt.

Fair Value Hedges – Interest Rate Swaps

As summarized in the following table, we had five interest rate swap agreements outstanding at September 30, 2008 that were accounted for as fair value hedges.

Hedged Fixed Rate Debt	Number of Swaps	Period Covered by Swap	Termination Date of Swap	Fixed to Variable Rate (1)	Notional Value
Senior Notes C, 6.375% fixed rate, due Feb. 2013	1	Jan. 2004 to Feb. 2013	Feb. 2013	6.375% to 5.02%	$100.0 million
Senior Notes G, 5.60% fixed rate, due Oct. 2014	4	4th Qtr. 2004 to Oct. 2014	Oct. 2014	5.60% to 3.63%	$400.0 million

(1) The variable rate indicated is the all-in variable rate for the current settlement period.

The aggregate fair value of the five interest rate swaps at September 30, 2008 was an asset of $13.2 million, with an offsetting increase in the fair value of the underlying debt. There were eleven interest rate swaps outstanding at December 31, 2007 having an aggregate fair value of $14.8 million (an asset). Interest expense for the three months ended September 30, 2008 and 2007 includes a $1.8 million benefit and a $2.3 million loss, respectively, from interest rate swap agreements. For the nine months ended September 30, 2008 and 2007, interest expense reflects a benefit of $3.2 million and a loss of $6.9 million, respectively, from interest rate swap agreements.

The following table summarizes the termination of our interest rate swaps during 2008 (dollars in millions):

	Notional Value	Cash Gains (1)
Interest rate swap portfolio, December 31, 2007	$ 1,050.0	$ --
First quarter of 2008 terminations	(200.0)	6.3
Second quarter of 2008 terminations	(250.0)	12.0
Third quarter of 2008 terminations (2)	(100.0)	--
Interest rate swap portfolio, September 30, 2008	$ 500.0	$ 18.3

(1) Cash gains resulting from the termination, or monetization, of interest rate swaps will be amortized to earnings as a reduction to interest expense over the remaining life of the underlying debt.
(2) In early October 2008, one counterparty filed for bankruptcy. At September 30, 2008, the fair value of this interest rate swap was $3.4 million and this amount has been fully reserved. Hedge accounting for this swap has been discontinued.

The following table shows the effect of hypothetical price movements on the estimated fair value of our interest rate swap portfolio and the related change in fair value ("FV") of the underlying debt at the dates indicated (dollars in millions). Income is not affected by changes in the fair value of these swaps; however, these swaps effectively convert the hedged portion of fixed-rate debt to variable-rate debt. As a result, interest expense (and related cash outlays for debt service) will increase or decrease with the change in the periodic "reset" rate associated with the respective swap. Typically, the reset rate is an agreed upon index rate published for the first day of the six-month interest calculation period.

		Portfolio Fair Value at	
Scenario	Resulting Classification	September 30, 2008	October 21, 2008
FV assuming no change in underlying interest rates	*Asset*	$ 13.2	$ 20.1
FV assuming 10% increase in underlying interest rates	*Asset*	3.0	11.2
FV assuming 10% decrease in underlying interest rates	*Asset*	23.3	28.9

Cash Flow Hedges – Interest Rate Swaps

Duncan Energy Partners had three floating-to-fixed interest rate swap agreements outstanding at September, 2008 that were accounted for as cash flow hedges.

Hedged Variable Rate Debt	Number of Swaps	Period Covered by Swap	Termination Date of Swap	Variable to Fixed Rate (1)	Notional Value
Duncan Energy Partners' Revolver, due Feb. 2011	3	Sep. 2007 to Sep. 2010	Sep. 2010	3.77% to 4.62%	$175.0 million

(1) Amounts receivable from or payable to the swap counterparties are settled every three months (the "settlement period").

We recognized losses of $0.8 million and $1.6 million from these swap agreements during the three and nine months ended September 30, 2008, respectively. The aggregate fair values of these interest rate swaps at September 30, 2008 and December 31, 2007 were liabilities of $4.3 million and $3.8 million, respectively. As cash flow hedges, any increase or decrease in fair value of the financial instrument (to the extent effective) would be recorded as other comprehensive income and amortized into earnings based on the settlement period being hedged. Over the next twelve months, we expect to reclassify $1.4 million of losses to earnings as an increase in interest expense.

The following table shows the effect of hypothetical price movements on the estimated fair value of Duncan Energy Partners' interest rate swap portfolio (dollars in millions).

		Portfolio Fair Value at	
Scenario	Resulting Classification	September 30, 2008	October 21, 2008
FV assuming no change in underlying interest rates	*Liability*	$ (4.3)	$ (6.3)
FV assuming 10% increase in underlying interest rates	*Liability*	(3.3)	(5.5)
FV assuming 10% decrease in underlying interest rates	*Liability*	(5.3)	(7.1)

Cash Flow Hedges – Treasury Locks

We occasionally use treasury lock financial instruments to hedge the underlying U.S. treasury rates related to our anticipated issuances of debt. Cash gains or losses on the termination, or monetization, of such instruments are amortized to earnings using the effective interest method over the estimated term of the underlying fixed-rate debt. Each of our treasury lock transactions were designated as a cash flow hedge. The following table summarizes changes in our treasury lock portfolio since December 31, 2007 (dollars in millions).

	Notional Value	Cash Losses (1)
Treasury lock portfolio, December 31, 2007	$ 600.0	$ --
First quarter of 2008 terminations	(350.0)	27.7
Second quarter of 2008 terminations	(250.0)	12.7
Treasury lock portfolio, September 30, 2008	$ --	$ 40.4

(1) Cash losses are included in net interest rate financial instrument losses in the Unaudited Condensed Statements of Consolidated Comprehensive Income.

We expect to reclassify $1.8 million of cumulative net gains from the monetization of treasury lock financial instruments to earnings (as a decrease in interest expense) over the next twelve months. This includes financial instruments that were settled in years prior to 2008.

Commodity Risk Hedging Program

The prices of natural gas, NGLs and certain petrochemical products are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control. In order to manage the price risks associated with such products, we may enter into commodity financial instruments.

The primary purpose of our commodity risk management activities is to reduce our exposure to price risks associated with (i) natural gas purchases, (ii) the value of NGL production and inventories, (iii) related firm commitments, (iv) fluctuations in transportation revenues where the underlying fees are based on natural gas index prices and (v) certain anticipated transactions involving either natural gas, NGLs or certain petrochemical products. From time to time, we inject natural gas into storage and may utilize hedging instruments to lock in the value of our inventory positions. The commodity financial instruments we utilize may be settled in cash or with another financial instrument.

We assess the risk of our commodity financial instrument portfolio using a sensitivity analysis model. The sensitivity analysis applied to the portfolio measures the potential income or loss (i.e., the change in fair value of the portfolio) based upon a hypothetical 10% movement in the underlying quoted market prices of the commodity financial instruments outstanding at the date indicated within the following table.

We have segregated our commodity financial instruments portfolio between those financial instruments utilized in connection with our natural gas marketing activities and those used in connection with our NGL and petrochemical operations.

Natural gas marketing activities. At September 30, 2008 and December 31, 2007, the aggregate fair values of those financial instruments utilized in connection with our natural gas marketing activities was an asset of $0.8 million and a liability of $0.3 million, respectively. Our natural gas marketing business and its related use of financial instruments has increased since December 31, 2007. We currently utilize mark-to-market accounting for substantially all of the financial instruments utilized in connection with our natural gas marketing activities. The following table presents gains and losses recognized in earnings from this portion of the commodity financial instruments portfolio for the periods indicated (dollars in millions):

Three months ended September 30, 2008	Gains	$	13.2
Three months ended September 30, 2007	Losses	$	(0.6)
Nine months ended September 30, 2008	Gains	$	7.8
Nine months ended September 30, 2007	Losses	$	(0.1)

The following table shows the effect of hypothetical price movements on the estimated fair value of this component of the overall portfolio at the dates presented (dollars in millions):

		Portfolio Fair Value at	
Scenario	**Resulting Classification**	**September 30, 2008**	**October 21, 2008**
FV assuming no change in underlying commodity prices	*Asset (Liability)*	$ 0.8	$ (0.5)
FV assuming 10% increase in underlying commodity prices	*(Liability)*	(3.8)	(7.8)
FV assuming 10% decrease in underlying commodity prices	*Asset*	6.0	6.9

The change in fair value of the instruments between September 30, 2008 and October 21, 2008 is primarily due to a decrease in natural gas prices.

NGL and petrochemical operations. At September 30, 2008 and December 31, 2007, the aggregate fair values of financial instruments utilized in connection with our NGL and petrochemical operations were liabilities of $116.6 million and $19.0 million, respectively. The change in fair value between December 31, 2007 and September 30, 2008 is primarily due to a decrease in the price of natural gas and an increase in volumes hedged. Almost all of the financial instruments within this portion of the commodity financial instruments portfolio are accounted for as cash flow hedges, with a small number accounted for using mark-to-market accounting.

EPO has employed a program to economically hedge a portion of earnings from its natural gas processing business (a component of its NGL Pipelines & Services business segment). This program consists of (i) the forward sale of a portion of EPO's expected equity NGL production volumes at fixed prices through 2009 and (ii) the purchase (using commodity financial instruments) of the amount of natural gas expected to be consumed as plant thermal reduction ("PTR") in the production of such equity NGL volumes. The objective of this strategy is to hedge a level of gross margins (i.e., NGL sales revenues less actual costs for PTR and the gain or loss on the PTR hedge) associated with the forward sales contracts by fixing the cost of natural gas used for PTR, through the use of commodity financial instruments. At September 30, 2008, this hedging program had hedged future gross margins before plant operating expenses of $588.8 million for 28.8 million barrels of forecasted NGL forward sales transactions extending through 2009.

NGL forward sales contracts are not accounted for as financial instruments under SFAS 133; therefore, changes in the aggregate economic value of these sales contracts are not reflected in earnings and comprehensive income until the volumes are delivered to customers. On the other hand, the commodity financial instruments used to purchase the related quantities of PTR (i.e., "PTR hedges") are accounted for as cash flow hedges; therefore, changes in the aggregate fair value of the PTR hedges are presented in other comprehensive income.

Prior to actual settlement, if the market price of natural gas is less than the price stipulated in a PTR hedge, we recognize an unrealized loss in other comprehensive income for the excess of the natural gas price stated in the PTR hedge over the market price. To the extent that we realize such financial losses upon settlement of the instrument, the losses are added to the actual cost we have to pay for PTR (which would then be based on the lower market price). The end result of this relationship – financial gain/loss on the PTR hedges plus the market price of actual natural gas purchases at the time of consumption – is that our total cost of natural gas used for PTR approximates the amount we originally hedged under this program The converse is true if the price of natural gas decreases. During the third quarter of 2008, the price of natural gas decreased approximately 45% from June 30, 2008. As a result, we recognized unrealized losses in other comprehensive income with respect to the PTR hedges of $258.4 million during the third quarter of 2008. For the nine months ended September 30, 2008, we recognized unrealized losses in other comprehensive income of $126.0 million with respect to the PTR hedging program. Once the forecasted NGL forward sales transactions occur, any realized gains and losses on the cash flow hedges would be reclassified into earnings at that time.

At November 1, 2008, this program had hedged future gross margins before plant operating expenses of $550.0 million for 27.3 million barrels of forecasted NGL forward sales transactions extending through 2009. The aggregate fair value of the PTR cash flow hedges at this date was a liability of $155.3 million.

The following table presents gains and losses recognized in earnings from this portion of the commodity financial instruments portfolio for the periods indicated (dollars in millions):

Three months ended September 30, 2008 (1)	Losses	$	(7.2)
Three months ended September 30, 2007	Losses	$	(10.1)
Nine months ended September 30, 2008 (2)	Gains	$	1.7
Nine months ended September 30, 2007	Losses	$	(11.9)

(1) Includes ineffectiveness of $5.6 million (an expense).
(2) Includes ineffectiveness of $2.8 million (an expense).

The following table shows the effect of hypothetical price movements on the estimated fair value of this component of the overall portfolio at the dates presented (dollars in millions):

		Portfolio Fair Value at	
Scenario	**Resulting Classification**	**September 30, 2008**	**October 21, 2008**
FV assuming no change in underlying commodity prices	*(Liability)*	$ (116.6)	$ (107.4)
FV assuming 10% increase in underlying commodity prices	*(Liability)*	(97.3)	(86.0)
FV assuming 10% decrease in underlying commodity prices	*(Liability)*	(136.0)	(128.8)

The change in fair value of the NGL and petrochemical portfolio between September 30, 2008 and October 21, 2008 is primarily due to a decrease in natural gas prices. A significant number of the financial instruments in this portfolio hedge the purchase of physical natural gas. If natural gas prices fall below the price stipulated in such financial instruments, we recognize a liability for the difference; however, if prices partially or fully recover, this liability would be reduced or eliminated, as appropriate.

Foreign Currency Hedging Program

We are exposed to foreign currency exchange rate risk primarily through our Canadian NGL marketing subsidiary. As a result, we could be adversely affected by fluctuations in the foreign currency exchange rate between the U.S. dollar and the Canadian dollar. We attempt to hedge this risk using foreign exchange purchase contracts to fix the exchange rate. Mark-to-market accounting is utilized for these contracts, which typically have a duration of one month. For the nine months ended September 30, 2008, we recorded minimal gains from these financial instruments. No such amounts were recorded in the third quarter of 2008.

Fair Value Information

On January 1, 2008, we adopted the provisions of SFAS 157 that apply to financial assets and liabilities. SFAS 157 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at a specified measurement date. See Note 4 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this Quarterly Report for information regarding fair value disclosures pertaining to our financial assets and liabilities.

Accumulated Other Comprehensive Income (Loss)

Accumulated other comprehensive income (loss) primarily includes the effective portion of the gain or loss on financial instruments designated and qualified as a cash flow hedge, foreign currency adjustments and Dixie's minimum pension liability adjustments. Amounts accumulated in other comprehensive income (loss) from cash flow hedges are reclassified into earnings in the same period(s) in which the hedged forecasted transactions (such as a forecasted forward sale of NGLs) affect earnings. If it becomes probable that the forecasted transaction will not occur, the net gain or loss in accumulated other comprehensive income (loss) must be immediately reclassified.

The following table presents the components of accumulated other comprehensive income (loss) at the dates indicated:

	September 30, 2008	December 31, 2007
Commodity financial instruments – cash flow hedges (1)	$ (129,913)	$ (21,619)
Interest rate financial instruments – cash flow hedges	9,714	34,980
Foreign currency cash flow hedges	--	1,308
Foreign currency translation adjustment (2)	1,652	1,200
Pension and postretirement benefit plans (3)	324	588
Total accumulated other comprehensive income (loss)	$ (118,223)	$ 16,457

(1) The negative change in fair value of commodity financial instruments between December 31, 2007 and September 30, 2008 is primarily due to a significant decrease in natural gas prices during the third quarter of 2008.
(2) Relates to transactions of our Canadian NGL marketing subsidiary.
(3) See Note 2 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this Quarterly Report for additional information regarding Dixie's pension and postretirement benefit plans.

Item 4. *Controls and Procedures.*

Our management, with the participation of the Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") of Enterprise Products GP, has evaluated the effectiveness of our disclosure controls and procedures, as of September 30, 2008. Based on their evaluation, the CEO and CFO of Enterprise Products GP have concluded that our disclosure controls and procedures (as defined in Rule 13a-15(e)) are effective at a reasonable assurance level.

There have been no changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) during our last fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Disclosure controls and procedures are designed to provide reasonable assurance that information required to be disclosed by us in reports that are filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time specified in the Commission's rules and forms, including to provide reasonable assurance that such information is accumulated and communicated to our management, including the CEO and CFO of our general partner, as appropriate, to allow timely decisions regarding required disclosures. Our management does not expect that our disclosure controls and procedures will prevent all errors and all fraud. The design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Based on the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the Partnership have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple errors or mistakes. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the controls. The design of any system of controls is also based in part upon certain assumptions about the likelihood of future events. Therefore, a control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

The certifications of our general partner's CEO and CFO required under Sections 302 and 906 of the Sarbanes-Oxley Act of 2002 have been included as exhibits to this Quarterly Report on Form 10-Q.

PART II. OTHER INFORMATION.

Item 1. *Legal Proceedings*.

See Part I, Item 1, Financial Statements, Note 15, "Commitments and Contingencies – Litigation," of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this Quarterly Report, which is incorporated herein by reference.

Item 1A. *Risk Factors*.

Apart from that discussed below, there have been no significant changes in our risk factors since December 31, 2007. For a detailed discussion of our risk factors, please read Part I, Item 1A "Risk Factors," in our Annual Report on Form 10-K for the year ended December 31, 2007.

Our recently announced TOPS joint venture, like other projects for new facilities, is subject to various business, operational and regulatory risks and may not be successful.

The TOPS joint venture is expected to represent an important component of our Offshore Pipelines & Services segment, requiring an estimated $617.4 million in capital contributions from us through 2011 (excluding capitalized interest). We, as well as each of our other two joint venture partners, will own a one-third interest in TOPS, and we will act as operator and construction manager for TOPS. We may be unable to make required capital contributions due to an inability to access capital markets or otherwise, in which event our interest could be diluted, and we could suffer other adverse consequences. Please read the risk factor in Item 1A of our most recent Form 10-K "*We may not be able to fully execute our growth strategy if we encounter illiquid capital markets or increased competition for investment opportunities*."

Delays in completing construction or commencement of operations of TOPS due to any cause would delay our future operating cash flows, which could have a material adverse effect on the success of the TOPS project and on our business, results of operations, financial condition and prospects. As with our other construction projects for new facilities, it may take a period of time before we realize any expected cash flows from such assets. Please read the risk factor in Item 1A of our most recent Form 10-K "*Our operating cash flows from our capital projects may not be immediate*."

Commencement of the TOPS joint venture operations, like other new facilities, is also subject to obtaining necessary regulatory and third-party approvals. The offshore terminal will require approval by the U.S. Coast Guard and issuance of a Deepwater Port License, while the onshore pipeline and storage facilities will be subject to review by the U.S. Environmental Protection Agency, Army Corps of Engineers and Department of Transportation. Obtaining such approvals is a time consuming process. For example, we estimate that the Deepwater Port License could take as long as two years, assuming there are no delaying factors. These and other regulatory, environmental, political and legal risks are beyond our control and may also require the expenditure of unexpected amounts of capital. Please read the risk factor in Item 1A of our most recent Form 10-K "*Our construction of new assets is subject to regulatory, environmental, political, legal and economic risks, which may result in delays, increased costs or decreased cash flows*."

The TOPS joint venture is also subject to significant logistical, technological and staffing requirements, as well as force majeure events such as hurricanes along the Gulf Coast, that could result in delays or significant increases in the project's current estimated costs. Please read the risk factor in Item 1A of our most recent Form 10-K "*Our actual construction, development and acquisition costs could exceed forecasted amounts*."

The global financial crisis may have impacts on our business and financial condition that we currently cannot predict.

The continued credit crisis and related turmoil in the global financial system has had, and may continue to have, an impact on our business and our financial condition. We may face significant challenges if conditions in the financial markets do not improve. Our ability to access the capital markets may be severely restricted at a time when we would like, or need, to do so, which could have an adverse impact on our ability to meet our capital commitments and flexibility to react to changing economic and business conditions. The credit crisis could have a negative impact on our lenders or our customers, causing them to fail to meet their obligations to us. Additionally, demand for our services and products depends on activity and expenditure levels in the energy industry, which are directly and negatively impacted by depressed oil and gas prices. Any of these factors could lead to reduced usage of our pipelines and energy logistics services, which could have a material negative impact on our revenues and prospects.

Item 2. *Unregistered Sales of Equity Securities and Use of Proceeds.*

As of September 30, 2008, we and our affiliates are authorized to repurchase up to 618,400 common units under the December 1998 common unit repurchase program. We did not repurchase any of our common units in connection with this announced program during the three or nine months ended September 30, 2008.

The following table summarizes our repurchase activity during 2008 in connection with other arrangements:

Period	Total Number of Units Purchased	Average Price Paid per Unit	Total Number of of Units Purchased as Part of Publicly Announced Plans	Maximum Number of Units That May Yet Be Purchased Under the Plans
May 2008	21,413 (1)	$30.37	-0-	-0-
August 2008	4,940 (2)	$29.19	-0-	-0-
September 2008	4,565 (3)	$25.77	-0-	-0-

(1) Of the 67,500 restricted unit awards that vested in May 2008 and converted to common units, 21,413 of these units were sold back to the partnership by employees to cover related withholding tax requirements.
(2) Of the 28,650 restricted unit awards that vested in August 2008 and converted to common units, 4,940 of these units were sold back to the partnership by employees to cover related withholding tax requirements.
(3) Of the 16,500 restricted unit awards that vested in September 2008 and converted to common units, 4,565 of these units were sold back to the partnership by employees to cover related withholding tax requirements.

Item 3. *Defaults upon Senior Securities.*

None.

Item 4. *Submission of Matters to a Vote of Security Holders.*

On January 29, 2008, we held a special meeting where our unitholders where asked to approve the terms of the Enterprise Products 2008 Long-Term Incentive Plan (the “2008 LTIP”). See Item 4 of our Annual Report on Form 10-K for information regarding this matter and related vote totals.

Item 5. ***Other Information.***

Amendments to Partnership Agreement

On November 6, 2008, our general partner amended our agreement of limited partnership to amend Section 7.7(i) to clarify and to provide that any amendment of Section 7.7 shall not impair an indemnitee's right to receive expense advancement, in addition to indemnification, from us as otherwise provided for under the partnership agreement. In addition, the member of our general partner amended its limited liability company agreement to make a similar change.

A copy of the amendments to our partnership agreement and our general partner's limited liability company agreement are attached hereto as Exhibit 3.5 and Exhibit 3.7, respectively, and are incorporated by reference herein.

Item 6. ***Exhibits.***

Exhibit Number	Exhibit*
2.1	Merger Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products Management LLC, GulfTerra Energy Partners, L.P. and GulfTerra Energy Company, L.L.C. (incorporated by reference to Exhibit 2.1 to Form 8-K filed December 15, 2003).
2.2	Amendment No. 1 to Merger Agreement, dated as of August 31, 2004, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products Management LLC, GulfTerra Energy Partners, L.P. and GulfTerra Energy Company, L.L.C. (incorporated by reference to Exhibit 2.1 to Form 8-K filed September 7, 2004).
2.3	Parent Company Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products GTM, LLC, El Paso Corporation, Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso EPN Investments, L.L.C. and GulfTerra GP Holding Company (incorporated by reference to Exhibit 2.2 to Form 8-K filed December 15, 2003).
2.4	Amendment No. 1 to Parent Company Agreement, dated as of April 19, 2004, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products GTM, LLC, El Paso Corporation, Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso EPN Investments, L.L.C. and GulfTerra GP Holding Company (incorporated by reference to Exhibit 2.1 to the Form 8-K filed April 21, 2004).
2.5	Purchase and Sale Agreement (Gas Plants), dated as of December 15, 2003, by and between El Paso Corporation, El Paso Field Services Management, Inc., El Paso Transmission, L.L.C., El Paso Field Services Holding Company and Enterprise Products Operating L.P. (incorporated by reference to Exhibit 2.4 to Form 8-K filed December 15, 2003).
3.1	Certificate of Limited Partnership of Enterprise Products Partners L.P. (incorporated by reference to Exhibit 3.6 to Form 10-Q filed November 8, 2007).
3.2	Fifth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P., dated effective as of August 8, 2005 (incorporated by reference to Exhibit 3.1 to Form 8-K filed August 10, 2005).
3.3	First Amendment to Fifth Amended and Restated Partnership Agreement of Enterprise Products Partners L.P. dated as of December 27, 2007 (incorporated by reference to Exhibit 3.1 to Form 8-K/A filed January 3, 2008).
3.4	Second Amendment to Fifth Amended and Restated Partnership Agreement of Enterprise Products Partners L.P. dated as of April 14, 2008 (incorporated by reference to Exhibit 10.1 to Form 8-K filed April 16, 2008).
3.5#	Third Amendment to Fifth Amended and Restated Partnership Agreement of Enterprise Products Partners L.P. dated as of November 6, 2008.

3.6	Fifth Amended and Restated Limited Liability Company Agreement of Enterprise Products GP, LLC, dated as of November 7, 2007 (incorporated by reference to Exhibit 3.2 to Form 10-Q filed November 8, 2007).
3.7#	First Amendment to Fifth Amended and Restated Limited Liability Company Agreement of Enterprise Products GP, LLC, dated as of November 6, 2008.
3.8	Limited Liability Company Agreement of Enterprise Products Operating LLC dated as of June 30, 2007 (incorporated by reference to Exhibit 3.3 to Form 10-Q filed on August 8, 2007).
3.9	Certificate of Incorporation of Enterprise Products OLPGP, Inc., dated December 3, 2003 (incorporated by reference to Exhibit 3.5 to Form S-4 Registration Statement, Reg. No. 333-121665, filed December 27, 2004).
3.10	Bylaws of Enterprise Products OLPGP, Inc., dated December 8, 2003 (incorporated by reference to Exhibit 3.6 to Form S-4 Registration Statement, Reg. No. 333-121665, filed December 27, 2004).
3.11	Certificate of Limited Partnership of Duncan Energy Partners L.P. (incorporated by reference to Exhibit 3.1 to Duncan Energy Partners L.P. Form S-1 Registration Statement, Reg. No. 333-138371, filed November 2, 2006).
3.12	Amended and Restated Agreement of Limited Partnership of Duncan Energy Partners L.P., dated February 5, 2007 (incorporated by reference to Exhibit 3.1 to Duncan Energy Partners L.P.'s Form 8-K/A filed February 5, 2007).
3.13	First Amendment to Amended and Restated Partnership Agreement of Duncan Energy Partners L.P. dated as of December 27, 2007 (incorporated by reference to Exhibit 3.1 to Duncan Energy Partners L.P.'s Form 8-K/A filed on January 3, 2008).
4.1	Form of Common Unit certificate (incorporated by reference to Exhibit 4.1 to Registration Statement on Form S-1/A; File No. 333-52537, filed July 21, 1998).
4.2	Indenture dated as of March 15, 2000, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and First Union National Bank, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed March 10, 2000).
4.3	First Supplemental Indenture dated as of January 22, 2003, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Registration Statement on Form S-4, Reg. No. 333-102776, filed January 28, 2003).
4.4	Second Supplemental Indenture dated as of February 14, 2003, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 10-K filed March 31, 2003).
4.5	Third Supplemental Indenture dated as of June 30, 2007, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Guarantor, and U.S. Bank National Association, as successor Trustee (incorporated by reference to Exhibit 4.55 to Form 10-Q filed on August 8, 2007) .
4.6	Amended and Restated Revolving Credit Agreement dated as of November 19, 2007 among Enterprise Products Operating LLC, the financial institutions party thereto as lenders, Wachovia Bank, National Association, as Administrative Agent, Issuing Bank and Swingline Lender, Citibank, N.A. and JPMorgan Chase Bank, as Co-Syndication Agents, and SunTrust Bank, Mizuho Corporate Bank, Ltd. and The Bank of Nova Scotia, as Co-Documentation Agents (incorporated by reference to Exhibit 10.1 to Form 8-K filed on November 20, 2007).
4.7	Amended and Restated Guaranty Agreement dated as of November 19, 2007 executed by Enterprise Products Partners L.P. in favor of Wachovia Bank, National Association, as Administrative Agent (incorporated by reference to Exhibit 10.2 to Form 8-K filed on November 20, 2007).
4.8	Indenture dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed on October 6, 2004).

4.9	First Supplemental Indenture dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed on October 6, 2004).
4.10	Second Supplemental Indenture dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed on October 6, 2004).
4.11	Third Supplemental Indenture dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.4 to Form 8-K filed on October 6, 2004).
4.12	Fourth Supplemental Indenture dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.5 to Form 8-K filed on October 6, 2004).
4.13	Fifth Supplemental Indenture dated as of March 2, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed on March 3, 2005).
4.14	Sixth Supplemental Indenture dated as of March 2, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed on March 3, 2005).
4.15	Seventh Supplemental Indenture dated as of June 1, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.46 to Form 10-Q filed November 4, 2005).
4.16	Eighth Supplemental Indenture dated as of July 18, 2006 to Indenture dated October 4, 2004 among Enterprise Products Operating L.P., as issuer, Enterprise Products Partners L.P., as parent guarantor, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to exhibit 4.2 to Form 8-K filed July 19, 2006).
4.17	Ninth Supplemental Indenture, dated as of May 24, 2007, by and among Enterprise Products Operating L.P., as issuer, Enterprise Products Partners L.P., as parent guarantor, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K filed by Enterprise Products Partners L.P. on May 24, 2007).
4.18	Tenth Supplemental Indenture, dated as of June 30, 2007, by and among Enterprise Products Operating LLC, as issuer, Enterprise Products Partners L.P., as parent guarantor, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.54 to Form 10-Q filed August 8, 2007).
4.19	Eleventh Supplemental Indenture, dated as of September 4, 2007, by and among Enterprise Products Operating LLC, as issuer, Enterprise Products Partners L.P., as parent guarantor, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed on September 5, 2007).
4.20	Twelfth Supplemental Indenture, dated as of April 3, 2008, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed April 3, 2008).
4.21	Thirteenth Supplemental Indenture, dated as of April 3, 2008, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.4 to Form 8-K filed April 3, 2008).
4.22	Global Note representing $350 million principal amount of 6.375% Series B Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Registration Statement on Form S-4, Reg. No. 333-102776, filed January 28, 2003).

4.23	Global Note representing $500 million principal amount of 6.875% Series B Senior Notes due 2033 with attached Guarantee (incorporated by reference to Exhibit 4.8 to Form 10-K filed March 31, 2003).
4.24	Global Notes representing $450 million principal amount of 7.50% Senior Notes due 2011 (incorporated by reference to Exhibit 4.1 to Form 8-K filed January 25, 2001).
4.25	Global Note representing $500 million principal amount of 4.000% Series B Senior Notes due 2007 with attached Guarantee (incorporated by reference to Exhibit 4.14 to Form S-3 Registration Statement Reg. No. 333-123150 filed on March 4, 2005).
4.26	Global Note representing $500 million principal amount of 5.600% Series B Senior Notes due 2014 with attached Guarantee (incorporated by reference to Exhibit 4.17 to Form S-3 Registration Statement Reg. No. 333-123150 filed on March 4, 2005).
4.27	Global Note representing $150 million principal amount of 5.600% Series B Senior Notes due 2014 with attached Guarantee (incorporated by reference to Exhibit 4.18 to Form S-3 Registration Statement Reg. No. 333-123150 filed on March 4, 2005).
4.28	Global Note representing $350 million principal amount of 6.650% Series B Senior Notes due 2034 with attached Guarantee (incorporated by reference to Exhibit 4.19 to Form S-3 Registration Statement Reg. No. 333-123150 filed on March 4, 2005).
4.29	Global Note representing $500 million principal amount of 4.625% Series B Senior Notes due 2009 with attached Guarantee (incorporated by reference to Exhibit 4.27 to Form 10-K for the year ended December 31, 2004 filed on March 15, 2005).
4.30	Global Note representing $250,000,000 principal amount of 5.00% Series B Senior Notes due 2015 with attached Guarantee (incorporated by reference to Exhibit 4.31 to Form 10-Q filed on November 4, 2005).
4.31	Global Note representing $250,000,000 principal amount of 5.75% Series B Senior Notes due 2035 with attached Guarantee (incorporated by reference to Exhibit 4.32 to Form 10-Q filed on November 4, 2005).
4.32	Global Note representing $500,000,000 principal amount of 4.95% Senior Notes due 2010 with attached Guarantee (incorporated by reference to Exhibit 4.47 to Form 10-Q filed November 4, 2005).
4.33	Form of Junior Note, including Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed July 19, 2006).
4.34	Global Note representing $800,000,000 principal amount of 6.30% Senior Notes due 2017 with attached Guarantee (incorporated by reference to Exhibit 4.38 to Form 10-Q filed November 8, 2007).
4.35	Form of Global Note representing $400,000,000 principal amount of 5.65% Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed April 3, 2008).
4.36	Form of Global Note representing $700,000,000 principal amount of 6.55% Senior Notes due 2019 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed April 3, 2008).
4.37	Amended and Restated Credit Agreement dated as of June 29, 2005, among Cameron Highway Oil Pipeline Company, the Lenders party thereto, and SunTrust Bank, as Administrative Agent and Collateral Agent (incorporated by reference to Exhibit 4.1 to Form 8-K filed on July 1, 2005).
4.38	Replacement Capital Covenant, dated May 24, 2007, executed by Enterprise Products Operating L.P. and Enterprise Products Partners L.P. in favor of the covered debtholders described therein (incorporated by reference to Exhibit 99.1 to the Current Report on Form 8-K filed by Enterprise Products Partners L.P. on May 24, 2007).
4.39	First Amendment to Replacement Capital Covenant dated August 25, 2006, executed by Enterprise Products Operating L.P. in favor of the covered debtholders described therein (incorporated by reference to Exhibit 99.2 to Form 8-K filed August 25, 2006).
4.40	Purchase Agreement, dated as of July 12, 2006 between Cerrito Gathering Company, Ltd., Cerrito Gas Marketing, Ltd., Encinal Gathering, Ltd., as Sellers, Lewis Energy Group, L.P. as Guarantor, and Enterprise Products Partners L.P., as buyer (incorporated by reference to Exhibit 4.6 to Form 10-Q filed August 8, 2006).

10.1***	Second Amendment to Agreement of Limited Partnership of EPE Unit L.P. dated July 1, 2008 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Enterprise GP Holdings L.P. on July 7, 2008).
10.2***	Second Amendment to Agreement of Limited Partnership of EPE Unit II, L.P. dated July 1, 2008 (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed by Enterprise GP Holdings L.P. on July 7, 2008).
10.3***	Second Amendment to Agreement of Limited Partnership of EPE Unit III, L.P. dated July 1, 2008 (incorporated by reference to Exhibit 10.3 to the Current Report Form 8-K filed by Enterprise GP Holdings L.P. on July 7, 2008).
10.4*	Second Amended and Restated Limited Liability Company Agreement of Mont Belvieu Caverns, LLC, dated November 6, 2008 (incorporated by reference to Exhibit 10.4 to Form 10-Q filed by Duncan Energy Partners L.P. on November 10, 2008).
31.1#	Sarbanes-Oxley Section 302 certification of Michael A. Creel for Enterprise Products Partners L.P. for the September 30, 2008 quarterly report on Form 10-Q.
31.2#	Sarbanes-Oxley Section 302 certification of W. Randall Fowler for Enterprise Products Partners L.P. for the September 30, 2008 quarterly report on Form 10-Q.
32.1#	Section 1350 certification of Michael A. Creel for the September 30, 2008 quarterly report on Form 10-Q.
32.2#	Section 1350 certification of W. Randall Fowler for the September 30, 2008 quarterly report on Form 10-Q.

* With respect to any exhibits incorporated by reference to any Exchange Act filings, the Commission file number for Enterprise Products Partners L.P., Duncan Energy Partners L.P. and Enterprise GP Holdings L.P. are 1-14323, 1-33266 and 1-32610, respectively.

*** Identifies management contract and compensatory plan arrangements.

\# Filed with this report.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this Quarterly Report on Form 10-Q to be signed on its behalf by the undersigned thereunto duly authorized, in the City of Houston, State of Texas on November 10, 2008.

ENTERPRISE PRODUCTS PARTNERS L.P.
(A Delaware Limited Partnership)

By: Enterprise Products GP, LLC, as General Partner

By: ___/s/ Michael J. Knesek____________________
Name: Michael J. Knesek
Title: Senior Vice President, Controller
and Principal Accounting Officer
of the General Partner

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Section 2: EX-3.5 (EXHIBIT 3.5)

Exhibit 3.5

AMENDMENT NO. 3 TO THE FIFTH AMENDED AND RESTATED AGREEMENT OF LIMITED PARTNERSHIP OF ENTERPRISE PRODUCTS PARTNERS L.P.

This Amendment No. 3 (this "*Amendment No.3*") to the Fifth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P. dated effective as of August 8, 2005 (the "*Partnership Agreement*") is hereby adopted by Enterprise Products GP, LLC, a Delaware limited liability company (the "*General Partner*"), as general partner of the Partnership. Capitalized terms used but not defined herein are used as defined in the Partnership Agreement.

WHEREAS, acting pursuant to the power and authority granted to it under Section 13.1(d) of the Partnership Agreement, the General Partner has determined that the following amendment to the Partnership Agreement does not require the approval of any Limited Partner.

NOW THEREFORE, the General Partner does hereby amend the Partnership Agreement as follows:

Section 1. Sections 7.7(i) is hereby amended to read in full as follows:

(i) No amendment, modification or repeal of this Section 7.7 or any provision hereof shall in any manner terminate, reduce or impair the right of any past, present or future Indemnitee to receive indemnification (including expense advancement as provided by Section 7.7(b)) from the Partnership, nor the obligations of the Partnership to indemnify, or advance the expenses of, any such Indemnitee under and in accordance with the provisions of this Section 7.7 as in effect immediately prior to such amendment, modification or repeal with respect to claims arising from or relating to matters occurring, in whole or in part, prior to such amendment, modification or repeal, regardless of when such claims may arise or be asserted, and provided such Person became an Indemnitee hereunder prior to such amendment, modification or repeal.

Section 2. Except as hereby amended, the Partnership Agreement shall remain in full force and effect.

Section 3. This Amendment No. 3 shall be governed by, and interpreted in accordance with, the laws of the State of Delaware, all rights and remedies being governed by such laws without regard to principles of conflicts of laws.

IN WITNESS WHEREOF, this Amendment No. 3 has been executed as of November 6, 2008.

GENERAL PARTNER:

ENTERPRISE PRODUCTS GP, LLC

By: /s/ Michael A. Creel
Michael A. Creel
President and Chief Executive Officer

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Section 3: EX-3.7 (EXHIBIT 3.7)

Exhibit 3.7

FIRST AMENDMENT TO THE FIFTH AMENDED AND RESTATED LIMITED LIABILITY COMPANY AGREEMENT OF ENTERPRISE PRODUCTS GP, LLC

This First Amendment dated November 6, 2008 to the Fifth Amended and Restated Limited Liability Company Agreement (this "Amendment") of Enterprise Products GP, LLC ("EPD GP"), dated November 7, 2007, is executed by Enterprise GP Holdings L.P.

("EPE"). Capitalized terms used but not defined in this Amendment shall have the meaning set forth in the Limited Liability Company Agreement of EPD GP dated November 7, 2007 (the "LLC Agreement").

RECITALS

WHEREAS, EPE Holdings, LLC (the "Company") owns a 0.01% general partner interest in and is the sole general partner of EPE;

WHEREAS, EPE is the sole member of EPD GP;

WHEREAS, EPD GP owns a 2% general partnership interest in Enterprise Products Partners L.P., a Delaware limited partnership ("EPD LP"), and is the sole general partner of EPD LP;

WHEREAS, the Company, in its capacity as general partner of EPE, has determined that it is advisable to amend the LLC Agreement.

NOW, THEREFORE, in consideration of the agreements and obligations set forth herein and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged and intending to be legally bound, EPE hereby agrees as follows:

AGREEMENT

1. Section 6.06(i) of the LLC Agreement shall be deleted and restated in its entirety as follows:

(i) No amendment, modification or repeal of this Section 6.06 or any provision hereof shall in any manner terminate, reduce or impair either the right of any past, present or future Indemnitee to receive indemnification (including expense advancement as provided by Section 6.06(b)) from the Company or the obligation of the Company to indemnify, or advance the expenses of, any such Indemnitee under and in accordance with the provisions of this Section 6.06 as in effect immediately prior to such amendment, modification or repeal with respect to claims arising from or relating to matters occurring, in whole or in part, prior to such amendment, modification or repeal, regardless of when such claims may be asserted, and provided such Person became an Indemnitee hereunder prior to such amendment, modification or repeal.

2. Except as otherwise expressly provided by this Amendment, all of the terms, conditions and provisions of the LLC Agreement shall remain the same. This Amendment shall be governed by and construed under the laws of the State of Delaware as applied to agreements entered into solely between residents of, and to be performed entirely within, such state.

[*Signature Page Follows*]

IN WITNESS WHEREOF, the undersigned has executed this Amendment to Limited Liability Company Agreement as of November 6, 2008.

ENTERPRISE GP HOLDINGS L.P.
(Sole Member of Enterprise Products GP, LLC)
By: EPE Holdings, LLC, its general partner

By: /s/ W. Randall Fowler
Name: W. Randall Fowler
Title: Executive Vice President and Chief Financial Officer

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Section 4: EX-31.1 (EXHIBIT 31.1)

EXHIBIT 31.1

CERTIFICATIONS

I, Michael A. Creel, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Enterprise Products Partners L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 10, 2008

/s/ Michael A. Creel
Name: Michael A. Creel
Title: Principal Executive Officer of our General Partner, Enterprise Products GP, LLC

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Section 5: EX-31.2 (EXHIBIT 31.2)

EXHIBIT 31.2

CERTIFICATIONS

I, W. Randall Fowler, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Enterprise Products Partners L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 10, 2008

/s/ W. Randall Fowler
Name: W. Randall Fowler
Title: Principal Financial Officer of our General Partner, Enterprise Products GP, LLC

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Section 6: EX-32.1 (EXHIBIT 32.1)

EXHIBIT 32.1

SARBANES-OXLEY SECTION 906 CERTIFICATION

CERTIFICATION OF MICHAEL A. CREEL, CHIEF EXECUTIVE OFFICER OF ENTERPRISE PRODUCTS GP, LLC, THE GENERAL PARTNER OF ENTERPRISE PRODUCTS PARTNERS L.P.

In connection with this quarterly report of Enterprise Products Partners L.P. (the "Registrant") on Form 10-Q for the quarterly period ended September 30, 2008 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Michael A. Creel, Chief Executive Officer of Enterprise Products GP, LLC, the general partner of the Registrant, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Registrant.

/s/ Michael A. Creel
Name: Michael A. Creel
Title: Chief Executive Officer of Enterprise

Products GP, LLC
on behalf of Enterprise Products Partners L.P.

Date: November 10, 2008

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Section 7: EX-32.2 (EXHIBIT 32.2)

EXHIBIT 32.2

SARBANES-OXLEY SECTION 906 CERTIFICATION

CERTIFICATION OF W. RANDALL FOWLER, CHIEF FINANCIAL OFFICER OF ENTERPRISE PRODUCTS GP, LLC, THE GENERAL PARTNER OF ENTERPRISE PRODUCTS PARTNERS L.P.

In connection with this quarterly report of Enterprise Products Partners L.P. (the “Registrant”) on Form 10-Q for the quarterly period ended September 30, 2008 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, W. Randall Fowler, Chief Financial Officer of Enterprise Products GP, LLC, the general partner of the Registrant, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Registrant.

/s/ W. Randall Fowler

Name: W. Randall Fowler
Title: Chief Financial Officer of Enterprise Products GP, LLC
on behalf of Enterprise Products Partners L.P.

Date: November 10, 2008
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EPD 10-K 12/31/2007

Section 1: 10-K (FORM 10-K - ANNUAL REPORT)

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2007

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from __ to __.

Commission file number: 1-14323

ENTERPRISE PRODUCTS PARTNERS L.P.
(Exact name of Registrant as Specified in Its Charter)

Delaware (State or Other Jurisdiction of Incorporation or Organization)	**76-0568219** (I.R.S. Employer Identification No.)
1100 Louisiana, 10th Floor, Houston, Texas (Address of Principal Executive Offices)	**77002** (Zip Code)

(713) 381-6500
(Registrant's Telephone Number, Including Area Code)

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange On Which Registered
Common Units	New York Stock Exchange

Securities to be registered pursuant to Section 12(g) of the Act: None.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes ☑ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
Yes ☐ No ☑

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes ☑ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer, or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☑ Accelerated filer ☐
Non-accelerated filer ☐ (Do not check if a smaller reporting company) Smaller Reporting Company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☑

The aggregate market value of the common units of *Enterprise Products Partners L.P.* ("EPD") held by non-affiliates at June 30, 2007, based on the closing price of such equity securities in the daily composite list for transactions on the New York Stock Exchange, was approximately $9.1 billion. This figure excludes common units beneficially owned by certain affiliates, including (i) Dan L. Duncan, (ii) Enterprise GP Holdings L.P. and (iii) certain trusts established for the benefit of Mr. Duncan's family. There were 435,297,303 common units of EPD outstanding at February 1, 2008.

ENTERPRISE PRODUCTS PARTNERS L.P.
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SIGNIFICANT RELATIONSHIPS REFERENCED IN THIS ANNUAL REPORT

Unless the context requires otherwise, references to "we," "us," "our," or "Enterprise Products Partners" are intended to mean the business and operations of Enterprise Products Partners L.P. and its consolidated subsidiaries.

References to "EPO" mean Enterprise Products Operating LLC as successor in interest by merger to Enterprise Products Operating L.P., which is a wholly owned subsidiary of Enterprise Products Partners through which Enterprise Products Partners conducts substantially all of its business.

References to "Duncan Energy Partners" mean Duncan Energy Partners L.P., which is a consolidated subsidiary of EPO. Duncan Energy Partners is a publicly traded Delaware limited partnership, the common units of which are listed on the New York Stock Exchange ("NYSE") under the ticker symbol "DEP." References to "DEP GP" mean DEP Holdings, LLC, which is the general partner of Duncan Energy Partners and is wholly owned by EPO.

References to "EPGP" mean Enterprise Products GP, LLC, which is our general partner.

References to "Enterprise GP Holdings" mean Enterprise GP Holdings L.P., a publicly traded affiliate, the units of which are listed on the NYSE under the ticker symbol "EPE." Enterprise GP Holdings owns Enterprise Products GP. References to "EPE Holdings" mean EPE Holdings, LLC, which is the general partner of Enterprise GP Holdings.

References to "TEPPCO" mean TEPPCO Partners, L.P., a publicly traded affiliate, the common units of which are listed on the NYSE under the ticker symbol "TPP." References to "TEPPCO GP" refer to Texas Eastern Products Pipeline Company, LLC, which is the general partner of TEPPCO and is wholly owned by Enterprise GP Holdings.

References to "Energy Transfer Equity" mean the business and operations of Energy Transfer Equity, L.P. and its consolidated subsidiaries, which include Energy Transfer Partners, L.P. ("ETP"). Energy Transfer Equity is a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol "ETE." The general partner of Energy Transfer Equity is LE GP, LLC ("LE GP"). On May 7, 2007, Enterprise GP Holdings acquired non-controlling interests in both LE GP and Energy Transfer Equity.

References to "Employee Partnerships" mean EPE Unit L.P. ("EPE Unit I"), EPE Unit II, L.P. ("EPE Unit II") and EPE Unit III, L.P. ("EPE Unit III"), collectively, which are private company affiliates of EPCO, Inc. See Note 25 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding the formation of Enterprise Unit L.P. in February 2008.

References to "EPCO" mean EPCO, Inc. and its wholly-owned private company affiliates, which are related party affiliates to all of the foregoing named entities.

We, EPO, Duncan Energy Partners, DEP GP, EPGP, Enterprise GP Holdings, EPE Holdings, TEPPCO and TEPPCO GP are affiliates under the common control of Dan L. Duncan, the Group Co-Chairman and controlling shareholder of EPCO.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This annual report contains various forward-looking statements and information that are based on our beliefs and those of our general partner, as well as assumptions made by us and information currently available to us. When used in this document, words such as "anticipate," "project," "expect," "plan," "seek," "goal," "forecast," "intend," "could," "should," "will," "believe," "may," "potential" and similar expressions and statements regarding our plans and objectives for future operations, are intended to identify forward-looking statements. Although we and our general partner believe that such expectations reflected in such forward-looking statements are reasonable, neither we nor our general partner can give any assurances that such expectations will prove to be correct. Such statements are subject to a variety of risks, uncertainties and assumptions as described in more detail in Item 1A of this annual report. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those anticipated, estimated, projected or expected. You should not put undue reliance on any forward-looking statements.

PART I

Items 1 and 2. *Business and Properties*.

General

We are a North American midstream energy company providing a wide range of services to producers and consumers of natural gas, natural gas liquids ("NGLs"), crude oil and certain petrochemicals. In addition, we are an industry leader in the development of pipeline and other midstream energy infrastructure in the continental United States and Gulf of Mexico. We conduct substantially all of our business through EPO. Our principal executive offices are located at 1100 Louisiana, 10th Floor, Houston, Texas 77002, our telephone number is (713) 381-6500 and our website is www.epplp.com.

We are a publicly traded Delaware limited partnership formed in 1998, the common units of which are listed on the NYSE under the ticker symbol "EPD." We are owned 98% by our limited partners and 2% by our general partner, EPGP. Our general partner is owned by a publicly traded affiliate, Enterprise GP Holdings, the common units of which are listed on the NYSE under the ticker symbol "EPE."

Business Strategy

We operate an integrated network of midstream energy assets that includes: natural gas gathering, treating, processing, transportation and storage; NGL fractionation (or separation), transportation, storage and import and export terminalling; crude oil transportation; offshore production platform services; and petrochemical transportation and services. Our business strategies are to:

- capitalize on expected increases in natural gas, NGL and crude oil production resulting from development activities in the Rocky Mountains and U.S. Gulf Coast regions, including the Gulf of Mexico;
- capitalize on expected demand growth for natural gas, NGLs, crude oil and refined products;
- maintain a diversified portfolio of midstream energy assets and expand this asset base through growth capital projects and accretive acquisitions of complementary midstream energy assets;
- share capital costs and risks through joint ventures or alliances with strategic partners, including those that will provide the raw materials for these growth projects or purchase the project's end products; and
- increase fee-based cash flows by investing in pipelines and other fee-based businesses.

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As noted above, part of our business strategy involves expansion through growth capital projects. We expect that these projects will enhance our existing asset base and provide us with additional growth opportunities in the future. For information regarding our growth capital projects, see "Capital Spending" included under Item 7 of this annual report.

Financial Information by Business Segment

For information regarding our business segments, see Note 16 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Recent Developments

For information regarding our recent developments, see "Overview of Business – Recent Developments" included under Item 7 of this annual report, which is incorporated by reference into this Item 1.

Segment Discussion

Our midstream energy asset network links producers of natural gas, NGLs and crude oil from some of the largest supply basins in the United States, Canada and the Gulf of Mexico with domestic consumers and international markets. We have four reportable business segments:

- NGL Pipelines & Services;
- Onshore Natural Gas Pipelines & Services;
- Offshore Pipelines & Services; and
- Petrochemical Services.

Our business segments are generally organized and managed according to the type of services rendered (or technologies employed) and products produced and/or sold.

The following sections present an overview of our business segments, including information regarding the principal products produced, services rendered, seasonality, competition and regulation. Our results of operations and financial condition are subject to a variety of risks. For information regarding our key risk factors, see Item 1A of this annual report.

Our business activities are subject to various federal, state and local laws and regulations governing a wide variety of topics, including commercial, operational, environmental, safety and other matters. For a discussion of the principal effects such laws and regulations have on our business, see "Regulation" and "Environmental and Safety Matters" included within this Item 1.

Our revenues are derived from a wide customer base. During 2007, 2006 and 2005, our largest customer was The Dow Chemical Company and its affiliates, which accounted for 6.9%, 6.1% and 6.8%, respectively, of our consolidated revenues.

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As generally used in the energy industry and in this document, the identified terms have the following meanings:

/d	= per day
BBtus	= billion British thermal units
Bcf	= billion cubic feet
MBPD	= thousand barrels per day
MMBbls	= million barrels
MMBtus	= million British thermal units
MMcf	= million cubic feet

The following discussion of our business segments provides information regarding our principal plants, pipelines and other assets. For information regarding our results of operations, including significant measures of historical throughput, production and processing rates, see Item 7 of this annual report.

NGL Pipelines & Services

Our NGL Pipelines & Services business segment includes our (i) natural gas processing business and related NGL marketing activities, (ii) NGL pipelines aggregating approximately 13,758 miles including our 7,808-mile Mid-America Pipeline System, (iii) NGL and related product storage facilities and (iv) NGL fractionation facilities located in Texas and Louisiana. This segment also includes our import and export terminal operations.

NGL products (ethane, propane, normal butane, isobutane and natural gasoline) are used as raw materials by the petrochemical industry, as feedstocks by refiners in the production of motor gasoline and by industrial and residential users as fuel. Ethane is primarily used in the petrochemical industry as a feedstock for ethylene production, one of the basic building blocks for a wide range of plastics and other chemical products. Propane is used both as a petrochemical feedstock in the production of ethylene and propylene and as a heating, engine and industrial fuel. Normal butane is used as a petrochemical feedstock in the production of ethylene and butadiene (a key ingredient of synthetic rubber), as a blendstock for motor gasoline and to derive isobutane through isomerization. Isobutane is fractionated from mixed butane (a mixed stream of normal butane and isobutane) or produced from normal butane through the process of isomerization, principally for use in refinery alkylation to enhance the octane content of motor gasoline, in the production of isooctane and other octane additives, and in the production of propylene oxide. Natural gasoline, a mixture of pentanes and heavier hydrocarbons, is primarily used as a blendstock for motor gasoline or as a petrochemical feedstock.

Natural gas processing and related NGL marketing activities. At the core of our natural gas processing business are 26 processing plants located in Colorado, Louisiana, Mississippi, New Mexico, Texas and Wyoming. Natural gas produced at the wellhead especially in association with crude oil contains varying amounts of NGLs. This "rich" natural gas in its raw form is usually not acceptable for transportation in the nation's major natural gas pipeline systems or for commercial use as a fuel. Natural gas processing plants remove the NGLs from the natural gas stream, enabling the natural gas to meet transmission pipeline and commercial quality specifications. In addition, on an energy equivalent basis, NGLs generally have a greater economic value as a raw material for petrochemical and motor gasoline production than their value as components of the natural gas stream. After extraction, we typically transport the mixed NGLs to a centralized facility for fractionation (or separation) into purity NGL products such as ethane, propane, normal butane, isobutane and natural gasoline. The purity NGL products can then be used in our NGL marketing activities to meet contractual requirements or sold on spot and forward markets.

When operating and extraction costs of natural gas processing plants are higher than the incremental value of the NGL products that would be extracted from a stream of natural gas, the recovery levels of certain NGL products, principally ethane, may be reduced or eliminated. This leads to a reduction in NGL volumes available for transportation and fractionation.

In our natural gas processing activities, we enter into margin-band contracts, percent-of-liquids contracts, percent-of-proceeds contracts, fee-based contracts, hybrid contracts (a combination of percent-of-liquids and fee-based contract terms) and keepwhole contracts. Under margin-band and keepwhole contracts, we take ownership of mixed NGLs extracted from the producer's natural gas stream and recognize revenue when the extracted NGLs are delivered and sold to customers on NGL marketing sales contracts. In the same way, revenue is recognized under our percent-of-liquids contracts except that the volume of NGLs we earn and sell is less than the total amount of NGLs extracted from the producers' natural gas. Under a percent-of-liquids contract, the producer retains title to the remaining percentage of mixed NGLs we extract and generally bears the natural gas cost for shrinkage and plant fuel. Under a percent-of-proceeds contract, we share in the proceeds generated from the sale of the mixed NGLs we extract on the producer's behalf. If a cash fee for natural gas processing services is stipulated by the contract, we record revenue when the natural gas has been processed and delivered to the producer. The NGL volumes we earn and take title to in connection with our processing activities are referred to as our equity NGL production.

In general, our percent-of-liquids, hybrid and keepwhole contracts give us the right (but not the obligation) to process natural gas for a producer; thus, we are protected from processing at an economic loss during times when the sum of our costs exceeds the value of the mixed NGLs of which we would take ownership. Generally, our natural gas processing agreements have terms ranging from month-to-month to life of the producing lease. Intermediate terms of one to ten years are also common.

To the extent that we are obligated under our margin-band and keepwhole gas processing contracts to compensate the producer for the natural gas equivalent energy value of mixed NGLs we extract from the natural gas stream, we are exposed to various risks, primarily commodity price fluctuations. However, our margin band contracts contain terms which limit our exposure to such risks. The prices of natural gas and NGLs are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control. Periodically, we attempt to mitigate these risks through the use of commodity financial instruments. For information regarding our use of commodity financial instruments, see "Quantitative and Qualitative Disclosures About Market Risks" included under Item 7A of this annual report.

Our NGL marketing activities generate revenues from the sale and delivery of NGLs obtained through our processing activities and purchases from third parties on the open market. These sales contracts may also include forward product sales contracts. In general, the sales prices referenced in these contracts are market-related and can include pricing differentials for such factors as delivery location.

NGL pipelines, storage facilities and import/export terminals. Our NGL pipeline, storage and terminalling operations include approximately 13,758 miles of NGL pipelines, 154.9 million barrels of working capacity for underground NGL and related product storage and two import/export facilities.

Our NGL pipelines transport mixed NGLs and other hydrocarbons from natural gas processing facilities, refineries and import terminals to fractionation plants and storage facilities; distribute and collect NGL products to and from petrochemical plants and refineries; and deliver propane to customers along the Dixie Pipeline and certain sections of the Mid-America Pipeline System. Revenue from our NGL pipeline transportation agreements is generally based upon a fixed fee per gallon of liquids transported multiplied by the volume delivered. Accordingly, the results of operations for this business are generally dependent upon the volume of product transported and the level of fees charged to customers (including those charged to our NGL and petrochemical marketing activities, which are eliminated in consolidation). The transportation fees charged under these arrangements are either contractual or regulated by governmental agencies, including the Federal Energy Regulatory Commission ("FERC"). Typically, we do not take title to the products transported in our NGL pipelines; rather, the shipper retains title and the associated commodity price risk.

Our NGL and related product storage facilities are integral parts of our operations. In general, our underground storage wells are used to store our and our customers' mixed NGLs, NGL products and petrochemical products. Under our NGL and related product storage agreements, we charge customers monthly storage reservation fees to reserve storage capacity in our underground caverns. The customers pay reservation fees based on the quantity of capacity reserved rather than the actual quantity utilized. When a customer exceeds its reserved capacity, we charge those customers an excess storage fee. In addition, we charge our customers throughput fees based on volumes injected and withdrawn from the storage facility. Accordingly, the profitability of our storage operations is dependent upon the level of capacity reserved by our customers, the volume of product injected and withdrawn from our underground caverns and the level of fees charged.

We operate NGL import and export facilities located on the Houston Ship Channel in southeast Texas. Our import facility is primarily used to offload volumes for delivery to our NGL storage and fractionation facilities near Mont Belvieu, Texas. Our export facility includes an NGL products chiller and related equipment used for loading refrigerated marine tankers for third-party export customers. Revenues from our import and export services are primarily based on fees per unit of volume loaded or unloaded and may also include demand payments. Accordingly, the profitability of our import and export activities primarily depends on the available quantities of NGLs to be loaded and offloaded and the fees we charge for these services.

NGL fractionation. We own or have interests in eight NGL fractionation facilities located in Texas and Louisiana. NGL fractionation facilities separate mixed NGL streams into purity NGL products. The three primary sources of mixed NGLs fractionated in the United States are (i) domestic natural gas processing plants, (ii) domestic crude oil refineries and (iii) imports of butane and propane mixtures. The mixed NGLs delivered from domestic natural gas processing plants and crude oil refineries to our NGL fractionation facilities are typically transported by NGL pipelines and, to a lesser extent, by railcar and truck.

Extraction of mixed NGLs by natural gas processing plants represents the largest source of volumes processed by our NGL fractionators. Based upon industry data, we believe that sufficient volumes of mixed NGLs, especially those originating from Gulf Coast and Rocky Mountain natural gas processing plants, will be available for fractionation in commercially viable quantities for the foreseeable future. Significant volumes of mixed NGLs are contractually committed to our NGL fractionation facilities by joint owners and third-party customers.

The majority of our NGL fractionation facilities process mixed NGL streams for third-party customers and support our NGL marketing activities under fee-based arrangements. These fees (typically in cents per gallon) are subject to adjustment for changes in certain fractionation expenses, including natural gas fuel costs. At our Norco facility, we perform fractionation services for certain customers under percent-of-liquids contracts. The results of operations of our NGL fractionation business are dependent upon the volume of mixed NGLs fractionated and either the level of fractionation fees charged (under fee-based contracts) or the value of NGLs received (under percent-of-liquids arrangements). We are exposed to fluctuations in NGL prices to the extent we fractionate volumes for customers under percent-of-liquids arrangements. Our fee-based customers generally retain title to the NGLs that we process for them.

Seasonality. Our natural gas processing and NGL fractionation operations exhibit little to no seasonal variation. Likewise, our NGL pipeline operations have not exhibited a significant degree of seasonality overall. However, propane transportation volumes are generally higher in the October through March timeframe in connection with increased use of propane for heating in the upper Midwest and southeastern United States. Our facilities located in the southern United States may be affected by weather events such as hurricanes and tropical storms originating in the Gulf of Mexico.

We operate our NGL and related product storage facilities based on the needs and requirements of our customers in the NGL, petrochemical, heating and other related industries. We usually experience an increase in the demand for storage services during the spring and summer months due to increased feedstock storage requirements for motor gasoline production and a decrease during the fall and winter months when propane inventories are being drawn for heating needs. In general, our import volumes peak during the spring and summer months and our export volumes are at their highest levels during the winter months.

In support of our commercial goals, our NGL marketing activities rely on inventories of mixed NGLs and purity NGL products. These inventories are the result of accumulated equity NGL production volumes, imports and other spot and contract purchases. Our inventories of ethane, propane and normal butane are typically higher on a seasonal basis from March through November as each are normally in higher demand and at higher price levels during winter months. Isobutane and natural gasoline inventories are generally stable throughout the year. Our inventory cycle begins in late-February to mid-March (the seasonal low point); builds through September; remains level until early December; before being drawn through winter until the seasonal low is reached again.

Competition. Our natural gas processing business and NGL marketing activities encounter competition from fully integrated oil companies, intrastate pipeline companies, major interstate pipeline companies and their non-regulated affiliates, and independent processors. Each of our competitors has varying levels of financial and personnel resources, and competition generally revolves around price, service and location.

In the markets served by our NGL pipelines, we compete with a number of intrastate and interstate liquids pipelines companies (including those affiliated with major oil, petrochemical and gas companies) and barge, rail and truck fleet operations. In general, our NGL pipelines compete with these entities in terms of transportation fees and service.

Our competitors in the NGL and related product storage businesses are integrated major oil companies, chemical companies and other storage and pipeline companies. We compete with other storage service providers primarily in terms of the fees charged, number of pipeline connections and operational dependability. Our import and export operations compete with those operated by major oil and chemical companies primarily in terms of loading and offloading volumes per hour.

We compete with a number of NGL fractionators in Texas, Louisiana and Kansas. Although competition for NGL fractionation services is primarily based on the fractionation fee charged, the ability of an NGL fractionator to receive mixed NGLs, store and distribute NGL products is also an important competitive factor and is a function of the existence of the necessary pipeline and storage infrastructure.

Properties. The following table summarizes the significant natural gas processing assets of our NGL Pipelines & Services business segment at February 1, 2008.

Description of Asset	Location(s)	Our Ownership Interest	Net Gas Processing Capacity (Bcf/d) (1)	Total Gas Processing Capacity (Bcf/d)
Natural gas processing facilities:				
Pioneer (2)	Wyoming	100%	1.35	1.35
Meeker (3)	Colorado	100%	0.75	0.75
Toca	Louisiana	63.9%	0.70	1.10
Chaco	New Mexico	100%	0.65	0.65
North Terrebonne	Louisiana	48.8%	0.63	1.30
Calumet	Louisiana	32.0%	0.51	1.60
Neptune	Louisiana	66%	0.43	0.65
Pascagoula	Mississippi	40%	0.40	1.50
Yscloskey	Louisiana	18.3%	0.34	1.85
Thompsonville	Texas	100%	0.30	0.30
Shoup	Texas	100%	0.29	0.29
Gilmore	Texas	100%	0.26	0.26
Armstrong	Texas	100%	0.25	0.25
Matagorda	Texas	100%	0.25	0.25
Others (11 facilities) (4)	Texas, New Mexico, Louisiana	Various (5)	1.27	3.44
Total processing capacities			8.38	15.54

(1) The approximate net natural gas processing capacity does not necessarily correspond to our ownership interest in each facility. It is based on a variety of factors such as volumes processed at the facility and ownership interest in the facility.

(2) We acquired a silica gel natural gas processing facility from TEPPCO in March 2006 and subsequently increased the processing capacity from 0.3 Bcf/d to 0.6 Bcf/d. In addition, we constructed a new cryogenic processing facility having 0.75 Bcf/d of processing capacity, which became operational in February 2008.

(3) In October 2007, we commenced natural gas processing operations at our Meeker facility. Phase II of the Meeker facility, which is under construction and expected to be completed in the third quarter of 2008, will double the natural gas processing capacity to 1.5 Bcf/d at this facility.

(4) Includes our Venice, Blue Water, Sea Robin and Burns Point facilities located in Louisiana; Indian Basin and Carlsbad facilities located in New Mexico; and San Martin, Delmita, Sonora, Shilling and Indian Springs facilities located in Texas. We acquired the Indians Springs facility in January 2005. Our ownership in the Venice plant is through our 13.1% equity method investment in Venice Energy Services Company, L.L.C. ("VESCO").

(5) Our ownership in these facilities ranges from 7.4% to 100%.

At the core of our natural gas processing business are 26 processing plants located in Texas, Louisiana, Mississippi, New Mexico, Colorado and Wyoming. Our natural gas processing facilities can be characterized as two distinct types: (i) straddle plants situated on mainline natural gas pipelines owned either by us or by third parties or (ii) field plants that process natural gas from gathering pipelines. We operate the Toca, Chaco, North Terrebonne, Calumet, Neptune, Carlsbad, Meeker and Pioneer plants and all of the Texas facilities. On a weighted-average basis, utilization rates for these assets were 63%, 56% and 53% during the years ended December 31, 2007, 2006 and 2005, respectively. These rates reflect the periods in which we owned an interest in such facilities.

Our NGL marketing activities utilize a fleet of approximately 445 railcars, the majority of which are leased. These railcars are used to deliver feedstocks to our facilities and to distribute NGLs throughout the United States and parts of Canada. We have rail loading and unloading facilities in Alabama, Arizona, California, Kansas, Louisiana, Minnesota, Mississippi, Nevada, North Carolina and Texas. These facilities service both our rail shipments and those of our customers.

The following table summarizes the significant NGL pipelines and related storage assets of our NGL Pipelines & Services business segment at February 1, 2008.

Description of Asset	Location(s)	Our Ownership Interest	Length (Miles)	Useable Storage Capacity (MMBbls)
NGL pipelines:				
Mid-America Pipeline System	Midwest and Western U.S.	100%	7,808	
Dixie Pipeline	South and Southeastern U.S.	74.2% (1)	1,371	
Seminole Pipeline	Texas	90% (2)	1,342	
EPD South Texas NGL System	Texas	100%	1,039	
Louisiana Pipeline System	Louisiana	Various (3)	612	
Promix NGL Gathering System	Louisiana	50%	364	
DEP South Texas NGL Pipeline System	Texas	100% (4)	286	
Houston Ship Channel	Texas	100%	266	
Lou-Tex NGL	Texas, Louisiana	100%	205	
Others (5 systems) (5)	Various	Various	465	
Total miles			13,758	
NGL and related product storage facilities by state:				
Texas (6)				124.5
Louisiana				15.3
Mississippi				5.7
Others (Arizona, Georgia, Iowa, Kansas, Nebraska, Oklahoma)				9.4
Total capacity (7)				154.9

(1) We hold a 74.2% interest in this system through a majority owned subsidiary, Dixie Pipeline Company ("Dixie").

(2) We hold a 90% interest in this system through a majority owned subsidiary, Seminole Pipeline Company ("Seminole").

(3) Of the 612 total miles for this system, we own 100% of 559 miles and 43.5% of the remaining 53 miles.

(4) Reflects consolidated ownership of this system by EPO (34%) and Duncan Energy Partners (66%).

(5) Includes our Tri-States, Belle Rose, Wilprise, and Chunchula pipelines located in the coastal regions of Alabama, Louisiana, and Mississippi and our Meeker pipeline in Colorado. We completed the Meeker pipeline in 2007, which transports NGLs from our Meeker natural gas processing facility to the Mid-America Pipeline System.

(6) The amount shown for Texas includes 33 underground caverns with an aggregate useable storage capacity of approximately 100 MMBbls that we own jointly with Duncan Energy Partners. These caverns are located in Mont Belvieu, Texas.

(7) The 154.9 MMBbls of total useable storage capacity includes 20.8 MMBbls held under operating leases. The leased facilities are located in Texas, Louisiana and Kansas.

The maximum number of barrels that our NGL pipelines can transport per day depends upon the operating balance achieved at a given point in time between various segments of the systems. Since the operating balance is dependent upon the mix of products to be shipped and demand levels at various delivery points, the exact capacities of our NGL pipelines cannot be determined. We measure the utilization rates of such pipelines in terms of net throughput (i.e., on a net basis in accordance with our ownership interest). Total net throughput volumes for these pipelines were 1,583 MBPD, 1,450 MBPD and 1,360 MBPD during the years ended December 31, 2007, 2006 and 2005, respectively.

The following information highlights the general use of each of our principal NGL pipelines. We operate our NGL pipelines with the exception of Tri-States and a small portion of the Louisiana Pipeline System.

- The *Mid-America Pipeline System* is a regulated NGL pipeline system consisting of three primary segments: the 2,785-mile Rocky Mountain pipeline, the 2,771-mile Conway North pipeline and the 2,252-mile Conway South pipeline. This system covers thirteen states: Wyoming, Utah, Colorado, New Mexico, Texas, Oklahoma, Kansas, Missouri, Nebraska, Iowa, Illinois, Minnesota and Wisconsin. The Rocky Mountain pipeline transports mixed NGLs from the Rocky Mountain Overthrust and San Juan Basin areas to the Hobbs hub located on the Texas-New Mexico border. During 2007, the Rocky Mountain pipeline's capacity was increased by 50 MBPD. The Conway North segment links the NGL hub at Conway, Kansas to refineries, petrochemical plants and propane markets in the upper Midwest. In addition, the

Conway North segment has access to NGL supplies from Canada's Western Sedimentary Basin through third-party connections. The Conway South pipeline, which completed an expansion in 2007, connects the Conway hub with Kansas refineries and transports NGLs to and from Conway, Kansas to the Hobbs hub. The Mid-America Pipeline System interconnects with our Seminole Pipeline and Hobbs NGL fractionator and storage facility at the Hobbs hub. We also own fifteen unregulated propane terminals that are an integral part of the Mid-America Pipeline System.

During 2007, approximately 51% of the volumes transported on the Mid-America Pipeline System were mixed NGLs originating from natural gas processing plants located in the Permian Basin in west Texas, the Hugoton Basin of southwestern Kansas, the San Juan Basin of northwest New Mexico, the Piceance Basin of Colorado, the Uintah Basin of Colorado and Utah and the Greater Green River Basin of southwestern Wyoming. The remaining volumes are generally purity NGL products originating from NGL fractionators in the mid-continent areas of Kansas, Oklahoma, and Texas, as well as deliveries from Canada.

- The *Dixie Pipeline* is a regulated propane pipeline extending from southeast Texas and Louisiana to markets in the southeastern United States. Propane supplies transported on this system primarily originate from southeast Texas, southern Louisiana and Mississippi. This system operates in seven states: Texas, Louisiana, Mississippi, Alabama, Georgia, South Carolina and North Carolina.

- The *Seminole Pipeline* is a regulated pipeline that transports NGLs from the Hobbs hub and the Permian Basin area of west Texas to markets in southeastern Texas. NGLs originating on the Mid-America Pipeline System are the primary source of throughput for the Seminole Pipeline.

- The *EPD South Texas NGL System* is a network of NGL gathering and transportation pipelines located in south Texas. The system includes 379 miles of pipeline used to gather and transport mixed NGLs from our south Texas natural gas processing facilities to our south Texas NGL fractionation facilities. The pipeline system also includes approximately 660 miles of pipelines that deliver NGLs from our south Texas fractionation facilities to refineries and petrochemical plants located between Corpus Christi and Houston, Texas and within the Texas City-Houston area, as well as to common carrier NGL pipelines.

- The *Louisiana Pipeline System* is a network of NGL pipelines located in Louisiana. This system transports NGLs originating in southern Louisiana and Texas to refineries and petrochemical companies along the Mississippi River corridor in southern Louisiana. This system also provides transportation services for our natural gas processing plants, NGL fractionators and other facilities located in Louisiana.

- The *Promix NGL Gathering System* is a NGL pipeline system that gathers mixed NGLs from natural gas processing plants in Louisiana for delivery to an NGL fractionator owned by K/D/S Promix, L.L.C. ("Promix"). This gathering system is an integral part of the Promix NGL fractionation facility. Our ownership interest in this pipeline is held indirectly through our equity method investment in Promix.

- The *DEP South Texas NGL Pipeline System* transports NGLs from our Shoup and Armstrong fractionation facilities in south Texas to Mont Belvieu, Texas. This system became operational in January 2007.

  We contributed a direct 66% equity interest in South Texas NGL Pipelines, LLC ("South Texas NGL"), our subsidiary that owns the DEP South Texas NGL Pipeline System, to Duncan Energy Partners effective February 1, 2007. We own the remaining 34% direct equity interest in South Texas NGL. For additional information regarding Duncan Energy Partners, see "Other Items – Initial Public Offering of Duncan Energy Partners" included under Item 7 of this annual report.

- The *Houston Ship Channel* pipeline system is a collection of pipelines extending from our Houston Ship Channel import/export facility and Morgan's Point facility to Mont Belvieu, Texas.

This system is used to deliver NGL products to third-party petrochemical plants and refineries as well as to deliver feedstocks to our Mont Belvieu facilities.

- The *Lou-Tex NGL* pipeline system is used to provide transportation services for NGLs and refinery grade propylene between the Louisiana and Texas markets. We also use this pipeline to transport mixed NGLs from certain of our Louisiana gas processing plants to our Mont Belvieu NGL fractionation facility.

Our NGL and related product storage facilities are integral parts of our pipeline and other operations. In general, these underground storage facilities are used to store NGLs and petrochemical products for us and our customers. Our underground storage facilities include locations in Arizona and Kansas that were acquired in July 2005. We operate these facilities, with the exception of certain storage locations operated for us by a third party in Louisiana.

We contributed a direct 66% equity interest in our subsidiary, Mont Belvieu Caverns, LLC ("Mont Belvieu Caverns"), to Duncan Energy Partners on February 5, 2007. We own the remaining 34% direct equity interest in Mont Belvieu Caverns. Mont Belvieu Caverns owns 33 underground storage caverns with an aggregate underground storage capacity of approximately 100 MMBbls, and a brine system with approximately 20 MMBbls of above-ground storage pit capacity and two brine production wells. These assets store and deliver NGLs (such as ethane and propane) and certain petrochemical products for industrial customers located along the upper Texas Gulf Coast. In 2007, we modified certain wells at our Mont Belvieu Caverns' facility to enable us to also store refined products such as motor gasoline and diesel fuel. For information regarding our ongoing Mont Belvieu storage well optimization projects, see "Liquidity and Capital Resources – Capital Spending" included under Item 7 of this annual report.

The following table summarizes the significant NGL fractionation assets of our NGL Pipelines & Services business segment at February 1, 2008.

Description of Asset	Location(s)	Our Ownership Interest	Net Plant Capacity (MBPD) (1)	Total Plant Capacity (MBPD)
NGL fractionation facilities:				
Mont Belvieu	Texas	75%	178	230
Shoup and Armstrong	Texas	100%	87	87
Hobbs	Texas	100%	75	75
Norco	Louisiana	100%	75	75
Promix	Louisiana	50%	73	145
BRF	Louisiana	32.2%	19	60
Tebone	Louisiana	43.5%	12	30
Total plant capacities			519	702

(1) The approximate net NGL fractionation capacity does not necessarily correspond to our ownership interest in each facility. It is based on a variety of factors such as volumes processed at the facility and ownership interest in the facility.

The following information highlights the general use of each of our principal NGL fractionation facilities. We operate all of our NGL fractionation facilities.

- Our *Mont Belvieu* NGL fractionation facility is located at Mont Belvieu, Texas, which is a key hub of the domestic and international NGL industry. This facility fractionates mixed NGLs from several major NGL supply basins in North America including the Mid-Continent, Permian Basin, San Juan Basin, Rocky Mountain Overthrust, East Texas and the Gulf Coast.

- Our *Shoup* and *Armstrong* NGL fractionation facilities fractionate mixed NGLs supplied by our south Texas natural gas processing plants. The Shoup and Armstrong facilities supply NGLs transported by the DEP South Texas NGL Pipeline System.

- The *Hobbs* NGL fractionation facility is located in Gaines County, Texas, where it serves petrochemical end users and refineries in West Texas, New Mexico and California. In addition, the Hobbs facility can supply exports to northern Mexico through existing pipeline infrastructure. The Hobbs facility receives mixed NGLs from several major supply basins including Mid-Continent, Permian Basin, San Juan Basin and the Rocky Mountain Overthrust. The facility is strategically located at the interconnect of our Mid-America Pipeline System and Seminole Pipeline, providing us flexibility to supply the nation's largest NGL hub at Mont Belvieu, Texas as well as access to the second-largest NGL hub at Conway, Kansas.

- The *Norco* NGL fractionation facility receives mixed NGLs via pipeline from refineries and natural gas processing plants located in southern Louisiana and along the Mississippi and Alabama Gulf Coast, including our Yscloskey, Pascagoula, Venice and Toca facilities.

- The *Promix* NGL fractionation facility receives mixed NGLs via pipeline from natural gas processing plants located in southern Louisiana and along the Mississippi Gulf Coast, including our Calumet, Neptune, Burns Point and Pascagoula facilities. In addition to the 364-mile Promix NGL Gathering System, Promix owns five NGL storage caverns and a barge loading facility that is integral to its operations.

- The *BRF* facility fractionates mixed NGLs from natural gas processing plants located in Alabama, Mississippi and southern Louisiana.

On a weighted-average basis, utilization rates for our NGL fractionators were 80%, 75% and 74% during the years ended December 31, 2007, 2006 and 2005, respectively. These rates reflect the periods in which we owned an interest in such facilities. We own direct consolidated interests in all of our NGL fractionation facilities with the exception of a 50% interest in a facility owned by Promix and a 32.2% interest in a facility owned by Baton Rouge Fractionators LLC ("BRF").

Our NGL operations include import and export facilities located on the Houston Ship Channel in southeast Texas. We own an import and export facility located on land we lease from Oiltanking Houston LP ("OTTI"). In June 2007, we completed an expansion of our OTTI facilities, which significantly increased our loading and offloading capabilities. Our OTTI import facility can now offload NGLs from tanker vessels at rates up to 20,000 barrels per hour depending on the product. Our OTTI export facility can now load cargoes of refrigerated propane and butane onto tanker vessels at rates up to 6,700 barrels per hour. Previously, our offloading rate was up to 10,000 barrels per hour (depending on product) and our maximum loading rate was 5,000 barrels per hour. In addition to our OTTI facilities, we own a barge dock that can load or offload two barges of NGLs or refinery-grade propylene simultaneously at rates up to 5,000 barrels per hour. Our average combined NGL import and export volumes were 84 MBPD, 127 MBPD and 119 MBPD for 2007, 2006 and 2005, respectively.

Onshore Natural Gas Pipelines & Services

Our Onshore Natural Gas Pipelines & Services business segment includes approximately 17,758 miles of onshore natural gas pipeline systems that provide for the gathering and transmission of natural gas in Alabama, Colorado, Louisiana, Mississippi, New Mexico, Texas and Wyoming. We own two salt dome natural gas storage facilities located in Mississippi and lease natural gas storage facilities located in Texas and Louisiana. This segment also includes our natural gas marketing activities.

Onshore natural gas pipelines and related natural gas marketing. Our onshore natural gas pipeline systems provide for the gathering and transmission of natural gas from onshore developments, such as the San Juan, Barnett Shale, Permian, Piceance and Greater Green River supply basins in the Western U.S., and from offshore developments in the Gulf of Mexico through connections with offshore pipelines. Typically, these systems receive natural gas from producers, other pipelines or shippers through system interconnects and redeliver the natural gas to processing facilities, local gas distribution companies, industrial or municipal customers or to other onshore pipelines.

Certain of our onshore natural gas pipelines generate revenues from transportation agreements where shippers are billed a fee per unit of volume transported (typically in MMBtus) multiplied by the volume delivered. The transportation fees charged under these arrangements are either contractual or regulated by governmental agencies, including the FERC. Intrastate natural gas pipelines (such as our Acadian Gas and Alabama Intrastate systems) may also purchase natural gas from producers and suppliers and resell such natural gas to customers such as electric utility companies, local natural gas distribution companies and industrial customers.

We entered the natural gas marketing business in 2001 when we acquired the Acadian Gas System. In 2007, we initiated an expansion of this marketing business to leverage off our other natural gas pipeline assets. Our natural gas marketing activities generate revenues from the sale and delivery of natural gas obtained primarily from (i) third party well-head purchases, (ii) our natural gas processing plants or (iii) the open market. In general, our natural gas sales contracts utilize market-based pricing and can incorporate pricing differentials for factors such as delivery location. We expect our natural gas marketing business to continue to grow in the future. Our consolidated revenues from this business were $1.6 billion, $1.2 billion and $1.1 billion for the years ended December 31, 2007, 2006 and 2005, respectively.

We are exposed to commodity price risk to the extent that we take title to natural gas volumes through our natural gas marketing activities or through certain contracts on our intrastate natural gas pipelines. In addition, our San Juan, Waha, Carlsbad and Jonah pipelines provide aggregating and bundling services, in which we purchase and resell natural gas for certain small producers. Also, several of our gathering systems, while not providing marketing services, have some exposure to risks related to commodity prices through transportation arrangements with shippers. For example, approximately 95% of the fee-based gathering arrangements of our San Juan Gathering System are calculated using a percentage of a regional price index for natural gas. We use commodity financial instruments from time to time to mitigate our exposure to risks related to commodity prices. For information regarding our use of commodity financial instruments, see "Quantitative and Qualitative Disclosures About Market Risks" included under Item 7A of this annual report.

Underground natural gas storage. We own two underground salt dome natural gas storage facilities located near Hattiesburg, Mississippi that are ideally situated to serve the domestic Northeast, Mid-Atlantic and Southeast natural gas markets. On a combined basis, these facilities (our Petal Gas Storage ("Petal") and Hattiesburg Gas Storage ("Hattiesburg") locations) are capable of delivering in excess of 1.4 Bcf/d of natural gas into five interstate pipeline systems. We also lease underground salt dome natural gas storage caverns that serve markets in Texas and Louisiana.

The ability of salt dome storage caverns to handle high levels of injections and withdrawals of natural gas benefits customers who desire the ability to meet load swings and to cover major supply interruption events, such as hurricanes and temporary losses of production. High injection and withdrawal rates also allow customers to take advantage of periods of volatile natural gas prices and respond in situations where they have natural gas imbalance issues on pipelines connected to the storage facilities. Our salt dome storage facilities permit sustained periods of high natural gas deliveries, including the ability to quickly switch from full injection to full withdrawal.

Under our natural gas storage contracts, there are typically two components of revenues: (i) monthly demand payments, which are associated with storage capacity reservation and paid regardless of the customer's usage, and (ii) storage fees per unit of volume stored at our facilities.

Seasonality. Typically, our onshore natural gas pipelines experience higher throughput rates during the summer months as natural gas-fired power generation facilities increase output to meet residential and commercial demand for electricity for air conditioning and in the winter months natural gas is needed as fuel for residential and commercial heating. Likewise, this seasonality also impacts the timing of injections and withdrawals at our natural gas storage facilities.

Competition. Within their market areas, our onshore natural gas pipelines compete with other onshore natural gas pipelines on the basis of price (in terms of transportation fees and/or natural gas selling prices), service and flexibility. Our competitive position within the onshore market is enhanced by our longstanding relationships with customers and the limited number of delivery pipelines connected (or capable of being economically connected) to the customers we serve.

Competition for natural gas storage is primarily based on location and the ability to deliver natural gas in a timely and reliable manner. Our natural gas storage facilities compete with other providers of natural gas storage, including other salt dome storage facilities and depleted reservoir facilities. We believe that the locations of our natural gas storage facilities allow us to compete effectively with other companies who provide natural gas storage services.

Properties. The following table summarizes the significant assets of our Onshore Natural Gas Pipelines & Services business segment at February 1, 2008.

Description of Asset	Location(s)	Our Ownership Interest	Length (Miles)	Approx. Net Capacity, Natural Gas (MMcf/d)	Gross Capacity (Bcf)
Onshore natural gas pipelines:					
Texas Intrastate System	Texas	100% (1)	6,976	5,155	
Piceance Creek Gathering System	Colorado	100%	48	1,600	
San Juan Gathering System	New Mexico, Colorado	100%	6,065	1,200	
Acadian Gas System	Louisiana	Various (2)	1,042	1,149	
Jonah Gathering System	Wyoming	19.4%	643	387	
Waha Gathering System	Texas, New Mexico	100%	465	380	
Carlsbad Gathering System	Texas, New Mexico	100%	919	220	
Alabama Intrastate System	Alabama	100%	408	200	
Encinal Gathering System	Texas	100%	449	143	
Other (6 systems) (3)	Texas, Mississippi	Various (4)	743		
Total miles			17,758		
Natural gas storage facilities:					
Petal	Mississippi	100%			14.1
Hattiesburg	Mississippi	100%			4.0
Wilson	Texas	Leased (5)			6.4
Acadian	Louisiana	Leased (6)			3.0
Total gross capacity					27.5

(1) We own a 50% undivided interest in the 641-mile Channel pipeline system, which is a component of the Texas Intrastate System. The remaining 50% is owned by affiliates of Energy Transfer Equity. In addition, we own less than a 100% undivided interest in certain segments of the Enterprise Texas pipeline system.

(2) Reflects consolidated ownership of Acadian Gas by EPO (34%) and Duncan Energy Partners (66%). Also includes the 49.5% equity investment that Acadian Gas has in the Evangeline pipeline.

(3) Includes the Delmita, Big Thicket, Indian Springs and Canales gathering systems located in Texas and the Petal and Hattiesburg pipelines located in Mississippi. The Delmita and Big Thicket gathering systems are integral parts of our natural gas processing operations, the results of operations and assets of which are accounted for under our NGL Pipelines & Services business segment. We acquired the Canales gathering system in connection with the Encinal acquisition in July 2006. The Petal and Hattiesburg pipelines are integral components of our natural gas storage operations.

(4) We own 100% of these assets with the exception of the Indian Springs system, in which we own an 80% undivided interest through a consolidated subsidiary.

(5) This facility is held under an operating lease that expires in January 2028.

(6) We hold this facility under an operating lease that expires in December 2012.

On a weighted-average basis, aggregate utilization rates for our onshore natural gas pipelines were approximately 64%, 71% and 73% during the years ended December 31, 2007, 2006 and 2005, respectively. The utilization rate for 2007 excludes our Piceance Creek Gathering System, which operated at an average utilization rate of 24% during 2007 as volumes ramped-up on this system. Our utilization rates reflect the periods in which we owned an interest in such assets, or, for recently constructed assets, since the dates such assets were placed into service.

The following information highlights the general use of each of our principal onshore natural gas pipelines and storage facilities, all of which we operate.

- The *Texas Intrastate System* gathers and transports natural gas from supply basins in Texas (from both onshore and offshore sources) to local gas distribution companies and electric generation and industrial and municipal consumers as well as to connections with intrastate and interstate pipelines. This system serves important natural gas producing regions and commercial markets in Texas, including Corpus Christi, the San Antonio/Austin area, the Beaumont/Orange area, the Houston area, and the Houston Ship Channel industrial market. The Texas Intrastate System is comprised of the 6,106-mile Enterprise Texas pipeline system, the 229-mile TPC Offshore gathering system and the 641-mile Channel pipeline system. The leased Wilson natural gas storage facility is an integral part of the Texas Intrastate System.

  In November 2006, we announced an expansion of our Texas Intrastate System with the construction of the Sherman Extension that will transport up to 1.1 Bcf/d of natural gas from the growing Barnett Shale area of North Texas. For information regarding this expansion projects, see "Liquidity and Capital Resources — Capital Spending" included under Item 7 of this annual report.

- The *Piceance Creek Gathering System* consists of a recently constructed natural gas gathering pipeline located in the Piceance Basin of northwestern Colorado. We acquired this pipeline from EnCana Oil & Gas ("EnCana") in December 2006. The Piceance Creek Gathering System extends from a connection with EnCana's Great Divide Gathering System located near Parachute, Colorado, northward through the heart of the Piceance Basin to our 1.5 Bcf/d Meeker natural gas treating and processing complex, which completed its first phase of construction in October 2007. We placed the Piceance Creek Gathering System into service in January 2007 and it currently transports approximately 520 MMcf/d of natural gas. With connectivity to EnCana's Great Divide Gathering System, our Piceance Creek Gathering System has access to natural gas production from the southern portion of the Piceance basin, including production from EnCana's Mamm Creek field.

- The *San Juan Gathering System* serves natural gas producers in the San Juan Basin of New Mexico and Colorado. This system gathers natural gas production from over 10,630 producing wells in the San Juan Basin and delivers the natural gas to natural gas processing facilities, including our Chaco facility.

  In November 2007, we and the Jicarilla Apache Nation announced the formation of a joint venture to own and operate natural gas gathering assets located on or near Jicarilla Apache Nation reservation lands. For additional information regarding this new joint venture, see "Recent Developments" included under Item 7 of this annual report.

- The *Acadian Gas System* purchases, transports, stores and sells natural gas in Louisiana. The Acadian Gas System is comprised of the 577-mile Cypress pipeline, 438-mile Acadian pipeline and the 27-mile Evangeline pipeline. The leased Acadian natural gas storage facility is an integral part of the Acadian Gas System.

  We contributed a direct 66% equity interest in Acadian Gas, LLC ("Acadian Gas"), which is a subsidiary that owns the Cypress and Acadian pipelines, to Duncan Energy Partners on February 5, 2007. We own the remaining 34% direct equity interest in Acadian Gas. For additional information regarding Duncan Energy Partners, see "Other Items — Initial Public Offering of Duncan Energy Partners" included under Item 7 of this annual report. Acadian Gas owns a 49.5% indirect interest in the Evangeline pipeline.

- The *Jonah Gathering System* is located in the Greater Green River Basin of southwestern Wyoming. This system gathers natural gas from the Jonah and Pinedale fields for delivery to regional natural gas processing plants, including our Pioneer facility, and major interstate

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pipelines. Our ownership in this gathering system is through our 19.4% equity method investment in Jonah Gas Gathering Company, which we acquired from TEPPCO in August 2006. We completed the first portion of the Phase V expansion the Jonah Gathering System in July 2007.

Currently the gross gathering capacity of this system is 2.0 Bcf/d (net to our interest, 387 MMcf/d) and is expected to increase to 2.4 Bcf/d upon the completion of the final stage of this expansion in April 2008. For additional information regarding this joint venture arrangement with TEPPCO, see Item 13 of this annual report.

- The *Waha and Carlsbad Gathering Systems* (formerly our Permian Basin System) gather natural gas from wells in the Permian Basin region of Texas and New Mexico and deliver natural gas into the El Paso Natural Gas, Transwestern and Oasis pipelines.

- The *Alabama Intrastate System* mainly gathers coal bed methane from wells in the Black Warrior Basin in Alabama. This system is also involved in the purchase, transportation and sale of natural gas.

- The *Encinal Gathering System* gathers natural gas from the Olmos and Wilcox formations in south Texas and delivers into our Texas Intrastate System, which delivers the natural gas into our south Texas facilities for processing. We acquired this gathering system in connection with the Encinal acquisition in July 2006.

- Our *Petal* and *Hattiesburg* underground storage facilities are strategically situated to serve the domestic Northeast, Mid-Atlantic and Southeast natural gas markets and are capable of delivering in excess of 1.4 Bcf/d of natural gas into five interstate pipeline systems.

We are developing a new natural gas storage cavern located at our Petal facility. The new cavern is designed to store approximately 7.9 Bcf of natural gas, of which approximately 5.0 Bcf will be working gas capacity and 2.9 Bcf will be the base gas requirements needed to support minimum pressures. This expansion project was approved by the FERC and is projected to commence operations during the second quarter of 2008. We have long-term, binding precedent agreements on the majority of the new capacity.

We are developing additional natural gas storage capacity at our Wilson facility. In addition, we are constructing various natural gas gathering pipelines and related assets in the Rocky Mountains region in support of long-term service agreements with major producers. For information regarding these expansion projects, see "Liquidity and Capital Resources — Capital Spending" included under Item 7 of this annual report.

Offshore Pipelines & Services

Our Offshore Pipelines & Services business segment includes (i) approximately 1,555 miles of offshore natural gas pipelines strategically located to serve production areas including some of the most active drilling and development regions in the Gulf of Mexico, (ii) approximately 914 miles of offshore Gulf of Mexico crude oil pipeline systems and (iii) six multi-purpose offshore hub platforms located in the Gulf of Mexico with crude oil or natural gas processing capabilities.

Offshore natural gas pipelines. Our offshore natural gas pipeline systems provide for the gathering and transmission of natural gas from production developments located in the Gulf of Mexico, primarily offshore Louisiana and Texas. Typically, these systems receive natural gas from producers, other pipelines and shippers through system interconnects and transport the natural gas to various downstream pipelines, including major interstate transmission pipelines that access multiple markets in the eastern half of the United States.

Our revenues from offshore natural gas pipelines are derived from fee-based agreements and are typically based on transportation fees per unit of volume transported (generally in MMBtus) multiplied by the volume delivered. These transportation agreements tend to be long-term in nature, often involving life-of-reserve commitments with firm and interruptible components. We do not take title to the natural gas volumes that are transported on our natural gas pipeline systems; rather, the shipper retains title and the associated commodity price risk.

Offshore oil pipelines. We own interests in several offshore oil pipeline systems, which are located in the vicinity of oil-producing areas in the Gulf of Mexico. Typically, these systems receive crude oil from offshore production developments, other pipelines or shippers through system interconnects and deliver the oil to either onshore locations or to other offshore interconnecting pipelines.

The majority of revenues from our offshore crude oil pipelines are derived from purchase and sale arrangements whereby we purchase oil from shippers at various receipt points along our crude oil pipelines for an index-based price (less a price differential) and sell the oil back to the shippers at various redelivery points at the same index-based price. Net revenue recognized from such arrangements is based on a price differential per unit of volume (typically in barrels) multiplied by the volume delivered. In addition, certain of our offshore crude oil pipelines generate revenues based upon a transportation fee per unit of volume (typically in barrels) multiplied by the volume delivered to the customer. A substantial portion of the revenues generated by our offshore crude oil pipeline systems are attributable to (i) production from reserves committed under long-term contracts for the productive life of the relevant field or (ii) contracts for the purchase and sale of crude oil with terms from two to twelve months. The revenues we earn for our services are dependent on the volume of crude oil to be delivered and the amount and term of the reserve commitment by the customer.

Offshore platforms. We have ownership interests in six multi-purpose offshore hub platforms located in the Gulf of Mexico with crude oil or natural gas processing capabilities. Offshore platforms are critical components of the offshore infrastructure in the Gulf of Mexico, supporting drilling and producing operations, and therefore play a key role in the overall development of offshore oil and natural gas reserves. Platforms are used to: (i) interconnect with the offshore pipeline grid; (ii) provide an efficient means to perform pipeline maintenance; (iii) locate compression, separation, production handling and other facilities; (iv) conduct drilling operations during the initial development phase of an oil and natural gas property; and (v) process off-lease production.

Revenues from offshore platform services generally consist of demand payments and commodity charges. Demand fees represent charges to customers served by our offshore platforms regardless of the volume the customer delivers to the platform. Revenues from commodity charges are based on a fixed-fee per unit of volume delivered to the platform (typically per MMcf of natural gas or per barrel of crude oil) multiplied by the total volume of each product delivered. Contracts for platform services often include both demand payments and commodity charges, but demand payments generally expire after a contractually fixed period of time and in some instances may be subject to cancellation by customers. Our Independence Hub and Marco Polo offshore platforms earn a significant amount of demand revenues. The Independence Hub platform will earn $55.2 million of demand revenues annually through March 2012. The Marco Polo platform will earn $25.2 million of demand revenues annually through April 2009.

Seasonality. Our offshore operations exhibit little to no effects of seasonality; however, they may be affected by weather events such as hurricanes and tropical storms in the Gulf of Mexico.

Competition. Within their market area, our offshore natural gas and oil pipelines compete with other pipelines (both regulated and unregulated systems) primarily on the basis of price (in terms of transportation fees), available capacity and connections to downstream markets. To a limited extent, our competition includes other offshore pipeline systems, built, owned and operated by producers to handle their own production and, as capacity is available, production for others. We compete with other platform service providers on the basis of proximity and access to existing reserves and pipeline systems, as well as costs and rates. Furthermore, our competitors may possess greater capital resources than we have available, which could enable them to address business opportunities more quickly than us.

Properties. The following table summarizes the significant assets of our Offshore Pipelines & Services business segment at February 1, 2008, all of which are located in the Gulf of Mexico primarily offshore Louisiana and Texas.

Description of Asset	Our Ownership Interest	Length (Miles)	Water Depth (Feet)	Approximate Net Capacity Natural Gas (MMcf/d)	Approximate Net Capacity Crude Oil (MPBD)
Offshore natural gas pipelines:					
High Island Offshore System	100%	291		1,800	
Viosca Knoll Gathering System	100%	172		1,000	
Independence Trail (1)	100%	134		1,000	
Green Canyon Laterals	Various (2)	95		599	
Anaconda Gathering System (3)	100%	137		550	
Phoenix Gathering System	100%	77		450	
Falcon Natural Gas Pipeline	100%	14		400	
Manta Ray Offshore Gathering System	25.7%	250		206	
Nautilus System	25.7%	101		154	
VESCO Gathering System	13.1%	260		105	
Nemo Gathering System	33.9%	24		102	
Total miles		1,555			
Offshore crude oil pipelines:					
Cameron Highway Oil Pipeline	50%	374			250
Poseidon Oil Pipeline System	36%	372			144
Allegheny Oil Pipeline	100%	43			140
Marco Polo Oil Pipeline	100%	37			120
Constitution Oil Pipeline	100%	67			80
Typhoon Oil Pipeline	100%	17			80
Tarantula Oil Pipeline	100%	4			30
Total miles		914			
Offshore platforms:					
Independence Hub (1)	80%		8,000	800	NA
Marco Polo	50%		4,300	150	60
Viosca Knoll 817	100%		671	145	5
Garden Banks 72	50%		518	40	18
East Cameron 373	100%		441	195	3
Falcon Nest	100%		389	400	3

(1) In July 2007, the Independence Hub platform and Independence Trail pipeline received first production from deepwater production wells connected to the Independence Hub platform. The Independence Hub platform began earning demand revenues in March 2007.

(2) Our ownership interests in the Green Canyon Laterals ranges from 0% to 100%.

(3) Data shown for the Anaconda Gathering System includes the 30-mile Constitution natural gas pipeline, which we constructed and placed into service in 2006. The Constitution natural gas pipeline has a net capacity of approximately 200 MMcf/d.

We operate our offshore natural gas pipelines, with the exception of the VESCO Gathering System, Manta Ray Offshore Gathering System, Nautilus System, Nemo Gathering System and certain components of the Green Canyon Laterals. On a weighted-average basis, aggregate utilization rates for our offshore natural gas pipelines were approximately 24%, 26% and 30% during the years ended December 31, 2007, 2006 and 2005, respectively. These rates reflect the periods in which we owned an interest in such assets.

The following information highlights the general use of each of our principal Gulf of Mexico offshore natural gas pipelines.

- The *High Island Offshore System* ("HIOS") transports natural gas from producing fields located in the Galveston, Garden Banks, West Cameron, High Island and East Breaks areas of the Gulf of Mexico to the ANR pipeline system, Tennessee Gas Pipeline and the U-T Offshore System. The HIOS pipeline system includes eight pipeline junction and service platforms. This system also includes the 86-mile East Breaks System that connects the Hoover-Diana deepwater platform located in Alaminos Canyon Block 25 to the HIOS pipeline system.

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- The *Viosca Knoll Gathering System* transports natural gas from producing fields located in the Main Pass, Mississippi Canyon and Viosca Knoll areas to several major interstate pipelines, including the Tennessee Gas, Columbia Gulf, Southern Natural, Transco, Dauphin Island Gathering System and Destin Pipelines.
- The *Independence Trail* natural gas pipeline transports natural gas from our Independence Hub platform to the Tennessee Gas Pipeline. Natural gas transported on the Independence Trail comes from production fields in the Atwater Valley, DeSoto Canyon, Lloyd Ridge and Mississippi Canyon areas of the Gulf of Mexico. This pipeline includes one pipeline junction platform at West Delta 68. We completed construction of the Independence Trail natural gas pipeline during 2006. In July 2007, the Independence Trail pipeline received first production from deepwater wells connected to the Independence Hub platform.
- The *Green Canyon Laterals* consist of 20 pipeline laterals (which are extensions of natural gas pipelines) that transport natural gas to downstream pipelines, including the HIOS.
- The *Anaconda Gathering System* connects our Marco Polo platform and the third-party owned Constitution platform to the ANR pipeline system. The Anaconda Gathering System includes our wholly-owned Typhoon, Marco Polo and Constitution natural gas pipelines. The Constitution natural gas pipeline serves the Constitution and Ticonderoga fields located in the central Gulf of Mexico.
- The *Phoenix Gathering System* connects the Red Hawk platform located in the Garden Banks area of the Gulf of Mexico to the ANR pipeline system.
- The *Falcon Natural Gas Pipeline* delivers natural gas processed at our Falcon Nest platform to a connection with the Central Texas Gathering System located on the Brazos Addition Block 133 platform.
- The *Manta Ray Offshore Gathering System* transports natural gas from producing fields located in the Green Canyon, Southern Green Canyon, Ship Shoal, South Timbalier and Ewing Bank areas of the Gulf of Mexico to numerous downstream pipelines, including our Nautilus System. Our ownership interest in this pipeline is held indirectly through our equity method investment in Neptune Pipeline Company, L.L.C. ("Neptune").
- The *Nautilus System* connects our Manta Ray Offshore Gathering System to our Neptune natural gas processing plant on the Louisiana gulf coast. Our ownership interest in this pipeline is held indirectly through our equity method investment in Neptune.
- The *VESCO Gathering System* is a 260-mile regulated natural gas pipeline system associated with the Venice natural gas processing plant in Louisiana. This pipeline is an integral part of the natural gas processing operations of VESCO. Our 13.1% interest in this system is held through our equity method investment in VESCO.
- The *Nemo Gathering System* transports natural gas from Green Canyon developments to an interconnect with our Manta Ray Offshore Gathering System. Our ownership interest in this pipeline is held indirectly through our equity method investment in Nemo Gathering Company, LLC.

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The following information highlights the general use of each of our principal Gulf of Mexico offshore crude oil pipelines, all of which we operate. On a weighted-average basis, aggregate utilization rates for our offshore crude oil pipelines were approximately 19%, 18% and 17% during the years ended December 31, 2007, 2006 and 2005, respectively. These rates reflect the periods in which we owned an interest in such assets.

- The *Cameron Highway Oil Pipeline* gathers crude oil production from deepwater areas of the Gulf of Mexico, primarily the South Green Canyon area, for delivery to refineries and terminals in southeast Texas. This pipeline includes one pipeline junction platform. Our 50% joint control ownership interest in this pipeline is held indirectly through our equity method investment in Cameron Highway Oil Pipeline Company ("Cameron Highway").

- The *Poseidon Oil Pipeline System* gathers production from the outer continental shelf and deepwater areas of the Gulf of Mexico for delivery to onshore locations in south Louisiana. This system includes one pipeline junction platform. Our ownership interest in this pipeline is held indirectly through our equity method investment in Poseidon Oil Pipeline Company, LLC.

- The *Allegheny Oil Pipeline* connects the Allegheny and South Timbalier 316 platforms in the Green Canyon area of the Gulf of Mexico with our Cameron Highway Oil Pipeline and Poseidon Oil Pipeline System.

- The *Marco Polo Oil Pipeline* transports crude oil from our Marco Polo platform to an interconnect with our Allegheny Oil Pipeline in Green Canyon Block 164.

- The *Constitution Oil Pipeline* serves the Constitution and Ticonderoga fields located in the central Gulf of Mexico. The Constitution Oil Pipeline connects with our Cameron Highway Oil Pipeline and Poseidon Oil Pipeline System at a pipeline junction platform.

In October 2006, we announced the execution of definitive agreements with producers to construct, own and operate an oil export pipeline that will provide firm gathering services from the BHP Billiton Plc-operated Shenzi production field located in the South Green Canyon area of the central Gulf of Mexico. For information regarding this project, see "Liquidity and Capital Resources — Capital Spending" included under Item 7 of this annual report.

The following information highlights the general use of each of our principal Gulf of Mexico offshore platforms. We operate these offshore platforms with the exception of the Marco Polo platform, Independence Hub platform and East Cameron 373.

On a weighted-average basis, utilization rates with respect to natural gas processing capacity of our offshore platforms were approximately 29%, 17% and 27% during the years ended December 31, 2007, 2006 and 2005, respectively. Likewise, utilization rates for our offshore platforms were approximately 26%, 19% and 9%, respectively, in connection with platform crude oil processing capacity. These rates reflect the periods in which we owned an interest in such assets. In addition to the offshore platforms we identified in the preceding table, we own or have an ownership interest in fourteen pipeline junction and service platforms. Our pipeline junction and service platforms do not have processing capacity.

- The *Independence Hub* platform is located in Mississippi Canyon Block 920. This platform processes natural gas gathered from production fields in the Atwater Valley, DeSoto Canyon, Lloyd Ridge and Mississippi Canyon areas of the Gulf of Mexico. We successfully installed the Independence Hub platform and began earning demand revenues in March 2007. In July 2007, the Independence Hub platform received first production from deepwater wells connected to the platform. Currently, the platform is receiving approximately 900 MMcf/d of natural gas from fifteen wells.

- The *Marco Polo* platform, which is located in Green Canyon Block 608, processes crude oil and natural gas from the Marco Polo, K2, K2 North and Genghis Khan fields. These fields are located

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in the South Green Canyon area of the Gulf of Mexico. Our 50% joint control ownership interest in this platform is held indirectly through our equity method investment in Deepwater Gateway, L.L.C.

- The *Viosca Knoll 817* platform is centrally located on our Viosca Knoll Gathering System. This platform primarily serves as a base for gathering deepwater production in the area, including the Ram Powell development.
- The *Garden Banks 72* platform serves as a base for gathering deepwater production from the Garden Banks Block 161 development and the Garden Banks Block 378 and 158 leases. This platform also serves as a junction platform for our Cameron Highway Oil Pipeline and Poseidon Oil Pipeline System.
- The *East Cameron 373* platform serves as the host for East Cameron Block 373 production and also processes production from Garden Banks Blocks 108, 152, 197, 200 and 201.
- The *Falcon Nest* platform, which is located in the Mustang Island Block 103 area of the Gulf of Mexico, currently processes natural gas from the Falcon field.

Petrochemical Services

Our Petrochemical Services business segment includes five propylene fractionation facilities, an isomerization complex, and an octane additive production facility. This segment also includes approximately 683 miles of petrochemical pipeline systems.

Propylene fractionation. Our propylene fractionation business consists primarily of five propylene fractionation facilities located in Texas and Louisiana, and approximately 613 miles of various propylene pipeline systems. These operations also include an export facility located on the Houston Ship Channel and our petrochemical marketing activities.

In general, propylene fractionation plants separate refinery grade propylene (a mixture of propane and propylene) into either polymer grade propylene or chemical grade propylene along with by-products of propane and mixed butane. Polymer grade propylene can also be produced from chemical grade propylene feedstock. Chemical grade propylene is also a by-product of olefin (ethylene) production. The demand for polymer grade propylene is attributable to the manufacture of polypropylene, which has a variety of end uses, including packaging film, fiber for carpets and upholstery and molded plastic parts for appliance, automotive, houseware and medical products. Chemical grade propylene is a basic petrochemical used in plastics, synthetic fibers and foams.

Results of operations for our polymer grade propylene plants are generally dependent upon toll processing arrangements and petrochemical marketing activities. These processing arrangements typically include a base-processing fee per gallon (or other unit of measurement) subject to adjustment for changes in natural gas, electricity and labor costs, which are the primary costs of propylene fractionation and isomerization operations. Our petrochemical marketing activities generate revenues from the sale and delivery of products obtained through our processing activities and purchases from third parties on the open market. In general, we sell our petrochemical products at market-related prices, which may include pricing differentials for such factors as delivery location.

As part of our petrochemical marketing activities, we have several long-term polymer grade propylene sales agreements. To meet our petrochemical marketing obligations, we have entered into several agreements to purchase refinery grade propylene. To limit the exposure of our petrochemical marketing activities to price risk, we attempt to match the timing and price of our feedstock purchases with those of the sales of end products.

Isomerization. Our isomerization business includes three butamer reactor units and eight associated deisobutanizer units located in Mont Belvieu, Texas, which comprise the largest commercial isomerization complex in the United States. In addition, this business includes a 70-mile pipeline system used to transport high-purity isobutane from Mont Belvieu, Texas to Port Neches, Texas.

Our commercial isomerization units convert normal butane into mixed butane, which is subsequently fractionated into normal butane, isobutane and high purity isobutane. The primary uses of isobutane are currently for the production of propylene oxide, isooctane and alkylate for motor gasoline. The demand for commercial isomerization services depends upon the industry's requirements for high purity isobutane and isobutane in excess of naturally occurring isobutane produced from NGL fractionation and refinery operations.

The results of operation of this business are generally dependent upon the volume of normal and mixed butanes processed and the level of toll processing fees charged to customers. Our isomerization facility provides processing services to meet the needs of third-party customers and our other businesses, including our NGL marketing activities and octane additive production facility.

Octane enhancement. We own and operate an octane additive production facility located in Mont Belvieu, Texas designed to produce isooctane, which is an additive used in reformulated motor gasoline blends to increase octane, and isobutylene. The facility produces isooctane and isobutylene using feedstocks of high-purity isobutane, which is supplied using production from our isomerization units. Prior to mid-2005, the facility produced methyl tertiary butyl ether ("MTBE"). We modified the facility to produce isooctane and isobutylene. Depending on the outcome of various factors, the facility may be further modified in the future to produce alkylate, another motor gasoline additive.

Seasonality. Overall, the propylene fractionation business exhibits little seasonality. Our isomerization operations experience slightly higher demand in the spring and summer months due to the demand for isobutane-based fuel additives used in the production of motor gasoline. Likewise, isooctane prices have been stronger during the April to September period of each year, which corresponds with the summer driving season.

Competition. We compete with numerous producers of polymer grade propylene, which include many of the major refiners and petrochemical companies on the Gulf Coast. Generally, the propylene fractionation business competes in terms of the level of toll processing fees charged and access to pipeline and storage infrastructure. Our petrochemical marketing activities encounter competition from fully integrated oil companies and various petrochemical companies. Our petrochemical marketing competitors have varying levels of financial and personnel resources and competition generally revolves around price, service, logistics and location.

In the isomerization market, we compete primarily with facilities located in Kansas, Louisiana and New Mexico. Competitive factors affecting this business include the level of toll processing fees charged, the quality of isobutane that can be produced and access to pipeline and storage infrastructure. We also compete with other octane additive manufacturing companies primarily on the basis of price.

Properties. The following table summarizes the significant assets of our Petrochemical Services segment at February 1, 2008, all of which we operate.

Description of Asset	Location(s)	Our Ownership Interest	Net Plant Capacity (MBPD)	Total Plant Capacity (MBPD)	Length (Miles)
Propylene fractionation facilities:					
Mont Belvieu (4 plants)	Texas	Various (1)	73	87	
BRPC	Louisiana	30% (2)	7	23	
Total capacity			80	110	
Isomerization facility:					
Mont Belvieu (3)	Texas	100%	116	116	
Petrochemical pipelines:					
Lou-Tex and Sabine Propylene	Texas, Louisiana	100% (4)			284
Texas City RGP Gathering System	Texas	100%			105
Lake Charles	Texas, Louisiana	50%			83
Others (6 systems) (5)	Texas	Various (6)			211
Total miles					683
Octane additive production facilities:					
Mont Belvieu	Texas	100%	12	12	

(1) We own a 54.6% interest and lease the remaining 45.4% of a facility having 17 MBPD of plant capacity. We own a 66.7% interest in a second facility having 41 MBPD of total plant capacity. We own 100% of the remaining two facilities, which have 14 MBPD and 15 MBPD of plant capacity, respectively.

(2) Our ownership interest in this facility is held indirectly through our equity method investment in Baton Rouge Propylene Concentrator LLC ("BRPC").

(3) On a weighted-average basis, utilization rates for this facility were approximately 78%, 70% and 70% during 2007, 2006 and 2005, respectively.

(4) Reflects consolidated ownership of these pipelines by EPO (34%) and Duncan Energy Partners (66%).

(5) Includes our Texas City PGP Delivery System and Port Neches, Bay Area, La Porte, Port Arthur and Bayport petrochemical pipelines.

(6) We own 100% of these pipelines with the exception of the 17-mile La Porte pipeline, in which we hold an aggregate 50% indirect interest through our equity method investments in La Porte Pipeline Company L.P. and La Porte Pipeline GP, L.L.C.

We produce polymer grade propylene at our Mont Belvieu location and chemical grade propylene at our BRPC facility. The primary purpose of the BRPC unit is to fractionate refinery grade propylene produced by an affiliate of ExxonMobil Corporation into chemical grade propylene. The production of polymer grade propylene from our Mont Belvieu plants is primarily used in our petrochemical marketing activities. On a weighted-average basis, aggregate utilization rates of our propylene fractionation facilities were approximately 86%, 86% and 83% during the years ended December 31, 2007, 2006 and 2005, respectively. This business segment also includes an above-ground polymer grade propylene storage and export facility located in Seabrook, Texas. This facility can load vessels at rates up to 5,000 barrels per hour.

The Lou-Tex propylene pipeline is used to transport chemical grade propylene from Sorrento, Louisiana to Mont Belvieu, Texas. The Sabine pipeline is used to transport polymer grade propylene from Port Arthur, Texas to a pipeline interconnect in Cameron Parish, Louisiana. We own these pipelines through our subsidiaries, Enterprise Lou-Tex Propylene Pipeline L.P. ("Lou-Tex Propylene") and Sabine Propylene Pipeline L.P. ("Sabine Propylene"). On February 5, 2007, we contributed a direct 66% equity interest in our subsidiaries that own the Lou-Tex Propylene and Sabine Propylene pipelines to Duncan Energy Partners. We own the remaining 34% direct interest in these subsidiaries. For additional information regarding Duncan Energy Partners, see "Other Items - Initial Public Offering of Duncan Energy Partners" included under Item 7 of this annual report.

The maximum number of barrels that our petrochemical pipelines can transport per day depends upon the operating balance achieved at a given point in time between various segments of the systems. Since the operating balance is dependent upon the mix of products to be shipped and demand levels at various delivery points, the exact capacities of our petrochemical pipelines cannot be determined. We measure the utilization rates of such pipelines in terms of net throughput (i.e., on a net basis in accordance with our ownership interest). Total net throughput volumes for these pipelines were 105 MBPD, 97 MBPD and 64 MBPD during the years ended December 31, 2007, 2006 and 2005, respectively.

Our octane additive facility currently has an isooctane production capacity of 12 MBPD. The facility was capable of producing only MTBE prior to mid-2005 at a rate up to 15.5 MBPD. On a weighted-average combined product basis, utilization rates for this facility were approximately 58%, 58% and 29% during the years ended December 31, 2007, 2006 and 2005, respectively.

Title to Properties

Our real property holdings fall into two basic categories: (i) parcels that we and our unconsolidated affiliates own in fee (e.g., we own the land upon which our Mont Belvieu NGL fractionator is constructed) and (ii) parcels in which our interests and those of our unconsolidated affiliates are derived from leases, easements, rights-of-way, permits or licenses from landowners or governmental authorities permitting the use of such land for our operations. The fee sites upon which our significant facilities are located have been owned by us or our predecessors in title for many years without any material challenge known to us relating to title to the land upon which the assets are located, and we believe that we have satisfactory title to such fee sites. We and our unconsolidated affiliates have no knowledge of any challenge to the underlying fee title of any material lease, easement, right-of-way, permit or license held by us or to our rights pursuant to any material lease, easement, right-of-way, permit or license, and we believe that we have satisfactory rights pursuant to all of our material leases, easements, rights-of-way, permits and licenses.

Capital Spending

We are committed to the long-term growth and viability of Enterprise Products Partners. Part of our business strategy involves expansion through business combinations, growth capital projects and investments in joint ventures. We believe we are positioned to continue to grow our system of assets through the construction of new facilities and to capitalize on expected future production increases from such areas as the Piceance Basin of western Colorado, the Greater Green River Basin in Wyoming, the Barnett Shale in North Texas, and the deepwater Gulf of Mexico. For a discussion of our capital spending program, see "Capital Spending" included under Item 7 of this annual report.

Regulation

Interstate Regulation

Liquids Pipelines. Certain of our crude oil and NGL pipeline systems (collectively referred to as "liquids pipelines") are interstate common carrier pipelines subject to regulation by the FERC under the Interstate Commerce Act ("ICA") and the Energy Policy Act of 1992 ("Energy Policy Act"). The ICA prescribes that interstate tariffs must be just and reasonable and must not be unduly discriminatory or confer any undue preference upon any shipper. FERC regulations require that interstate oil pipeline transportation rates be filed with the FERC and posted publicly.

The ICA permits interested persons to challenge proposed new or changed rates and authorizes the FERC to investigate such rates and to suspend their effectiveness for a period of up to seven months. If, upon completion of an investigation, the FERC finds that the new or changed rate is unlawful, it may require the carrier to refund the revenues in excess of the prior tariff during the term of the investigation. The FERC may also investigate, upon complaint or on its own motion, rates that are already in effect and may order a carrier to change its rates prospectively. Upon an appropriate showing, a shipper may obtain reparations for damages sustained for a period of up to two years prior to the filing of its complaint.

The Energy Policy Act deemed liquids pipeline rates that were in effect for the twelve months preceding enactment and that had not been subject to complaint, protest or investigation, just and reasonable under the Energy Policy Act (i.e., "grandfathered"). Some, but not all, our interstate liquids pipeline rates are considered grandfathered under the Energy Policy Act. Certain other rates for our interstate liquids pipeline services are charged pursuant to a FERC-approved indexing methodology, which allows a pipeline to charge rates up to a prescribed ceiling that changes annually based on the change from year-to-year in the Producer Price Index for finished goods ("PPI"). A rate increase within the indexed rate ceiling is presumed to be just and reasonable unless a protesting party can demonstrate that the rate increase is substantially in excess of the pipeline's costs. Effective March 21, 2006, FERC concluded that for the five-year period commencing July 1, 2006, liquids pipelines charging indexed rates may adjust their indexed ceilings annually by the PPI plus 1.3%.

As an alternative to using the indexing methodology, interstate liquids pipelines may elect to support rate filings by using a cost-of-service methodology, competitive market showings ("Market-Based Rates") or agreements with all of the pipeline's shippers that the rate is acceptable.

Because of the complexity of ratemaking, the lawfulness of any rate is never assured. The FERC uses prescribed rate methodologies for approving regulated tariff rates for transporting crude oil and refined products. These methodologies may limit our ability to set rates based on our actual costs or may delay the use of rates reflecting higher costs. Changes in the FERC's approved methodology for approving rates could adversely affect us. Adverse decisions by the FERC in approving our regulated rates could adversely affect our cash flow. Challenges to our tariff rates could be filed with the FERC. We believe the transportation rates currently charged by our interstate common carrier liquids pipelines are in accordance with the ICA. However, we cannot predict the rates we will be allowed to charge in the future for transportation services by such pipelines.

The Lou-Tex Propylene and Sabine Propylene pipelines are interstate common carrier pipelines regulated under the ICA by the Surface Transportation Board ("STB"), a part of the United States Department of Transportation. If the STB finds that a carrier's rates are not just and reasonable or are unduly discriminatory or preferential, it may prescribe a reasonable rate. In determining a reasonable rate, the STB will consider, among other factors, the effect of the rate on the volumes transported by that carrier, the carrier's revenue needs and the availability of other economic transportation alternatives.

The STB does not need to provide rate relief unless shippers lack effective competitive alternatives. If the STB determines that effective competitive alternatives are not available and a pipeline holds market power, then we may be required to show that our rates are reasonable.

Natural Gas Pipelines. Our interstate natural gas pipelines and storage facilities that provide services in interstate commerce are regulated by the FERC under the Natural Gas Act of 1938 ("NGA"). Under the NGA, the rates for service on these interstate facilities must be just and reasonable and not unduly discriminatory. We operate these interstate facilities pursuant to tariffs which set forth terms and conditions of service. These tariffs must be filed with and approved by the FERC pursuant to its regulations and orders. Our tariff rates may be lowered on a prospective basis only by the FERC, on its own initiative, or as a result of challenges to the rates by third parties if they are found unlawful. Unless the FERC grants specific authority to charge market-based rates, our rates are derived based on a cost-of-service methodology.

One element of the FERC's cost-of-service methodology as it affects partnerships such as ours is an income tax allowance. Pursuant to an order on remand of a decision by the U.S. Court of Appeals for the District of Columbia Circuit in *BP West Coast, LLC v. FERC* and a policy statement regarding income tax allowance issued by the FERC, the FERC will permit a pipeline to include in cost-of-service a tax allowance to reflect actual or potential tax liability on its public utility income attributable to all partnership or limited liability company interests if the ultimate owner of the interest has an actual or potential income tax liability on such income. Whether a pipeline's owners have such actual or potential income tax liability will be reviewed by the FERC on a case by case basis. Both the FERC's income tax allowance policy and its initial application in an individual pipeline proceeding were appealed to the United States Court of Appeals for the District of Columbia (the "D.C. Circuit"). In May 2007, the D.C. Circuit issued an opinion in ExxonMobil Oil Corporation, et al. v. FERC, which denied the appeals and upheld the FERC's tax allowance policy and the application of that policy in the individual pipeline proceeding. The FERC has issued additional orders reaffirming and clarifying its policy regarding the inclusion of an income tax allowance in rates. Most recently, the FERC issued an order in December 2007 which, among other things, affirmed the FERC's conclusion that the tax liability may be an actual or potential liability, further clarified its income tax allowance policy and concluded that the concept of a potential tax liability recognizes that tax liability may be deferred. However, the FERC left open the possibility that it could require different criteria before permitting an income tax allowance. Rehearing requests of the December 2007 order are pending at the FERC.

The FERC's authority over companies that provide natural gas pipeline transportation or storage services in interstate commerce also includes (i) certification, construction, and operation of certain new facilities; (ii) the acquisition, extension, disposition or abandonment of such facilities; (iii) the maintenance of accounts and records; (iv) the initiation, extension and termination of regulated services; and (v) various other matters. In addition, pursuant to the Energy Policy Act of 2005, the NGA and the Natural Gas Policy Act of 1978 ("NGPA") were amended to increase civil and criminal penalties for any violation of the NGA, NGPA and any rules, regulations or orders of the FERC up to $1 million per day per violation.

Offshore Pipelines. Our offshore natural gas gathering pipelines and crude oil pipeline systems are subject to federal regulation under the Outer Continental Shelf Lands Act ("OCSLA"), which requires that all pipelines operating on or across the outer continental shelf provide nondiscriminatory transportation service.

Intrastate Regulation

Our intrastate NGL and natural gas pipelines are subject to regulation in many states, including Alabama, Colorado, Louisiana, Mississippi, New Mexico and Texas. Certain of our intrastate pipelines are subject to limited regulation by the FERC under the NGPA as they provide transportation and storage service pursuant to Section 311 of the NGPA and the FERC's regulations. Under Section 311 of the NGPA, an intrastate pipeline company may transport gas for an interstate pipeline or any local distribution company served by an interstate pipeline. We are required to provide these services on an open and nondiscriminatory basis. The rates for 311 service may be established by the FERC or the respective state agency, but may not exceed a fair and equitable rate.

Certain other of our pipeline systems operate within a single state and provide intrastate pipeline transportation services. These pipeline systems are subject to various regulations and statutes mandated by state regulatory authorities. Although the applicable state statutes and regulations vary, they generally require that intrastate pipelines publish tariffs setting forth all rates, rules and regulations applying to intrastate service, and generally require that pipeline rates and practices be reasonable and nondiscriminatory. Shippers may also challenge our intrastate tariff rates and practices on our pipelines.

Sales of Natural Gas

We are engaged in natural gas marketing activities. The resale of natural gas in interstate commerce made by intrastate pipelines or their affiliates is subject to FERC regulation unless the gas is produced by the pipeline carrier or an affiliate. Under current federal rules, however, the price at which we sell natural gas currently is not regulated, insofar as the interstate market is concerned and, for the most part, is not subject to state regulation. The FERC's rules require pipelines and their marketing affiliates who sell natural gas in interstate commerce subject to the FERC's jurisdiction to adhere to a code of conduct prohibiting market manipulation and transactions that have no legitimate business purpose or result in prices not reflective of legitimate forces of supply and demand. Those who violate this code of conduct may be subject to suspension or loss of authorization to perform such sales, disgorgement of unjust profits, or other appropriate non-monetary remedies imposed by the FERC. The FERC currently has a rulemaking pending which would implement revisions to these rules. The FERC is continually proposing and implementing new rules and regulations affecting segments of the natural gas industry. We cannot predict the ultimate impact of these regulatory changes on our natural gas marketing activities; however, we believe that any new regulations will also be applied to other natural gas marketers with whom we compete.

Environmental and Safety Matters

General

Our operations are subject to multiple environmental obligations and potential liabilities under a variety of federal, state and local laws and regulations. These include, without limitation: the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Clean Air Act; the Federal Water Pollution Control Act or the Clean Water Act; the Oil Pollution Act; and analogous state and local laws and regulations. Such laws and regulations affect many aspects of our present and future operations, and generally require us to obtain and comply with a wide variety of environmental registrations, licenses, permits, inspections and other approvals, with respect to air emissions, water quality, wastewater discharges, and solid and hazardous waste management. Failure to comply with these requirements may expose us to fines, penalties and/or interruptions in our operations that could influence our results of operations. If an accidental leak, spill or release of hazardous substances occurs at a facility that we own, operate or otherwise use, or where we send materials for treatment or disposal, we could be held jointly and severally liable for all resulting liabilities, including investigation, remedial and clean-up costs. Likewise, we could be required to remove or remediate previously disposed wastes or property contamination, including groundwater contamination. Any or all of this could materially affect our results of operations and cash flows.

We believe our operations are in material compliance with applicable environmental and safety laws and regulations, other than certain matters discussed under Item 3 of this annual report, and that compliance with existing environmental and safety laws and regulations are not expected to have a material adverse effect on our financial position, results of operations or cash flows. Environmental and safety laws and regulations are subject to change. The clear trend in environmental regulation is to place more restrictions and limitations on activities that may be perceived to affect the environment, and thus there can be no assurance as to the amount or timing of future expenditures for environmental regulation compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate. Revised or additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from our customers, could have a material adverse effect on our business, financial position, results of operations and cash flows.

Water

The Federal Water Pollution Control Act of 1972, as renamed and amended as the Clean Water Act ("CWA"), and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into navigable waters of the United States, as well as state waters. Permits must be obtained to discharge pollutants into these waters. The CWA imposes substantial civil and criminal penalties for non-compliance. The EPA has promulgated regulations that require us to have permits in order to discharge storm water runoff. The EPA has entered into agreements with states in which we operate whereby the permits are administered by the respective states.

The primary federal law for oil spill liability is the Oil Pollution Act of 1990 ("OPA"), which addresses three principal areas of oil pollution — prevention, containment and cleanup, and liability. OPA subjects owners of certain facilities to strict, joint and potentially unlimited liability for containment and removal costs, natural resource damages and certain other consequences of an oil spill, where such spill is into navigable waters, along shorelines or in the exclusive economic zone of the U.S. Any unpermitted release of petroleum or other pollutants from our operations could also result in fines or penalties. OPA applies to vessels, offshore platforms and onshore facilities, including terminals, pipelines and transfer facilities. In order to handle, store or transport oil, shore facilities are required to file oil spill response plans with the United States Coast Guard, the United States Department of Transportation Office of Pipeline Safety ("OPS") or the EPA, as appropriate.

Some states maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. Contamination resulting from spills or releases of petroleum products is an inherent risk within our industry. To the extent that groundwater contamination requiring remediation exists along our pipeline systems as a result of past operation, we believe any such contamination could be controlled or remedied without having a material adverse effect on our financial position, but such costs are site specific and we cannot predict that the effect will not be material in the aggregate.

Air Emissions

Our operations are subject to the Federal Clean Air Act (the "Clean Air Act") and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including our facilities, and also impose various monitoring and reporting requirements. Such laws and regulations may require that we obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in the increase of existing air emissions, obtain and strictly comply with air permits containing various emissions and operational limitations, or utilize specific emission control technologies to limit emissions.

Our permits and related compliance obligations under the Clean Air Act, as well as recent or soon to be adopted changes to state implementation plans for controlling air emissions in regional, non-attainment areas, may require our operations to incur capital expenditures to add to or modify existing air emission control equipment and strategies. In addition, some of our facilities are included within the categories of hazardous air pollutant sources, which are subject to increasing regulation under the Clean Air

Act and many state laws. Our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations, and enforcement actions. We may be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions. We believe, however, that such requirements will not have a material adverse effect on our operations, and the requirements are not expected to be any more burdensome to us than to any other similarly situated companies.

Congress and some states are considering proposed legislation directed at reducing "greenhouse gas emissions." It is not possible at this time to predict how legislation that may be enacted to address greenhouse gas emissions would impact our business. However, future laws and regulations could result in increased compliance costs or additional operating restrictions, and could have a material adverse effect on our business, financial position, results of operations and cash flows.

Solid Waste

In our normal operations, we generate hazardous and non-hazardous solid wastes, including hazardous substances, that are subject to the requirements of the federal Resource Conservation and Recovery Act ("RCRA") and comparable state laws, which impose detailed requirements for the handling, storage treatment and disposal of hazardous and solid waste. We also utilize waste minimization and recycling processes to reduce the volumes of our waste. Amendments to RCRA required the EPA to promulgate regulations banning the land disposal of all hazardous wastes unless the waste meets certain treatment standards or the land-disposal method meets certain waste containment criteria. In the past, although we utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons and other materials may have been disposed of or released. In the future we may be required to remove or remediate these materials.

Environmental Remediation

The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as "Superfund," imposes liability, without regard to fault or the legality of the original act, on certain classes of persons who contributed to the release of a "hazardous substance" into the environment. These persons include the owner or operator of a facility where a release occurred, transporters that select the site of disposal of hazardous substances and companies that disposed of or arranged for the disposal of any hazardous substances found at a facility. Under CERCLA, these persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third parties to take actions in response to threats to the public health or the environment and to seek to recover the costs they incur from the responsible classes of persons. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. Despite the "petroleum exclusion" of CERCLA that currently encompasses natural gas, we may nonetheless handle "hazardous substances" subject to CERCLA in the course of our operations and our pipeline systems may generate wastes that fall within CERCLA's definition of a "hazardous substance." In the event a disposal facility previously used by us requires clean up in the future, we may be responsible under CERCLA for all or part of the costs required to clean up sites at which such wastes have been disposed.

Pipeline Safety Matters

We are subject to regulation by the United States Department of Transportation ("DOT") under the Accountable Pipeline and Safety Partnership Act of 1996, sometimes referred to as the Hazardous Liquid Pipeline Safety Act ("HLPSA"), and comparable state statutes relating to the design, installation, testing, construction, operation, replacement and management of our pipeline facilities. The HLPSA covers petroleum and petroleum products. The HLPSA requires any entity that owns or operates pipeline facilities to (i) comply with such regulations, (ii) permit access to and copying of records, (iii) file certain reports and

(iv) provide information as required by the Secretary of Transportation. We believe that we are in material compliance with these HLPSA regulations.

We are subject to the DOT regulation requiring qualification of pipeline personnel. The regulation requires pipeline operators to develop and maintain a written qualification program for individuals performing covered tasks on pipeline facilities. The intent of this regulation is to ensure a qualified work force and to reduce the probability and consequence of incidents caused by human error. The regulation establishes qualification requirements for individuals performing covered tasks. We believe that we are in material compliance with these DOT regulations.

We are also subject to the DOT Integrity Management regulations, which specify how companies should assess, evaluate, validate and maintain the integrity of pipeline segments that, in the event of a release, could impact High Consequence Areas ("HCAs"). HCAs are defined to include populated areas, unusually sensitive environmental areas and commercially navigable waterways. The regulation requires the development and implementation of an Integrity Management Program ("IMP") that utilizes internal pipeline inspection, pressure testing, or other equally effective means to assess the integrity of HCA pipeline segments. The regulation also requires periodic review of HCA pipeline segments to ensure adequate preventative and mitigative measures exist and that companies take prompt action to address integrity issues raised by the assessment and analysis. In compliance with these DOT regulations, we identified our HCA pipeline segments and have developed an IMP. We believe that the established IMP meets the requirements of these DOT regulations.

Risk Management Plans

We are subject to the EPA's Risk Management Plan ("RMP") regulations at certain facilities. These regulations are intended to work with the Occupational Safety and Health Act ("OSHA") Process Safety Management regulations (see "Safety Matters" below) to minimize the offsite consequences of catastrophic releases. The regulations required us to develop and implement a risk management program that includes a five-year accident history, an offsite consequence analysis process, a prevention program and an emergency response program. We believe we are operating in material compliance with our risk management program.

Safety Matters

Certain of our facilities are also subject to the requirements of the federal OSHA and comparable state statutes. We believe we are in material compliance with OSHA and state requirements, including general industry standards, record keeping requirements and monitoring of occupational exposures.

We are subject to OSHA Process Safety Management ("PSM") regulations, which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals. These regulations apply to any process which involves a chemical at or above the specified thresholds or any process which involves certain flammable liquid or gas. We believe we are in material compliance with the OSHA PSM regulations.

The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require us to organize and disclose information about the hazardous materials used in our operations. Certain parts of this information must be reported to employees, state and local governmental authorities and local citizens upon request.

Employees

Like many publicly traded partnerships, we have no employees. All of our management, administrative and operating functions are performed by employees of EPCO pursuant to an administrative services agreement. As of December 31, 2007, there were approximately 3,200 EPCO personnel that spend all or a portion of their time engaged in our business. Approximately 1,900 of these individuals devote all

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of their time performing management and operating duties for us. We reimburse EPCO for 100% of the costs it incurs to employ these individuals. The remaining approximate 1,300 personnel are part of EPCO's shared service organization and spend all or a portion of their time engaged in our business. The cost for their services is reimbursed to EPCO and is generally based on the percentage of time such employees perform services on our behalf during the year. For additional information regarding the administrative services agreement and our relationship with EPCO, see Note 17 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Available Information

As a large accelerated filer, we electronically file certain documents with the U.S. Securities and Exchange Commission ("SEC"). We file annual reports on Form 10-K; quarterly reports on Form 10-Q; and current reports on Form 8-K (as appropriate); along with any related amendments and supplements thereto. From time-to-time, we may also file registration statements and related documents in connection with equity or debt offerings. You may read and copy any materials we file with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington, DC 20549. You may obtain information regarding the Public Reference Room by calling the SEC at 1-800-SEC-0330. In addition, the SEC maintains an Internet website at www.sec.gov that contains reports and other information regarding registrants that file electronically with the SEC, including us.

We provide electronic access to our periodic and current reports on our Internet website, www.epplp.com. These reports are available as soon as reasonably practicable after we electronically file such materials with, or furnish such materials to, the SEC. You may also contact our investor relations department at (866) 230-0745 for paper copies of these reports free of charge.

Item 1A. *Risk Factors*.

An investment in our common units involves certain risks. If any of these risks were to occur, our business, results of operations, cash flows and financial condition could be materially adversely affected. In that case, the trading price of our common units could decline, and you could lose part or all of your investment.

The following section lists some, but not all, of the key risk factors that may have a direct impact on our business, results of operations, cash flows and financial condition.

Risks Relating to Our Business

Changes in demand for and production of hydrocarbon products may materially adversely affect our results of operations, cash flows and financial condition.

We operate predominantly in the midstream energy sector which includes gathering, transporting, processing, fractionating and storing natural gas, NGLs and crude oil. As such, our results of operations, cash flows and financial condition may be materially adversely affected by changes in the prices of these hydrocarbon products and by changes in the relative price levels among these hydrocarbon products. Changes in prices and changes in the relative price levels may impact demand for hydrocarbon products, which in turn may impact production, demand and volumes of product for which we provide services. We may also incur credit and price risk to the extent counterparties do not perform in connection with our marketing of natural gas, NGLs and propylene.

In the past, the price of natural gas has been extremely volatile, and we expect this volatility to continue. The NYMEX daily settlement price for natural gas for the prompt month contract in 2005 ranged from a high of \$15.38 per MMBtu to a low of \$5.79 per MMBtu. In 2006, the same index ranged from a high of \$10.63 per MMBtu to a low of \$4.20 per MMBtu. In 2007, the same index ranged from a high of \$8.64 per MMBtu to a low of \$5.38 per MMBtu.

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Generally, the prices of natural gas, NGLs, crude oil and other hydrocarbon products are subject to fluctuations in response to changes in supply, demand, market uncertainty and a variety of additional factors that are impossible to control. Some of these factors include:

- the level of domestic production and consumer product demand;
- the availability of imported oil and natural gas;
- actions taken by foreign oil and natural gas producing nations;
- the availability of transportation systems with adequate capacity;
- the availability of competitive fuels;
- fluctuating and seasonal demand for oil, natural gas and NGLs;
- the impact of conservation efforts;
- the extent of governmental regulation and taxation of production; and
- the overall economic environment.

We are exposed to natural gas and NGL commodity price risk under certain of our natural gas processing and gathering and NGL fractionation contracts that provide for our fees to be calculated based on a regional natural gas or NGL price index or to be paid in-kind by taking title to natural gas or NGLs. A decrease in natural gas and NGL prices can result in lower margins from these contracts, which may materially adversely affect our results of operations, cash flows and financial position.

A decline in the volume of natural gas, NGLs and crude oil delivered to our facilities could adversely affect our results of operations, cash flows and financial condition.

Our profitability could be materially impacted by a decline in the volume of natural gas, NGLs and crude oil transported, gathered or processed at our facilities. A material decrease in natural gas or crude oil production or crude oil refining, as a result of depressed commodity prices, a decrease in domestic and international exploration and development activities or otherwise, could result in a decline in the volume of natural gas, NGLs and crude oil handled by our facilities.

The crude oil, natural gas and NGLs currently transported, gathered or processed at our facilities originate from existing domestic and international resource basins, which naturally deplete over time. To offset this natural decline, our facilities will need access to production from newly discovered properties that are either being developed or expected to be developed. Exploration and development of new oil and natural gas reserves is capital intensive, particularly offshore in the Gulf of Mexico. Many economic and business factors are beyond our control and can adversely affect the decision by producers to explore for and develop new reserves. These factors could include relatively low oil and natural gas prices, cost and availability of equipment and labor, regulatory changes, capital budget limitations, the lack of available capital or the probability of success in finding hydrocarbons. For example, a sustained decline in the price of natural gas and crude oil could result in a decrease in natural gas and crude oil exploration and development activities in the regions where our facilities are located. This could result in a decrease in volumes to our offshore platforms, natural gas processing plants, natural gas, crude oil and NGL pipelines, and NGL fractionators, which would have a material adverse affect on our results of operations, cash flows and financial position. Additional reserves, if discovered, may not be developed in the near future or at all.

In addition, imported liquified natural gas ("LNG"), is expected to be a significant component of future natural gas supply to the United States. Much of this increase in LNG supplies is expected to be imported through new LNG facilities to be developed over the next decade. Twelve LNG projects have been approved by the FERC to be constructed in the Gulf Coast region and an additional two LNG projects

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have been proposed for the region. We cannot predict which, if any, of these projects will be constructed. We may not realize expected increases in future natural gas supply available to our facilities and pipelines if (i) a significant number of these new projects fail to be developed with their announced capacity, (ii) there are significant delays in such development, (iii) they are built in locations where they are not connected to our assets or (iv) they do not influence sources of supply on our systems. If the expected increase in natural gas supply through imported LNG is not realized, projected natural gas throughput on our pipelines would decline, which could have a material adverse effect on our results of operations, cash flows and financial position.

A decrease in demand for NGL products by the petrochemical, refining or heating industries could materially adversely affect our results of operations, cash flows and financial position.

A decrease in demand for NGL products by the petrochemical, refining or heating industries, whether because of general economic conditions, reduced demand by consumers for the end products made with NGL products, increased competition from petroleum-based products due to pricing differences, adverse weather conditions, government regulations affecting prices and production levels of natural gas or the content of motor gasoline or other reasons, could materially adversely affect our results of operations, cash flows and financial position. For example:

Ethane. Ethane is primarily used in the petrochemical industry as feedstock for ethylene, one of the basic building blocks for a wide range of plastics and other chemical products. If natural gas prices increase significantly in relation to NGL product prices or if the demand for ethylene falls (and, therefore, the demand for ethane by NGL producers falls), it may be more profitable for natural gas producers to leave the ethane in the natural gas stream to be burned as fuel than to extract the ethane from the mixed NGL stream for sale as an ethylene feedstock.

Propane. The demand for propane as a heating fuel is significantly affected by weather conditions. Unusually warm winters could cause the demand for propane to decline significantly and could cause a significant decline in the volumes of propane that we transport.

Isobutane. A reduction in demand for motor gasoline additives may reduce demand for isobutane. During periods in which the difference in market prices between isobutane and normal butane is low or inventory values are high relative to current prices for normal butane or isobutane, our operating margin from selling isobutane could be reduced.

Propylene. Propylene is sold to petrochemical companies for a variety of uses, principally for the production of polypropylene. Propylene is subject to rapid and material price fluctuations. Any downturn in the domestic or international economy could cause reduced demand for, and an oversupply of propylene, which could cause a reduction in the volumes of propylene that we transport.

We face competition from third parties in our midstream businesses.

Even if reserves exist in the areas accessed by our facilities and are ultimately produced, we may not be chosen by the producers in these areas to gather, transport, process, fractionate, store or otherwise handle the hydrocarbons that are produced. We compete with others, including producers of oil and natural gas, for any such production on the basis of many factors, including but not limited to:

- geographic proximity to the production;
- costs of connection;
- available capacity;
- rates; and
- access to markets.

Our future debt level may limit our flexibility to obtain additional financing and pursue other business opportunities.

As of December 31, 2007, we had approximately $6.90 billion of consolidated debt outstanding including Duncan Energy Partners, which had approximately $200.0 million outstanding under its credit facility. The amount of our future debt could have significant effects on our operations, including, among other things:

- a substantial portion of our cash flow, including that of Duncan Energy Partners, could be dedicated to the payment of principal and interest on our future debt and may not be available for other purposes, including the payment of distributions on our common units and capital expenditures;
- credit rating agencies may view our debt level negatively;
- covenants contained in our existing and future credit and debt arrangements will require us to continue to meet financial tests that may adversely affect our flexibility in planning for and reacting to changes in our business, including possible acquisition opportunities;
- our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or such financing may not be available on favorable terms;
- we may be at a competitive disadvantage relative to similar companies that have less debt; and
- we may be more vulnerable to adverse economic and industry conditions as a result of our significant debt level.

Our public debt indentures currently do not limit the amount of future indebtedness that we can create, incur, assume or guarantee. Although EPO's Multi-Year Revolving Credit Facility restricts our ability to incur additional debt above certain levels, any debt we may incur in compliance with these restrictions may still be substantial. For information regarding EPO's Multi-Year Revolving Credit Facility, see Note 14 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

EPO's Multi-Year Revolving Credit Facility and each of its indentures for public debt contain conventional financial covenants and other restrictions. For example, we are prohibited from making distributions to our partners if such distributions would cause an event of default or otherwise violate a covenant under EPO's Multi-Year Revolving Credit Facility. In addition, under the terms of our junior subordinated notes, generally, if we elect to defer interest payments thereon, we are restricted from making distributions with respect to our equity securities. A breach of any of these restrictions by us could permit our lenders or noteholders, as applicable, to declare all amounts outstanding under these debt agreements to be immediately due and payable and, in the case of EPO's Multi-Year Revolving Credit Facility, to terminate all commitments to extend further credit. For additional information regarding EPO's Multi-Year Revolving Credit Facility, see Note 14 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Our ability to access capital markets to raise capital on favorable terms will be affected by our debt level, the amount of our debt maturing in the next several years and current maturities, and by prevailing market conditions. Moreover, if the rating agencies were to downgrade our credit ratings, then we could experience an increase in our borrowing costs, difficulty assessing capital markets or a reduction in the market price of our common units. Such a development could adversely affect our ability to obtain financing for working capital, capital expenditures or acquisitions or to refinance existing indebtedness. If we are unable to access the capital markets on favorable terms in the future, we might be forced to seek extensions for some of our short-term securities or to refinance some of our debt obligations through bank credit, as opposed to long-term public debt securities or equity securities. The price and terms upon which we might receive such extensions or additional bank credit, if at all, could be more onerous than those contained in existing debt agreements. Any such arrangements could, in turn, increase the risk that our leverage may adversely affect our future financial and operating flexibility and thereby impact our ability to pay cash distributions at expected rates.

We may not be able to fully execute our growth strategy if we encounter illiquid capital markets or increased competition for investment opportunities.

Our strategy contemplates growth through the development and acquisition of a wide range of midstream and other energy infrastructure assets while maintaining a strong balance sheet. This strategy includes constructing and acquiring additional assets and businesses to enhance our ability to compete effectively and diversifying our asset portfolio, thereby providing more stable cash flow. We regularly consider and enter into discussions regarding, and are currently contemplating and/or pursuing, potential joint ventures, stand alone projects or other transactions that we believe will present opportunities to realize synergies, expand our role in the energy infrastructure business and increase our market position.

We will require substantial new capital to finance the future development and acquisition of assets and businesses. Any limitations on our access to capital will impair our ability to execute this strategy. If the cost of such capital becomes too expensive, our ability to develop or acquire accretive assets will be limited. We may not be able to raise the necessary funds on satisfactory terms, if at all. The primary factors that influence our initial cost of equity include market conditions, fees we pay to underwriters and other offering costs, which include amounts we pay for legal and accounting services. The primary factors influencing our cost of borrowing include interest rates, credit spreads, covenants, underwriting or loan origination fees and similar charges we pay to lenders.

In addition, we are experiencing increased competition for the types of assets and businesses we have historically purchased or acquired. Increased competition for a limited pool of assets could result in our losing to other bidders more often or acquiring assets at less attractive prices. Either occurrence would limit our ability to fully execute our growth strategy. Our inability to execute our growth strategy may materially adversely affect our ability to maintain or pay higher distributions in the future.

Our operating cash flows from our capital projects may not be immediate.

We are engaged in several construction projects involving existing and new facilities for which we have expended or will expend significant capital, and our operating cash flow from a particular project may not increase until a period of time after its completion. For instance, if we build a new pipeline or platform or expand an existing facility, the design, construction, development and installation may occur over an extended period of time, and we may not receive any material increase in operating cash flow from that project until a period of time after it is placed in service. If we experience any unanticipated or extended delays in generating operating cash flow from these projects, we may be required to reduce or reprioritize our capital budget, sell non-core assets, access the capital markets or decrease or limit distributions to unitholders in order to meet our capital requirements.

Our growth strategy may adversely affect our results of operations if we do not successfully integrate the businesses that we acquire or if we substantially increase our indebtedness and contingent liabilities to make acquisitions.

Our growth strategy includes making accretive acquisitions. As a result, from time to time, we will evaluate and acquire assets and businesses (either ourselves or Duncan Energy Partners may do so) that we believe complement our existing operations. We may be unable to integrate successfully businesses we acquire in the future. We may incur substantial expenses or encounter delays or other problems in connection with our growth strategy that could negatively impact our results of operations, cash flows and financial condition.

Moreover, acquisitions and business expansions involve numerous risks, including but not limited to:

- difficulties in the assimilation of the operations, technologies, services and products of the acquired companies or business segments;
- establishing the internal controls and procedures that we are required to maintain under the Sarbanes-Oxley Act of 2002;
- managing relationships with new joint venture partners with whom we have not previously partnered;
- inefficiencies and complexities that can arise because of unfamiliarity with new assets and the businesses associated with them, including with their markets; and
- diversion of the attention of management and other personnel from day-to-day business to the development or acquisition of new businesses and other business opportunities.

If consummated, any acquisition or investment would also likely result in the incurrence of indebtedness and contingent liabilities and an increase in interest expense and depreciation, accretion and amortization expenses. As a result, our capitalization and results of operations may change significantly following an acquisition. A substantial increase in our indebtedness and contingent liabilities could have a material adverse effect on our results of operations, cash flows and financial condition. In addition, any anticipated benefits of a material acquisition, such as expected cost savings, may not be fully realized, if at all.

Acquisitions that appear to be accretive may nevertheless reduce our cash from operations on a per unit basis.

Even if we make acquisitions that we believe will be accretive, these acquisitions may nevertheless reduce our cash from operations on a per unit basis. Any acquisition involves potential risks, including, among other things:

- mistaken assumptions about volumes, revenues and costs, including synergies;
- an inability to integrate successfully the businesses we acquire;
- decrease in our liquidity as a result of our using a significant portion of our available cash or borrowing capacity to finance the acquisition;
- a significant increase in our interest expense or financial leverage if we incur additional debt to finance the acquisition;
- the assumption of unknown liabilities for which we are not indemnified or for which our indemnity is inadequate;
- an inability to hire, train or retain qualified personnel to manage and operate our growing business and assets;
- limitations on rights to indemnity from the seller;
- mistaken assumptions about the overall costs of equity or debt;
- the diversion of management's and employees' attention from other business concerns;
- unforeseen difficulties operating in new product areas or new geographic areas; and

- customer or key employee losses at the acquired businesses.

If we consummate any future acquisitions, our capitalization and results of operations may change significantly, and you will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in determining the application of these funds and other resources.

Our actual construction, development and acquisition costs could exceed forecasted amounts.

We have significant expenditures for the development and construction of midstream energy infrastructure assets, including construction and development projects with significant logistical, technological and staffing challenges. We may not be able to complete our projects at the costs we estimated at the time of each project's initiation or that we currently estimate. For example, material and labor costs associated with our projects in the Rocky Mountains region increased over time due to factors such as higher transportation costs and the availability of construction personnel. Similarly, force majeure events such as hurricanes along the Gulf Coast may cause delays, shortages of skilled labor and additional expenses for these construction and development projects, as were experienced with Hurricanes Katrina and Rita during 2005.

Our construction of new assets is subject to regulatory, environmental, political, legal and economic risks, which may result in delays, increased costs or decreased cash flows.

One of the ways we intend to grow our business is through the construction of new midstream energy assets. The construction of new assets involves numerous operational, regulatory, environmental, political and legal risks beyond our control and may require the expenditure of significant amounts of capital. These potential risks include, among other things, the following:

- we may be unable to complete construction projects on schedule or at the budgeted cost due to the unavailability of required construction personnel or materials, accidents, weather conditions or an inability to obtain necessary permits;
- we will not receive any material increases in revenues until the project is completed, even though we may have expended considerable funds during the construction phase, which may be prolonged;
- we may construct facilities to capture anticipated future growth in production in a region in which such growth does not materialize;
- since we are not engaged in the exploration for and development of natural gas reserves, we may not have access to third-party estimates of reserves in an area prior to our constructing facilities in the area. As a result, we may construct facilities in an area where the reserves are materially lower than we anticipate;
- where we do rely on third-party estimates of reserves in making a decision to construct facilities, these estimates may prove to be inaccurate because there are numerous uncertainties inherent in estimating reserves; and
- we may be unable to obtain rights-of-way to construct additional pipelines or the cost to do so may be uneconomical.

A materialization of any of these risks could adversely affect our ability to achieve growth in the level of our cash flows or realize benefits from expansion opportunities or construction projects.

We may not be able to consummate future public offerings of Duncan Energy Partners' debt and equity securities on terms that we expect or at all, which would result in less cash available for us to fund our capital spending program.

Duncan Energy Partners was formed in part to acquire, own and operate midstream energy businesses of ours. In the future, we may contribute additional equity interests in our subsidiaries to Duncan Energy Partners and use the proceeds we receive from Duncan Energy Partners to fund our capital spending program. Although Duncan Energy Partners successfully completed its initial public offering of partnership units in February 2007, there is no guarantee that, in the event of a proposed future contribution, Duncan Energy Partners will be able to complete future offerings of its securities in amounts that we would expect. If this occurs, we may have less cash available to fund our capital spending program, which could result in less cash distributions.

Substantially all of the common units in us that are owned by EPCO and its affiliates are pledged as security under EPCO's credit facility. Additionally, all of the member interests in our general partner and all of the common units in us that are owned by Enterprise GP Holdings are pledged under its credit facility. Upon an event of default under either of these credit facilities, a change in ownership or control of us could ultimately result.

An affiliate of EPCO has pledged substantially all of its common units in us as security under its credit facility. EPCO's credit facility contains customary and other events of default relating to defaults of EPCO and certain of its subsidiaries, including certain defaults by us and other affiliates of EPCO. An event of default, followed by a foreclosure on EPCO's pledged collateral, could ultimately result in a change in ownership of us. In addition, the 100% membership interest in our general partner and the 13,454,498 of our common units that are owned by Enterprise GP Holdings are pledged under Enterprise GP Holdings' credit facility. Enterprise GP Holdings' credit facility contains customary and other events of default. Upon an event of default, the lenders under Enterprise GP Holdings' credit facility could foreclose on Enterprise GP Holdings' assets, which could ultimately result in a change in control of our general partner and a change in the ownership of our units held by Enterprise GP Holdings.

The credit and risk profile of our general partner and its owners could adversely affect our credit ratings and profile.

The credit and business risk profiles of the general partner or owners of a general partner may be factors in credit evaluations of a limited partnership by the nationally recognized debt rating agencies. This is because the general partner can exercise significant influence over the business activities of the partnership, including its cash distribution and acquisition strategy and business risk profile. Another factor that may be considered is the financial condition of the general partner and its owners, including the degree of their financial leverage and their dependence on cash flow from the partnership to service their indebtedness.

Entities controlling the owner of our general partner have significant indebtedness outstanding and are dependent principally on the cash distributions from their limited partner equity interests in us, Enterprise GP Holdings and TEPPCO to service such indebtedness. Any distributions by us, Enterprise GP Holdings and TEPPCO to such entities will be made only after satisfying our then current obligations to creditors. Although we have taken certain steps in our organizational structure, financial reporting and contractual relationships to reflect the separateness of us and our general partner from the entities that control our general partner, our credit ratings and business risk profile could be adversely affected if the ratings and risk profiles of EPCO or the entities that control our general partner were viewed as substantially lower or more risky than ours.

The interruption of distributions to us from our subsidiaries and joint ventures may affect our ability to satisfy our obligations and to make distributions to our partners.

We are a partnership holding company with no business operations and our operating subsidiaries conduct all of our operations and own all of our operating assets. Our only significant assets are the ownership interests we own in our subsidiaries and joint ventures. As a result, we depend upon the earnings and cash flow of our subsidiaries and joint ventures and the distribution of that cash to us in order to meet our obligations and to allow us to make distributions to our partners. The ability of our subsidiaries and joint ventures to make distributions to us may be restricted by, among other things, the provisions of existing and future indebtedness, applicable state partnership and limited liability company laws and other laws and regulations, including FERC policies. For example, all cash flows from Evangeline are currently used to service its debt.

In addition, the charter documents governing our joint ventures typically allow their respective joint venture management committees sole discretion regarding the occurrence and amount of distributions. Some of the joint ventures in which we participate have separate credit agreements that contain various restrictive covenants. Among other things, those covenants may limit or restrict the joint venture's ability to make distributions to us under certain circumstances. Accordingly, our joint ventures may be unable to make distributions to us at current levels if at all.

We may be unable to cause our joint ventures to take or not to take certain actions unless some or all of our joint venture participants agree.

We participate in several joint ventures. Due to the nature of some of these arrangements, each participant in these joint ventures has made substantial investments in the joint venture and, accordingly, has required that the relevant charter documents contain certain features designed to provide each participant with the opportunity to participate in the management of the joint venture and to protect its investment, as well as any other assets which may be substantially dependent on or otherwise affected by the activities of that joint venture. These participation and protective features customarily include a corporate governance structure that requires at least a majority-in-interest vote to authorize many basic activities and requires a greater voting interest (sometimes up to 100%) to authorize more significant activities. Examples of these more significant activities are large expenditures or contractual commitments, the construction or acquisition of assets, borrowing money or otherwise raising capital, transactions with affiliates of a joint venture participant, litigation and transactions not in the ordinary course of business, among others. Thus, without the concurrence of joint venture participants with enough voting interests, we may be unable to cause any of our joint ventures to take or not to take certain actions, even though those actions may be in the best interest of us or the particular joint venture.

Moreover, any joint venture owner may sell, transfer or otherwise modify its ownership interest in a joint venture, whether in a transaction involving third parties or the other joint venture owners. Any such transaction could result in us being required to partner with different or additional parties.

A natural disaster, catastrophe or other event could result in severe personal injury, property damage and environmental damage, which could curtail our operations and otherwise materially adversely affect our cash flow and, accordingly, affect the market price of our common units.

Some of our operations involve risks of personal injury, property damage and environmental damage, which could curtail our operations and otherwise materially adversely affect our cash flow. For example, natural gas facilities operate at high pressures, sometimes in excess of 1,100 pounds per square inch. We also operate oil and natural gas facilities located underwater in the Gulf of Mexico, which can involve complexities, such as extreme water pressure. Virtually all of our operations are exposed to potential natural disasters, including hurricanes, tornadoes, storms, floods and/or earthquakes. The location of our assets and our customers' assets in the U.S. Gulf Coast region makes them particularly vulnerable to hurricane risk.

If one or more facilities that are owned by us or that deliver oil, natural gas or other products to us are damaged by severe weather or any other disaster, accident, catastrophe or event, our operations could be significantly interrupted. Similar interruptions could result from damage to production or other facilities that supply our facilities or other stoppages arising from factors beyond our control. These interruptions might involve significant damage to people, property or the environment, and repairs might take from a week or less for a minor incident to six months or more for a major interruption. Additionally, some of the storage contracts that we are a party to obligate us to indemnify our customers for any damage or injury occurring during the period in which the customers' natural gas is in our possession. Any event that interrupts the revenues generated by our operations, or which causes us to make significant expenditures not covered by insurance, could reduce our cash available for paying distributions and, accordingly, adversely affect the market price of our common units.

We believe that EPCO maintains adequate insurance coverage on behalf of us, although insurance will not cover many types of interruptions that might occur and will not cover amounts up to applicable deductibles. As a result of market conditions, premiums and deductibles for certain insurance policies can increase substantially, and in some instances, certain insurance may become unavailable or available only for reduced amounts of coverage. For example, change in the insurance markets subsequent to the terrorist attacks on September 11, 2001 and the hurricanes in 2005 have made it more difficult for us to obtain certain types of coverage. As a result, EPCO may not be able to renew existing insurance policies on behalf of us or procure other desirable insurance on commercially reasonable terms, if at all. If we were to incur a significant liability for which we were not fully insured, it could have a material adverse effect on our financial position and results of operations. In addition, the proceeds of any such insurance may not be paid in a timely manner and may be insufficient if such an event were to occur.

An impairment of goodwill and intangible assets could reduce our earnings.

At December 31, 2007, our balance sheet reflected $591.7 million of goodwill and $917.0 million of intangible assets. Goodwill is recorded when the purchase price of a business exceeds the fair market value of the tangible and separately measurable intangible net assets. Generally accepted accounting principles in the United States ("GAAP") require us to test goodwill for impairment on an annual basis or when events or circumstances occur indicating that goodwill might be impaired. Long-lived assets such as intangible assets with finite useful lives are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. If we determine that any of our goodwill or intangible assets were impaired, we would be required to take an immediate charge to earnings with a correlative effect on partners' equity and balance sheet leverage as measured by debt to total capitalization.

Increases in interest rates could materially adversely affect our business, results of operations, cash flows and financial condition.

In addition to our exposure to commodity prices, we have significant exposure to increases in interest rates. As of December 31, 2007, we had approximately $6.90 billion of consolidated debt, of which approximately $5.03 billion was at fixed interest rates and approximately $1.87 billion was at variable interest rates, after giving effect to existing interest swap arrangements. From time to time, we may enter into additional interest rate swap arrangements, which could increase our exposure to variable interest rates. As a result, our results of operations, cash flows and financial condition, could be materially adversely affected by significant increases in interest rates.

An increase in interest rates may also cause a corresponding decline in demand for equity investments, in general, and in particular for yield-based equity investments such as our common units. Any such reduction in demand for our common units resulting from other more attractive investment opportunities may cause the trading price of our common units to decline.

The use of derivative financial instruments could result in material financial losses by us.

We historically have sought to limit a portion of the adverse effects resulting from changes in oil and natural gas commodity prices and interest rates by using financial derivative instruments and other hedging mechanisms from time to time. To the extent that we hedge our commodity price and interest rate exposures, we will forego the benefits we would otherwise experience if commodity prices or interest rates were to change in our favor. In addition, even though monitored by management, hedging activities can result in losses. Such losses could occur under various circumstances, including if a counterparty does not perform its obligations under the hedge arrangement, the hedge is imperfect, or hedging policies and procedures are not followed.

Our pipeline integrity program may impose significant costs and liabilities on us.

The U.S. Department of Transportation issued final rules (effective March 2001 with respect to hazardous liquid pipelines and February 2004 with respect to natural gas pipelines) requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the rules refer to as "high consequence areas." The final rule resulted from the enactment of the Pipeline Safety Improvement Act of 2002. At this time, we cannot predict the ultimate costs of compliance with this rule because those costs will depend on the number and extent of any repairs found to be necessary as a result of the pipeline integrity testing that is required by the rule. We will continue our pipeline integrity testing programs to assess and maintain the integrity of our pipelines. The results of these tests could cause us to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our pipelines.

Environmental costs and liabilities and changing environmental regulation could materially affect our results of operations, cash flows and financial condition.

Our operations are subject to extensive federal, state and local regulatory requirements relating to environmental affairs, health and safety, waste management and chemical and petroleum products. Governmental authorities have the power to enforce compliance with applicable regulations and permits and to subject violators to civil and criminal penalties, including substantial fines, injunctions or both. Certain environmental laws, including CERCLA and analogous state laws and regulations, impose strict, joint and several liability for costs required to cleanup and restore sites where hazardous substances or hydrocarbons have been disposed or otherwise released. Moreover, third parties, including neighboring landowners, may also have the right to pursue legal actions to enforce compliance or to recover for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment.

We will make expenditures in connection with environmental matters as part of normal capital expenditure programs. However, future environmental law developments, such as stricter laws, regulations, permits or enforcement policies, could significantly increase some costs of our operations, including the handling, manufacture, use, emission or disposal of substances and wastes.

Federal, state or local regulatory measures could materially adversely affect our business, results of operations, cash flows and financial condition.

The FERC regulates our interstate natural gas pipelines and natural gas storage facilities under the Natural Gas Act, and interstate NGL and petrochemical pipelines under the ICA. The STB regulates our interstate propylene pipelines. State regulatory agencies regulate our intrastate natural gas and NGL pipelines, intrastate storage facilities and gathering lines.

Under the Natural Gas Act, the FERC has authority to regulate natural gas companies that provide natural gas pipeline transportation services in interstate commerce. Its authority to regulate those services is comprehensive and includes the rates charged for the services, terms and condition of service and certification and construction of new facilities. The FERC requires that our services are provided on a non-discriminatory basis so that all shippers have open access to our pipelines and storage. Pursuant to the FERC’s jurisdiction over interstate gas pipeline rates, existing pipeline rates may be challenged by customer complaint or by the FERC Staff and proposed rate increases may be challenged by protest.

We have interests in natural gas pipeline facilities offshore from Texas and Louisiana. These facilities are subject to regulation by the FERC and other federal agencies, including the Department of Interior, under the Outer Continental Shelf Lands Act, and by the Department of Transportation’s Office of Pipeline Safety under the Natural Gas Pipeline Safety Act.

Our intrastate NGL and natural gas pipelines are subject to regulation in many states, including Alabama, Colorado, Louisiana, Mississippi, New Mexico and Texas, and by the FERC pursuant to Section 311 of the Natural Gas Policy Act. We also have natural gas underground storage facilities in Louisiana, Mississippi and Texas. Although state regulation is typically less onerous than at the FERC, proposed and existing rates subject to state regulation and the provision of services on a non-discriminatory basis are also subject to challenge by protest and complaint, respectively.

For a general overview of federal, state and local regulation applicable to our assets, see Item 1 of this annual report. This regulatory oversight can affect certain aspects of our business and the market for our products and could materially adversely affect our cash flows.

We are subject to strict regulations at many of our facilities regarding employee safety, and failure to comply with these regulations could adversely affect our ability to make distributions to you.

The workplaces associated with our facilities are subject to the requirements of the federal Occupational Safety and Health Act, or OSHA, and comparable state statutes that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that we maintain information about hazardous materials used or produced in our operations and that we provide this information to employees, state and local governmental authorities and local residents. The failure to comply with OSHA requirements or general industry standards, keep adequate records or monitor occupational exposure to regulated substances could have a material adverse effect on our business, financial condition, results of operations and ability to make distributions to you.

Terrorist attacks aimed at our facilities could adversely affect our business, results of operations, cash flows and financial condition.

Since the September 11, 2001 terrorist attacks on the United States, the United States government has issued warnings that energy assets, including our nation's pipeline infrastructure, may be the future target of terrorist organizations. Any terrorist attack on our facilities or pipelines or those of our customers could have a material adverse effect on our business.

We depend on the leadership and involvement of Dan L. Duncan and other key personnel for the success of our businesses.

We depend on the leadership, involvement and services of Dan L. Duncan, the founder of EPCO and the chairman of our general partner and other key personnel. Mr. Duncan has been integral to our success and the success of EPCO due in part to his ability to identify and develop business opportunities, make strategic decisions and attract and retain key personnel. The loss of his leadership and involvement or the services of certain key members of our senior management team could have a material adverse effect on our business, results of operations, cash flows, market price of our securities and financial condition.

EPCO's employees may be subjected to conflicts in managing our business and the allocation of time and compensation costs between our business and the business of EPCO and its other affiliates.

We have no officers or employees and rely solely on officers of our general partner and employees of EPCO. Certain of our officers are also officers of EPCO and other affiliates of EPCO. These relationships may create conflicts of interest regarding corporate opportunities and other matters, and the resolution of any such conflicts may not always be in our or our unitholders' best interests. In addition, these overlapping officers allocate their time among us, EPCO and other affiliates of EPCO. These officers face potential conflicts regarding the allocation of their time, which may adversely affect our business, results of operations and financial condition.

We have entered into an administrative services agreement that governs business opportunities among entities controlled by EPCO, which includes us and our general partner, Enterprise GP Holdings and its general partner, Duncan Energy Partners and its general partner and TEPPCO and its general partner.

For information regarding how business opportunities are handled within the EPCO group of companies, please read Item 13 of this annual report.

We do not have an independent compensation committee, and aspects of the compensation of our executive officers and other key employees, including base salary, are not reviewed or approved by our independent directors. The determination of executive officer and key employee compensation could involve conflicts of interest resulting in economically unfavorable arrangements for us.

Risks Relating to Our Partnership Structure

We may issue additional securities without the approval of our common unitholders.

At any time, we may issue an unlimited number of limited partner interests of any type (to parties other than our affiliates) without the approval of our unitholders. Our partnership agreement does not give our common unitholders the right to approve the issuance of equity securities including equity securities ranking senior to our common units. The issuance of additional common units or other equity securities of equal or senior rank will have the following effects:

- the ownership interest of a unitholder immediately prior to the issuance will decrease;
- the amount of cash available for distributions on each common unit may decrease;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding common unit may be diminished; and
- the market price of our common units may decline.

We may not have sufficient cash from operations to pay distributions at the current level following establishment of cash reserves and payments of fees and expenses, including payments to EPGP.

Because distributions on our common units are dependent on the amount of cash we generate, distributions may fluctuate based on our performance. We cannot guarantee that we will continue to pay distributions at the current level each quarter. The actual amount of cash that is available to be distributed each quarter will depend upon numerous factors, some of which are beyond our control and the control of EPGP. These factors include but are not limited to the following:

- the level of our operating costs;
- the level of competition in our business segments;
- prevailing economic conditions;
- the level of capital expenditures we make;
- the restrictions contained in our debt agreements and our debt service requirements;
- fluctuations in our working capital needs;
- the cost of acquisitions, if any; and
- the amount, if any, of cash reserves established by EPGP in its sole discretion.

In addition, you should be aware that the amount of cash we have available for distribution depends primarily on our cash flow, including cash flow from financial reserves and working capital borrowings, not solely on profitability, which is affected by non-cash items. As a result, we may make cash distributions during periods when we record losses and we may not make distributions during periods when we record net income.

We do not have the same flexibility as other types of organizations to accumulate cash and equity to protect against illiquidity in the future.

Unlike a corporation, our partnership agreement requires us to make quarterly distributions to our unitholders of all available cash reduced by any amounts of reserves for commitments and contingencies, including capital and operating costs and debt service requirements. The value of our units and other limited partner interests may decrease in correlation with decreases in the amount we distribute per unit. Accordingly, if we experience a liquidity problem in the future, we may not be able to issue more equity to recapitalize.

Cost reimbursements and fees due to EPCO and its affiliates, including our general partner may be substantial and will reduce our cash available for distribution to holders of our units.

Prior to making any distribution on our units, we will reimburse EPCO and its affiliates, including officers and directors of EPGP, for all expenses they incur on our behalf, including allocated overhead. These amounts will include all costs incurred in managing and operating us, including costs for rendering administrative staff and support services to us, and overhead allocated to us by EPCO. The payment of these amounts could adversely affect our ability to pay cash distributions to holders of our units. EPCO has sole discretion to determine the amount of these expenses. In addition, EPCO and its affiliates may provide other services to us for which we will be charged fees as determined by EPCO.

EPGP and its affiliates have limited fiduciary responsibilities to, and conflicts of interest with respect to, our partnership, which may permit it to favor its own interests to your detriment.

The directors and officers of EPGP and its affiliates have duties to manage EPGP in a manner that is beneficial to its members. At the same time, EPGP has duties to manage our partnership in a manner that is beneficial to us. Therefore, EPGP's duties to us may conflict with the duties of its officers and directors to its members. Such conflicts may include, among others, the following:

- neither our partnership agreement nor any other agreement requires EPGP or EPCO to pursue a business strategy that favors us;
- decisions of EPGP regarding the amount and timing of asset purchases and sales, cash expenditures, borrowings, issuances of additional units and reserves in any quarter may affect the level of cash available to pay quarterly distributions to unitholders and EPGP;
- under our partnership agreement, EPGP determines which costs incurred by it and its affiliates are reimbursable by us;
- EPGP is allowed to resolve any conflicts of interest involving us and EPGP and its affiliates;
- EPGP is allowed to take into account the interests of parties other than us, such as EPCO, in resolving conflicts of interest, which has the effect of limiting its fiduciary duty to unitholders;
- any resolution of a conflict of interest by EPGP not made in bad faith and that is fair and reasonable to us shall be binding on the partners and shall not be a breach of our partnership agreement;
- affiliates of EPGP, including TEPPCO, may compete with us in certain circumstances;
- EPGP has limited its liability and reduced its fiduciary duties and has also restricted the remedies available to our unitholders for actions that might, without the limitations, constitute breaches of fiduciary duty. As a result of purchasing our units, you are deemed to consent to some actions and

conflicts of interest that might otherwise constitute a breach of fiduciary or other duties under applicable law;

- we do not have any employees and we rely solely on employees of EPCO and its affiliates;
- in some instances, EPGP may cause us to borrow funds in order to permit the payment of distributions, even if the purpose or effect of the borrowing is to make incentive distributions;
- our partnership agreement does not restrict EPGP from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf;
- EPGP intends to limit its liability regarding our contractual and other obligations and, in some circumstances, may be entitled to be indemnified by us;
- EPGP controls the enforcement of obligations owed to us by our general partner and its affiliates; and
- EPGP decides whether to retain separate counsel, accountants or others to perform services for us.

We have significant business relationships with entities controlled by Dan L. Duncan, including EPCO and TEPPCO. For detailed information on these relationships and related transactions with these entities, see Item 13 included within this annual report.

Unitholders have limited voting rights and are not entitled to elect our general partner or its directors, which could lower the trading price of our common units. In addition, even if unitholders are dissatisfied, they cannot easily remove our general partner.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Unitholders did not elect EPGP or its directors and will have no right to elect our general partner or its directors on an annual or other continuing basis. The board of directors of our general partner, including the independent directors, is chosen by the owners of the general partner and not by the unitholders.

Furthermore, if unitholders are dissatisfied with the performance of our general partner, they currently have no practical ability to remove EPGP or its officers or directors. EPGP may not be removed except upon the vote of the holders of at least 60% of our outstanding units voting together as a single class. Because affiliates of EPGP currently own approximately 34.0% of our outstanding common units, the removal of EPGP as our general partner is highly unlikely without the consent of both EPGP and its affiliates. As a result of this provision, the trading price of our common units may be lower than other forms of equity ownership because of the absence or reduction of a takeover premium in the trading price.

Our partnership agreement restricts the voting rights of unitholders owning 20% or more of our common units.

Unitholders' voting rights are further restricted by a provision in our partnership agreement stating that any units held by a person that owns 20% or more of any class of our common units then outstanding, other than our general partner and its affiliates, cannot be voted on any matter. In addition, our partnership agreement contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting our unitholders' ability to influence the manner or direction of our management. As a result of this provision, the trading price of our common units may be lower than other forms of equity ownership because of the absence or reduction of a takeover premium in the trading price.

EPGP has a limited call right that may require common unitholders to sell their units at an undesirable time or price.

If at any time EPGP and its affiliates own 85% or more of the common units then outstanding, EPGP will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the remaining common units held by unaffiliated persons at a price not less than the then current market price. As a result, common unitholders may be required to sell their common units at an undesirable time or price and may therefore not receive any return on their investment. They may also incur a tax liability upon a sale of their units.

Our common unitholders may not have limited liability if a court finds that limited partner actions constitute control of our business.

Under Delaware law, common unitholders could be held liable for our obligations to the same extent as a general partner if a court determined that the right of limited partners to remove our general partner or to take other action under our partnership agreement constituted participation in the "control" of our business.

Under Delaware law, our general partner generally has unlimited liability for our obligations, such as our debts and environmental liabilities, except for those of our contractual obligations that are expressly made without recourse to our general partner.

The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the states in which we do business. You could have unlimited liability for our obligations if a court or government agency determined that:

- we were conducting business in a state, but had not complied with that particular state’s partnership statute; or
- your right to act with other unitholders to remove or replace our general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constituted "control" of our business.

Unitholders may have liability to repay distributions.

Under certain circumstances, our unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act (the "Delaware Act"), we may not make a distribution to our unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Liabilities to partners on account of their partnership interests and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted. Delaware law provides that for a period of three years from the date of an impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. A purchaser of common units who becomes a limited partner is liable for the obligations of the transferring limited partner to make contributions to the partnership that are known to such purchaser of common units at the time it became a limited partner and for unknown obligations if the liabilities could be determined from our partnership agreement.

Sales of a large number of our outstanding common units in the market may depress the market price of our common units.

Sales of a substantial number of our common units in the public market could cause the market price of our common units to decline. As of February 1, 2008, we had 435,241,826 common units outstanding. Sales of a substantial number of these common units in the trading markets, whether in a single transaction or series of transactions, or the possibility that these sales may occur, could reduce the market price of our outstanding common units. In addition, these sales, or the possibility that these sales may occur, could make it more difficult for us to sell our common units in the future.

Our general partner's interest in us and the control of our general partner may be transferred to a third party without unitholder consent.

After June 30, 2008, our general partner, in accordance with our partnership agreement, may transfer its general partner interest without the consent of unitholders. In addition, our general partner may transfer its general partner interest to a third party in a merger or consolidation or in a sale of all or substantially all of its assets without the consent of our unitholders. Furthermore, there is no restriction in our partnership agreement on the ability of Enterprise GP Holdings or its affiliates to transfer their equity interests in our general partner to a third party. The new equity owner of our general partner would then be in a position to replace the board of directors and officers of our general partner with their own choices and to influence the decisions taken by the board of directors and officers of our general partner.

Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the IRS were to treat us as a corporation or if we were to become subject to a material amount of entity-level taxation for state tax purposes, then our cash available for distribution to our common unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the Internal Revenue Service ("IRS") on this matter.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35%. Distributions to our unitholders would generally be taxed again as corporate distributions, and no income, gains, losses or deductions would flow through to our unitholders. Because a tax would be imposed upon us as a corporation, the cash available for distributions to our common unitholders would be substantially reduced. Thus, treatment of us as a corporation would result in a material reduction in the after-tax return to our common unitholders, likely causing a substantial reduction in the value of our common units.

Current law may change, causing us to be treated as a corporation for federal income tax purposes or otherwise subjecting us to a material amount of entity level taxation. In addition, because of widespread state budget deficits and other reasons, several states (including Texas) are evaluating ways to enhance state-tax collections. For example, with respect to tax reports due on or after January 1, 2008, our operating subsidiaries are subject to the Revised Texas Franchise Tax on that portion of their revenue generated in Texas. Specifically, the Revised Texas Franchise Tax is imposed at a maximum effective rate of 0.7% of the operating subsidiaries' gross revenue that is apportioned to Texas. If any additional state were to impose an entity-level tax upon us or our operating subsidiaries, the cash available for distribution to our common unitholders would be reduced.

The tax treatment of publicly traded partnerships or an investment in our common units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial interpretation at any time. Any modification to the U.S. federal income tax laws and interpretations thereof could make it more difficult or impossible to meet the exception for us to be treated as a partnership for U.S. federal income tax purposes that is not taxable as a corporation, or Qualifying Income Exception, affect or cause us to change our business activities, affect the tax considerations of an investment in us, change the character or treatment of portions of our income and adversely affect an investment in our common units. For example, in response to certain recent developments, members of Congress are considering substantive changes to the definition of qualifying income under Section 7704(d) of the Internal Revenue Code. It is possible that these legislative efforts could result in changes to the existing U.S. tax laws that affect publicly traded partnerships, including us. Modifications to the U.S. federal income tax laws and interpretations thereof may or may not be applied retroactively. We are unable to predict whether any changes will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular common unit is transferred.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury regulations, and, accordingly, our counsel is unable to opine as to the validity of this method. If the IRS were to successfully challenge this method or new Treasury regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A successful IRS contest of the federal income tax positions we take may adversely impact the market for our common units, and the costs of any contests will be borne by our unitholders and our general partner.

The IRS may adopt positions that differ from the positions we take, even positions taken with advice of counsel. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with some or all of the positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which our common units trade. In addition, the costs of any contest with the IRS, principally legal, accounting and related fees, will be borne indirectly by our unitholders and our general partner.

Even if our common unitholders do not receive any cash distributions from us, they will be required to pay taxes on their share of our taxable income.

Common unitholders will be required to pay federal income taxes and, in some cases, state and local income taxes on their share of our taxable income whether or not they receive any cash distributions from us. Our common unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability which results from their share of our taxable income.

Tax gain or loss on the disposition of our common units could be different than expected.

If a common unitholder sells its common units, the unitholder will recognize a gain or loss equal to the difference between the amount realized and the unitholder's tax basis in those common units. Prior distributions to a unitholder in excess of the total net taxable income a unitholder is allocated for a common unit, which decreased the unitholder's tax basis in that common unit, will, in effect, become taxable income to the unitholder if the common unit is sold at a price greater than the unitholder's tax basis in that common unit, even if the price the unitholder receives is less than the unitholder's original cost. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income to a unitholder.

Tax-exempt entities and non-U.S. persons face unique tax issues from owning common units that may result in adverse tax consequences to them.

Investments in common units by tax-exempt entities, such as individual retirement accounts (known as IRAs), other retirement plans and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to unitholders who are organizations exempt from federal income tax, including individual retirement accounts and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file United States federal income tax returns and pay tax on their share of our taxable income.

We will treat each purchaser of our common units as having the same tax benefits without regard to the units purchased. The IRS may challenge this treatment, which could adversely affect the value of our common units.

Because we cannot match transferors and transferees of common units, we adopt depreciation and amortization positions that may not conform with all aspects of applicable Treasury regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to a common unitholder. It also could affect the timing of these tax benefits or the amount of gain from a sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to the common unitholder's tax returns.

Our common unitholders will likely be subject to state and local taxes and return filing requirements in states where they do not live as a result of an investment in our common units.

In addition to federal income taxes, our common unitholders will likely be subject to other taxes, including state and local income taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property. Our common unitholders will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, they may be subject to penalties for failure to comply with those requirements. We may own property or conduct business in other states or foreign countries in the future. It is the responsibility of the common unitholder to file all federal, state and local tax returns.

The sale or exchange of 50% or more of our capital and profits interests during any twelve-month period will result in the termination of our partnership for federal income tax purposes.

We will be considered to have terminated for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. Our termination would, among other things, result in the closing of our taxable year for all unitholders and could result in a deferral of depreciation deductions allowable in computing our taxable income.

We have adopted certain valuation methodologies that may result in a shift of income, gain, loss and deduction between EPGP and our unitholders. The IRS may challenge this treatment, which could adversely affect the value of our common units.

When we issue additional common units or engage in certain other transactions, we determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and EPGP. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and EPGP, which may be unfavorable to such unitholders. Moreover, subsequent purchasers of common units may have a greater portion of their Internal Revenue code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our methods, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between EPGP and certain of our unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from a unitholder's sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to the unitholder's tax returns.

Item 1B. ***Unresolved Staff Comments*.**

None.

Item 3. ***Legal Proceedings*.**

On occasion, we or our unconsolidated affiliates are named as defendants in litigation relating to our normal business activities, including regulatory and environmental matters. Although we are insured against various business risks to the extent we believe it is prudent, there is no assurance that the nature and amount of such insurance will be adequate, in every case, to indemnify us against liabilities arising from future legal proceedings as a result of our ordinary business activities. We are unaware of any significant litigation, pending or threatened, that could have a significant adverse effect on our financial position, cash flows or results of operations. For detailed information regarding our legal proceedings, see Note 20 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Item 4. ***Submission of Matters to a Vote of Security Holders*.**

There were no matters voted on by our unitholders during the fourth quarter of 2007. On January 29, 2008, we held a special meeting where our unitholders where asked to approve the terms of the Enterprise Products 2008 Long-Term Incentive Plan (the "Enterprise Products 2008 LTIP"), which provides for awards of (i) options to purchase our common units, (ii) restricted units, (iii) phantom units, (iv) distribution equivalent rights and (v) common unit appreciation rights. These awards would be available for grant to employees and consultants of EPCO, including those who provide services on our behalf, and non-employee directors of our general partner. The Enterprise Products 2008 LTIP provides for the issuance of up to 10,000,000 of our common units as awards to such individuals. The following is a summary of the votes cast by our unitholders, which approved the terms of the Enterprise Products 2008 LTIP.

	Number of Votes Cast
For	243,283,982
Against	13,383,667
Abstentions	2,236,957

PART II

Item 5. *Market for Registrant's Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities.*

Market Information and Cash Distributions

Our common units are listed on the NYSE under the ticker symbol "EPD." As of February 1, 2008, there were approximately 904 unitholders of record of our common units. The following table presents the high and low sales prices for our common units during the periods indicated (as reported by the NYSE Composite Transaction Tape) and the amount, record date and payment date of the quarterly cash distributions we paid on each of our common units.

	Price Ranges		Cash Distribution History		
	High	Low	Per Unit	Record Date	Payment Date
2006					
1st Quarter	$26.000	$23.690	$0.4450	Apr. 28, 2006	May 10, 2006
2nd Quarter	$25.710	$23.760	$0.4525	Jul. 31, 2006	Aug. 10, 2006
3rd Quarter	$27.060	$25.000	$0.4600	Oct. 31, 2006	Nov. 8, 2006
4th Quarter	$29.980	$26.050	$0.4675	Jan. 31, 2007	Feb. 8, 2007
2007					
1st Quarter	$32.750	$28.060	$0.4750	Apr. 30, 2007	May 10, 2007
2nd Quarter	$33.350	$30.220	$0.4825	Jul. 31, 2007	Aug. 9, 2007
3rd Quarter	$33.700	$26.136	$0.4900	Oct. 31, 2007	Nov. 8, 2007
4th Quarter	$32.450	$29.920	$0.5000	Jan. 31, 2008	Feb. 7, 2008

The quarterly cash distributions shown in the table above correspond to cash flows for the quarters indicated. The actual cash distributions (i.e., the payments made to our partners) occur within 45 days after the end of such quarter. We expect to fund our quarterly cash distributions to partners primarily with cash provided by operating activities. For additional information regarding our cash flows from operating activities, see "Liquidity and Capital Resources" included under Item 7 of this annual report. Although the payment of cash distributions is not guaranteed, we expect to continue to pay comparable cash distributions in the future.

Recent Sales of Unregistered Securities

There were no sales of unregistered equity securities during 2007.

Common Units Authorized for Issuance Under Equity Compensation Plan

See "Securities Authorized for Issuance Under Equity Compensation Plans" under Item 12 of this annual report, which is incorporated by reference into this Item 5.

Issuer Purchases of Equity Securities

We have not repurchased any of our common units since 2002. In December 1998, we announced a common unit repurchase program whereby we, together with certain affiliates, intended to repurchase up to 2,000,000 of our common units for the purpose of granting options to management and key employees (amount adjusted for the 2-for-1 unit split in May 2002). As of February 1, 2008, we and our affiliates could repurchase up to 618,400 additional common units under this repurchase program.

Item 6. ***Selected Financial Data*****.**

The following table presents selected historical consolidated financial data of our partnership. This information has been derived from our audited financial statements and should be read in conjunction with the audited financial statements included under Item 8 of this annual report. In addition, information regarding our results of operations and liquidity and capital resources can be found under Item 7 of this annual report. As presented in the table, amounts are in thousands (except per unit data).

	For the Year Ended December 31,				
	2007	2006	2005	2004	2003
Operating results data: (1)					
Revenues	$16,950,125	$13,990,969	$12,256,959	$8,321,202	$5,346,431
Income from continuing operations (2)	$ 533,674	$ 599,683	$ 423,716	$ 257,480	$ 104,546
Income per unit from continuing operations:					
Basic	$ 0.96	$ 1.22	$ 0.92	$ 0.83	$ 0.42
Diluted	$ 0.96	$ 1.22	$ 0.92	$ 0.83	$ 0.41
Other financial data:					
Distributions per common unit (3)	$ 1.9475	$ 1.825	$ 1.698	$ 1.540	$ 1.470

	As of December 31,				
	2007	2006	2005	2004	2003
Financial position data: (1)					
Total assets	$16,608,007	$13,989,718	$12,591,016	$11,315,461	$4,802,814
Long-term and current maturities of debt (4)	$ 6,906,145	$ 5,295,590	$ 4,833,781	$ 4,281,236	$2,139,548
Partners' equity (5)	$ 6,131,649	$ 6,480,233	$ 5,679,309	$ 5,328,785	$1,705,953
Total units outstanding (excluding treasury) (5)	435,297	432,408	389,861	364,786	217,780

(1) In general, our historical operating results and financial position have been affected by numerous acquisitions since 2002. Our most significant transaction to date was the GulfTerra Merger, which was completed on September 30, 2004. The aggregate value of the total consideration we paid or issued to complete the GulfTerra Merger was approximately $4 billion. We accounted for the GulfTerra Merger and our other acquisitions using purchase accounting; therefore, the operating results of these acquired entities are included in our financial results prospectively from their respective acquisition dates.

(2) Amounts presented for the years ended December 31, 2006, 2005 and 2004 are before the cumulative effect of accounting changes.

(3) Distributions per common unit represent declared cash distributions with respect to the four fiscal quarters of each period presented.

(4) In general, the balances of our long-term and current maturities of debt have increased over time as a result of financing all or a portion of acquisitions and other capital spending.

(5) We regularly issue common units through underwritten public offerings and, less frequently, in connection with acquisitions or other transactions. The increase in partners' equity since 2003 has been the result of such transactions, with the September 2004 issuance of 104.5 million common units in connection with the GulfTerra Merger being our largest. For additional information regarding our partners' equity and unit history, see Note 15 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Item 7. ***Management's Discussion and Analysis of Financial Condition and Results of Operations.***

For the years ended December 31, 2007, 2006 and 2005.

The following information should be read in conjunction with our consolidated financial statements and our accompanying notes included under Item 8 of this annual report. Our discussion and analysis includes the following:

- Cautionary Note Regarding Forward-Looking Statements.
- Significant Relationships Referenced in this Discussion and Analysis.
- Overview of Business.
- Recent Developments – Discusses significant developments during the year ended December 31, 2007.
- Results of Operations – Discusses material year-to-year variances in our Statements of Consolidated Operations.
- Liquidity and Capital Resources – Addresses available sources of liquidity and capital resources and includes a discussion of our capital spending program.
- Critical Accounting Policies and Estimates.
- Other Items – Includes information related to contractual obligations, off-balance sheet arrangements, related party transactions, recent accounting pronouncements and similar disclosures.

As generally used in the energy industry and in this discussion, the identified terms have the following meanings:

/d	= per day
BBtus	= billion British thermal units
Bcf	= billion cubic feet
MBPD	= thousand barrels per day
MMBbls	= million barrels
MMBtus	= million British thermal units
MMcf	= million cubic feet

Our financial statements have been prepared in accordance with U.S generally accepted accounting principles ("GAAP").

Cautionary Note Regarding Forward-Looking Statements

This discussion contains various forward-looking statements and information that are based on our beliefs and those of our general partner, as well as assumptions made by us and information currently available to us. When used in this document, words such as "anticipate," "project," "expect," "plan," "seek," "goal," "forecast," "intend," "could," "should," "will," "believe," "may," "potential" and similar expressions and statements regarding our plans and objectives for future operations, are intended to identify forward-looking statements. Although we and our general partner believe that such expectations reflected in such forward-looking statements are reasonable, neither we nor our general partner can give any assurances that such expectations will prove to be correct. Such statements are subject to a variety of risks, uncertainties and assumptions as described in more detail in Item 1A of this annual report. If one or more of these risks or uncertainties materialize, or if underlying assumptions

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prove incorrect, our actual results may vary materially from those anticipated, estimated, projected or expected. You should not put undue reliance on any forward-looking statements.

Significant Relationships Referenced in this Discussion and Analysis

Unless the context requires otherwise, references to "we," "us," "our," or "Enterprise Products Partners" are intended to mean the business and operations of Enterprise Products Partners L.P. and its consolidated subsidiaries.

References to "EPO" mean Enterprise Products Operating LLC as successor in interest by merger to Enterprise Products Operating L.P., which is a wholly owned subsidiary of Enterprise Products Partners through which Enterprise Products Partners conducts substantially all of its business.

References to "Duncan Energy Partners" mean Duncan Energy Partners L.P., which is a consolidated subsidiary of EPO. Duncan Energy Partners is a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol "DEP." References to "DEP GP" mean DEP Holdings, LLC, which is the general partner of Duncan Energy Partners and is wholly owned by EPO.

References to "EPGP" mean Enterprise Products GP, LLC, which is our general partner.

References to "Enterprise GP Holdings" mean Enterprise GP Holdings L.P., a publicly traded affiliate, the units of which are listed on the NYSE under the ticker symbol "EPE." Enterprise GP Holdings owns Enterprise Products GP. References to "EPE Holdings" mean EPE Holdings, LLC, which is the general partner of Enterprise GP Holdings.

References to "TEPPCO" mean TEPPCO Partners, L.P., a publicly traded affiliate, the common units of which are listed on the NYSE under the ticker symbol "TPP." References to "TEPPCO GP" refer to Texas Eastern Products Pipeline Company, LLC, which is the general partner of TEPPCO and is wholly owned by Enterprise GP Holdings.

References to "Energy Transfer Equity" mean the business and operations of Energy Transfer Equity, L.P. and its consolidated subsidiaries, which include Energy Transfer Partners, L.P. ("ETP"). Energy Transfer Equity is a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol "ETE." The general partner of Energy Transfer Equity is LE GP, LLC ("LE GP"). On May 7, 2007, Enterprise GP Holdings acquired non-controlling interests in both LE GP and Energy Transfer Equity.

References to "Employee Partnerships" mean EPE Unit L.P. ("EPE Unit I"), EPE Unit II, L.P. ("EPE Unit II") and EPE Unit III, L.P. ("EPE Unit III"), collectively, which are private company affiliates of EPCO, Inc. See Note 25 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding the formation of Enterprise Unit L.P. in February 2008.

References to "EPCO" mean EPCO, Inc. and its wholly-owned private company affiliates, which are related party affiliates to all of the foregoing named entities.

We, EPO, Duncan Energy Partners, DEP GP, EPGP, Enterprise GP Holdings, EPE Holdings, TEPPCO and TEPPCO GP are affiliates under the common control of Dan L. Duncan, the Group Co-Chairman and controlling shareholder of EPCO.

Overview of Business

We are a North American midstream energy company providing a wide range of services to producers and consumers of natural gas, natural gas liquids ("NGLs"), and crude oil, and certain petrochemicals. In addition, we are an industry leader in the development of pipeline and other midstream energy infrastructure in the continental United States and Gulf of Mexico. We are a publicly traded

Delaware limited partnership formed in 1998, the common units of which are listed on the New York Stock Exchange ("NYSE") under the ticker symbol "EPD."

We conduct substantially all of our business through EPO. We are owned 98% by our limited partners and 2% by our general partner, EPGP. EPGP is owned 100% by Enterprise GP Holdings, a publicly traded affiliate listed on the NYSE under the ticker symbol "EPE." We, EPGP and Enterprise GP Holdings are affiliates and under the common control of Dan L. Duncan, the Chairman and controlling shareholder of EPCO.

Our midstream energy asset network links producers of natural gas, NGLs and crude oil from some of the largest supply basins in the United States, Canada and the Gulf of Mexico with domestic consumers and international markets. We have four reportable business segments: NGL Pipelines & Services; Onshore Natural Gas Pipelines & Services; Offshore Pipelines & Services; and Petrochemical Services. Our business segments are generally organized and managed according to the type of services rendered (or technologies employed) and products produced and/or sold.

Recent Developments

The following information highlights our significant developments since January 1, 2007 through the date of this filing.

Questar Pipeline and Enterprise Products Partners Enter Into Definitive Agreements to Construct New Rockies Natural Gas Pipeline Hub

In February 2008, we entered into definitive agreements with Questar Pipeline Company ("Questar") to develop a new natural gas pipeline hub in the Rockies. As proposed, the White River Hub would be a header system that will be owned equally by us and Questar. The facilities would connect our natural gas processing complex near Meeker, Colorado, with up to six interstate pipelines in the Piceance Basin area, including the Questar Pipeline.

Our Pioneer Cryogenic Natural Gas Processing Facility Commences Operations

In February 2008, we commenced operations at our recently completed Pioneer cryogenic natural gas processing facility. Located near the Opal Hub in southwestern Wyoming, this new facility is designed to process up to 750 MMcf/d of natural gas and extract as much as 30 MBPD of NGLs. We intend to maintain the operational capability of our Pioneer silica gel natural gas processing plant, which is located adjacent to the Pioneer cryogenic plant, as a back-up to provide producers with additional assurance of our processing capability at the complex. NGLs extracted at our Pioneer complex are transported on our Mid-America Pipeline System and ultimately to our Hobbs and Mont Belvieu NGL fractionators.

We and the Jicarilla Apache Nation Announce Plans to Form Joint Venture involving our San Juan Natural Gas Gathering Assets

In November 2007, we and the Jicarilla Apache Nation announced our plans for the formation of a joint venture to own and operate natural gas gathering assets located on or near Jicarilla Apache Nation reservation lands. The joint venture would own and operate gathering assets in northwest New Mexico that were previously 100% owned by us. In order to take effect, the agreements related to the joint venture must be approved by the U.S. Department of the Interior. The Jicarilla Apache Nation is a federally-recognized Indian tribe, whose Reservation was established in 1887 and now consists of approximately 880,000 acres of land located on the eastern edge of the San Juan Basin.

Under the terms of the joint venture agreement, we would receive relatively equivalent value for our contributions of (i) 545 miles of gathering lines, which have an approximate throughput of 31 MMcf/d, (ii) related gathering assets and (iii) 40 MMcf/d of redelivery and natural gas processing capacity through our San Juan Gathering System. The Jicarilla Apache Nation would contribute rights for access and use of reservation lands for operation and expansion of the joint venture gathering system, which will be operated by us. The joint venture assets are currently part of our San Juan Gathering System, which is comprised of approximately 6,065 miles of natural gas pipelines in New Mexico and Colorado that gather more than 1 Bcf/d of natural gas.

EPO Increases and Extends its Multi-Year Revolving Credit Facility

In November 2007, EPO amended its existing Multi-Year Revolving Credit Facility to, among other terms, increase total bank commitments from $1.25 billion to $1.75 billion and extend the maturity date to November 2012. In addition, the amendment provides us with the option to further increase commitments under the credit facility up to a maximum of $2.25 billion upon satisfaction of certain conditions. For additional information regarding this issuance of debt, see Note 14 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Our Meeker Natural Gas Processing Facility Commences Operations

In October 2007, we commenced natural gas processing operations at our Meeker I facility, which recently completed its first phase of construction. Located in Colorado's Piceance Basin, our Meeker I facility has a processing capacity of 750 MMcf/d of natural gas and is capable of extracting up to 35 MBPD of mixed NGLs. The Meeker II facility, which is under construction and expected to be completed in the third quarter of 2008, will double its processing capacity to 1.5 Bcf/d of natural gas and 70 MBPD of mixed NGLs.

The two phases are supported by long-term commitments from producers, including EnCana and ExxonMobil. By the end of 2008, natural gas volumes processed at the facility are expected to exceed 800 MMcf/d, which we believe could yield to us approximately 40 MBPD of equity NGLs in full extraction mode. The Piceance Basin represents one of the most prolific and fastest growing energy producing areas in the nation, and the completion of our Meeker facility provides the region with valuable midstream infrastructure needed to accommodate those growing volumes.

Completion of the Final Phase of our Mid-America Pipeline Expansion Project

In October 2007, we completed the expansion of the Rocky Mountain portion of our Mid-America Pipeline ("MAPL") system. The final phase of this project consisted of installing new pumps and the modification of existing pumps, which increased system capacity by 20 MBPD. The first phase, which was completed in April 2007, provided an additional 30 MBPD of system capacity. Overall, these expansion projects increased the capacity of MAPL's Rocky Mountain system from 225 MBPD to 275 MBPD. This expansion will accommodate expected mixed NGL volumes originating from our Meeker, Pioneer and Chaco facilities.

EPO Issues $800.0 Million of Senior Notes

In September 2007, EPO sold $800.0 million in principal amount of 6.30% fixed-rate, unsecured senior notes due September 2017. Net proceeds from this offering were used to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility. In October 2007, EPO used borrowing capacity under its revolver to repay $500.0 million in principal amount due under its maturing Senior Notes E. For additional information regarding this issuance of debt, see Note 14 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Expansion of our Mont Belvieu Petrochemical Assets Completed

In August 2007, we completed the expansion of our petrochemical assets in Mont Belvieu and southeast Texas. This expansion project included (i) the construction of a fourth propylene fractionator at our Mont Belvieu complex, which increased our propylene/propane fractionation capacity by approximately one billion pounds per year, or 15 MBPD, and (ii) the expansion of two refinery grade propylene pipelines which added 50 MBPD of capacity into Mont Belvieu.

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Completion of our Hobbs NGL Fractionator

In August 2007, we completed construction of our Hobbs NGL fractionator, which is designed to handle up to 75 MBPD of mixed NGLs. The new fractionator is strategically located at the interconnection of our MAPL and our Seminole pipelines near Hobbs, New Mexico. Our Hobbs NGL fractionator offers another key hub for separating mixed NGLs produced at our Meeker, Pioneer and Chaco facilities into purity NGL products.

Changes in our Management Team

In July 2007, we announced changes to our senior management team that became effective August 1, 2007. The board of directors of our general partner elected Michael A. Creel president and chief executive officer, W. Randall Fowler executive vice president and chief financial officer, and William Ordemann executive vice president and chief operating officer. Mr. Creel replaces Robert G. Phillips who resigned effective June 30, 2007. Mr. Fowler was promoted to fill the position left vacant by Mr. Creel's promotion. Mr. Ordemann was promoted to fill the position vacated by Dr. Ralph S. Cunningham, who is now the president and chief executive officer of Enterprise GP Holdings. Mr. Creel had previously held this position.

Our Independence Hub Platform and Trail Pipeline Receive First Production

In July 2007, our Independence Hub platform and Independence Trail pipeline received first production from deepwater production wells connected to the Independence Hub platform. As a result, these assets began earning fee-based revenues for natural gas processing and transportation services. These amounts are in addition to the demand fee revenues that Independence Hub began earning in March 2007. Currently, the platform is receiving approximately 900 MMcf/d of natural gas from fifteen wells.

We and TEPPCO Complete the First Portion of the Jonah Phase V Expansion Project

In July 2007, we completed the first portion of the Phase V Expansion of the Jonah Gathering System, which increased the system gathering capacity to 2.0 Bcf/d. The second and final phase of the expansion, which is targeted for completion in April 2008, is expected to increase the system's gathering capacity further to 2.4 Bcf/d.

Expansion of our Houston Ship Channel NGL Import and Export Terminal Completed

In June 2007, we announced the completion of our project to expand the capabilities of our import/export terminal at the Houston Ship Channel to handle incremental volumes of natural gas liquids and liquefied petroleum gases.

EPO Issues $700.0 Million of Junior Notes

In May 2007, EPO sold $700 million in principal amount of fixed/floating unsecured junior subordinated notes due January 2068. Net proceeds from this offering were used by EPO to temporarily reduce borrowings outstanding under its Multi-Year Revolving Credit Facility and for general partnership purposes. For additional information regarding this issuance of debt, see Note 14 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Creation of our Natural Gas Services and Marketing Business

In March 2007, we announced the expansion of our natural gas services and marketing business similar to our existing NGL and petrochemical marketing businesses. This business will include all of our existing natural gas supply and marketing activities, which currently include producer wellhead services, facility fuel procurement, pipeline and storage capacity optimization and a full range of market customer delivery arrangements. This initiative is expected to broaden our role in the natural gas markets by linking our extensive U.S. natural gas pipeline and storage assets, thus providing customers with value-added solutions and reducing our operating costs through enhanced fuel procurement practices.

Duncan Energy Partners Completes its Initial Public Offering

In February 2007, a consolidated subsidiary of ours, Duncan Energy Partners, completed its underwritten initial public offering of 14,950,000 common units. Duncan Energy Partners, a Delaware limited partnership, was formed by EPO to acquire ownership interests in certain of our midstream energy businesses. EPO owns the 2% general partner interest and 5,351,571 common units of Duncan Energy Partners as well as a direct 34% equity interest in each of Duncan Energy Partners operating subsidiaries. For additional information regarding Duncan Energy Partners, see "Other Items – Initial Public Offering of Duncan Energy Partners" included within this Item 7.

Results of Operations

We have four reportable business segments: NGL Pipelines & Services; Onshore Natural Gas Pipelines & Services; Offshore Pipelines & Services; and Petrochemical Services. Our business segments are generally organized and managed according to the type of services rendered (or technologies employed) and products produced and/or sold.

We evaluate segment performance based on the non-GAAP financial measure of gross operating margin. Gross operating margin (either in total or by individual segment) is an important performance measure of the core profitability of our operations. This measure forms the basis of our internal financial reporting and is used by senior management in deciding how to allocate capital resources among business segments. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating segment results. The GAAP financial measure most directly comparable to total segment gross operating margin is operating income. Our non-GAAP financial measure of total segment gross operating margin should not be considered as an alternative to GAAP operating income.

We define total segment gross operating margin as consolidated operating income before (i) depreciation, amortization and accretion expense; (ii) operating lease expenses for which we do not have the payment obligation; (iii) gains and losses on the sale of assets; and (iv) general and administrative costs. Gross operating margin is exclusive of other income and expense transactions, provision for income taxes, minority interest, extraordinary charges and the cumulative effect of change in accounting principle. Gross operating margin by segment is calculated by subtracting segment operating costs and expenses (net of the adjustments noted above) from segment revenues, with both segment totals before the elimination of intersegment and intrasegment transactions. Intercompany accounts and transactions are eliminated in consolidation.

We include earnings from equity method unconsolidated affiliates in our measurement of segment gross operating margin and operating income. Our equity investments with industry partners are a vital component of our business strategy. They are a means by which we conduct our operations to align our interests with those of our customers and/or suppliers. This method of operation also enables us to achieve favorable economies of scale relative to the level of investment and business risk assumed versus what we could accomplish on a stand-alone basis. Many of these businesses perform supporting or complementary roles to our other business operations. As circumstances dictate, we may increase our ownership interest in equity investments, which could result in their subsequent consolidation into our operations.

Our consolidated gross operating margin amounts include the gross operating margin amounts of Duncan Energy Partners on a 100% basis. Volumetric data associated with the operations of Duncan Energy Partners are also included on a 100% basis in our consolidated statistical data.

For additional information regarding our business segments, see Note 16 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

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Selected Price and Volumetric Data

The following table illustrates selected annual and quarterly industry index prices for natural gas, crude oil and selected NGL and petrochemical products for the periods presented.

	Natural Gas, $/MMBtu	Crude Oil, $/barrel	Ethane, $/gallon	Propane, $/gallon	Normal Butane, $/gallon	Isobutane, $/gallon	Natural Gasoline, $/gallon	Polymer Grade Propylene, $/pound	Refinery Grade Propylene, $/pound
	(1)	(2)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
2005 Averages	$8.64	$56.47	$0.62	$0.91	$1.09	$1.15	$1.26	$0.42	$0.37
2006 Averages	$7.24	$66.09	$0.66	$1.01	$1.20	$1.24	$1.44	$0.47	$0.41
2007									
1st Quarter	$6.77	$58.02	$0.59	$0.97	$1.13	$1.22	$1.37	$0.45	$0.40
2nd Quarter	$7.55	$64.97	$0.72	$1.13	$1.33	$1.45	$1.65	$0.51	$0.46
3rd Quarter	$6.16	$75.48	$0.82	$1.23	$1.44	$1.49	$1.68	$0.52	$0.46
4th Quarter	$6.97	$90.75	$1.04	$1.51	$1.79	$1.80	$2.01	$0.59	$0.54
2007 Averages	$6.86	$72.30	$0.79	$1.21	$1.42	$1.49	$1.68	$0.52	$0.47

(1) Natural gas, NGL, polymer grade propylene and refinery grade propylene prices represent an average of various commercial index prices including Oil Price Information Service ("OPIS") and Chemical Market Associates, Inc. ("CMAI"). Natural gas price is representative of Henry-Hub I-FERC. NGL prices are representative of Mont Belvieu Non-TET pricing. Polymer-grade propylene represents average CMAI contract pricing. Refinery grade propylene represents an average of CMAI spot prices.

(2) Crude oil price is representative of an index price for West Texas Intermediate.

The following table presents our significant average throughput, production and processing volumetric data. These statistics are reported on a net basis, taking into account our ownership interests in certain joint ventures and reflect the periods in which we owned an interest in such operations. These statistics include volumes for newly constructed assets since the dates such assets were placed into service and for recently purchased assets since the date of acquisition.

	For the Year Ended December 31,		
	2007	2006	2005
NGL Pipelines & Services, net:			
NGL transportation volumes (MBPD)	1,666	1,577	1,478
NGL fractionation volumes (MBPD)	394	312	292
Equity NGL production (MBPD) (1)	88	63	68
Fee-based natural gas processing (MMcf/d)	2,565	2,218	1,767
Onshore Natural Gas Pipelines & Services, net:			
Natural gas transportation volumes (BBtus/d)	6,632	6,012	5,916
Offshore Pipelines & Services, net:			
Natural gas transportation volumes (BBtus/d)	1,641	1,520	1,780
Crude oil transportation volumes (MBPD)	163	153	127
Platform gas processing (MMcf/d)	494	159	252
Platform oil processing (MBPD)	24	15	7
Petrochemical Services, net:			
Butane isomerization volumes (MBPD)	90	81	81
Propylene fractionation volumes (MBPD)	68	56	55
Octane additive production volumes (MBPD)	9	9	6
Petrochemical transportation volumes (MBPD)	105	97	64
Total, net:			
NGL, crude oil and petrochemical transportation volumes (MBPD)	1,934	1,827	1,669
Natural gas transportation volumes (BBtus/d)	8,273	7,532	7,696
Equivalent transportation volumes (MBPD) (2)	4,111	3,809	3,694

(1) Volumes for 2005 have been revised to incorporate asset-level definitions of equity NGL production volumes.

(2) Reflects equivalent energy volumes where 3.8 MMBtus of natural gas are equivalent to one barrel of NGLs.

Comparison of Results of Operations

The following table summarizes the key components of our results of operations for the periods indicated (dollars in thousands):

	For the Year Ended December 31, 2007	2006	2005
Revenues	$16,950,125	$13,990,969	$12,256,959
Operating costs and expenses	16,009,051	13,089,091	11,546,225
General and administrative costs	87,695	63,391	62,266
Equity in income of unconsolidated affiliates	29,658	21,565	14,548
Operating income	883,037	860,052	663,016
Interest expense	311,764	238,023	230,549
Provision for income taxes	15,257	21,323	8,362
Minority interest	30,643	9,079	5,760
Net income	533,674	601,155	419,508

Our gross operating margin by segment and in total is as follows for the periods indicated (dollars in thousands):

	For the Year Ended December 31, 2007	2006	2005
Gross operating margin by segment:			
NGL Pipelines & Services	$ 812,521	$ 752,548	$ 579,706
Onshore Natural Gas Pipelines & Services	335,683	333,399	353,076
Offshore Pipeline & Services	171,551	103,407	77,505
Petrochemical Services	172,313	173,095	126,060
Total segment gross operating margin	$1,492,068	$1,362,449	$1,136,347

For a reconciliation of non-GAAP gross operating margin to GAAP operating income and further to GAAP income before provision for income taxes, minority interest and the cumulative effect of changes in accounting principles, see "Other Items — Non-GAAP reconciliations" included within this Item 7.

The following table summarizes the contribution to consolidated revenues from the sale of NGL, natural gas and petrochemical products during the periods indicated (dollars in thousands):

	For the Year Ended December 31, 2007	2006	2005
NGL Pipelines & Services:			
Sale of NGL products	$11,822,291	$9,496,926	$8,176,370
Percent of consolidated revenues	70%	68%	67%
Onshore Natural Gas Pipelines & Services:			
Sale of natural gas	$ 1,633,214	$1,228,916	$1,065,542
Percent of consolidated revenues	10%	9%	9%
Petrochemical Services:			
Sale of petrochemical products	$ 1,796,251	$1,545,693	$1,311,956
Percent of consolidated revenues	11%	11%	11%

Comparison of 2007 with 2006

Revenues for 2007 were $16.95 billion compared to $13.99 billion for 2006. The increase in consolidated revenues year-to-year is primarily due to higher sales volumes and energy commodity prices in 2007 relative to 2006. These factors accounted for a $2.98 billion increase in consolidated revenues associated with our marketing activities. Revenues from business interruption insurance proceeds totaled $36.1 million in 2007 compared to $63.9 million in 2006.

Operating costs and expenses were $16.01 billion for 2007 versus $13.09 billion for 2006. The year-to-year increase in consolidated operating costs and expenses is primarily due to an increase in the cost of sales associated with our marketing activities. The cost of sales of our NGL, natural gas and petrochemical products increased $2.46 billion year-to-year as a result of an increase in volumes and higher energy commodity prices. Operating costs and expenses associated with our natural gas processing plants increased $185.7 million year-to-year as a result of higher energy commodity prices in 2007 relative to 2006. Operating costs and expenses associated with assets we constructed and placed into service or acquired since January 1, 2006 increased $188.1 million year-to-year.

General and administrative costs were $87.7 million for 2007 compared to $63.4 million for 2006. The $24.3 million year-to-year increase in general and administrative costs is primarily due to the recognition of a severance obligation during 2007 and an increase in legal fees.

Changes in our revenues and costs and expenses year-to-year are explained in part by changes in energy commodity prices. The weighted-average indicative market price for NGLs was $1.19 per gallon during 2007 versus $1.00 per gallon during 2006, a year-to-year increase of 19%. Our determination of the weighted-average indicative market price for NGLs is based on U.S. Gulf Coast prices for such products at Mont Belvieu, which is the primary industry hub for domestic NGL production. The market price of natural gas (as measured at Henry Hub) averaged $6.86 per MMBtu during 2007 versus $7.24 per MMBtu during 2006. For additional historical energy commodity pricing information, see the table on page 58.

Equity earnings from unconsolidated affiliates were $29.7 million for 2007 compared to $21.6 million for 2006. Equity earnings from our investment in Jonah increased $9.1 million year-to-year. Equity earnings for 2007 include a non-cash impairment charge of $7.0 million associated with our investment in Nemo compared to a non-cash impairment charge of $7.4 million in 2006 related to our investment in Neptune. Collectively, equity earnings from our other unconsolidated affiliates decreased $1.4 million year-to-year primarily due to the sale of our investment in Coyote Gas Treating, LLC in August 2006.

Operating income for 2007 was $883.0 million compared to $860.1 million for 2006. Collectively, the aforementioned changes in revenues, costs and expenses and equity earnings contributed to the $22.9 million increase in operating income year-to-year.

Interest expense increased $73.7 million year-to-year primarily due to our issuance of junior subordinated notes in the second quarter of 2007 and third quarter of 2006 and the issuance of Senior Notes L in the third quarter of 2007. Our consolidated interest expense for 2007 includes $11.6 million associated with Duncan Energy Partners' credit facility. Our average debt principal outstanding was $6.26 billion in 2007 compared to $4.93 billion in 2006. Minority interest increased $21.6 million year-to-year attributable to the public unit holders of Duncan Energy Partners and third-party ownership interests in the Independence Hub platform.

As a result of items noted in the previous paragraphs, our consolidated net income decreased $67.5 million year-to-year to $533.7 million in 2007 compared to $601.2 million in 2006. Net income for 2006 includes a $1.5 million benefit relating to the cumulative effect of change in accounting principle. For additional information regarding the cumulative effect of change in accounting principle we recorded in 2006, see Note 8 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

The following information highlights significant year-to-year variances in gross operating margin by business segment:

NGL Pipelines & Services. Gross operating margin from this business segment was $812.5 million for 2007 compared to $752.5 million for 2006. Gross operating margin for 2007 includes $32.7 million of proceeds from business interruption insurance claims compared to $40.4 million of proceeds during 2006. Strong demand for NGLs in 2007 compared to 2006 led to higher natural gas processing margins, increased volumes of natural gas processed under fee-based contracts and higher NGL throughput volumes at certain of our pipelines and fractionation facilities. The following paragraphs provide a discussion of segment results excluding proceeds from business interruption insurance claims.

Gross operating margin from NGL pipelines and storage was $302.2 million for 2007 compared to $265.7 million for 2006. Total NGL transportation volumes increased to 1,666 MBPD during 2007 from 1,577 MBPD during 2006. The $36.5 million year-to-year increase in gross operating margin is primarily due to higher pipeline transportation and NGL storage volumes at certain of our facilities and higher transportation fees charged to shippers on our Mid-America Pipeline System. Our DEP South Texas NGL Pipeline contributed $21.1 million of gross operating margin and 73 MBPD of NGL transportation volumes during 2007. The increase in gross operating margin year-to-year was partially offset by lower volumes and higher costs resulting from the November 2007 rupture of the Dixie Pipeline and a one-time benefit in 2006 for the settlement of a pipeline contamination incident.

Gross operating margin from our natural gas processing and related NGL marketing business was $389.1 million for 2007 compared to $359.7 million for 2006. The $29.4 million increase in gross operating margin year-to-year is largely due to improved results from our south Texas, Louisiana and Chaco natural gas processing facilities attributable to higher volumes and equity NGL sales revenues. Fee-based processing volumes increased to 2.6 Bcf/d during 2007 from 2.2 Bcf/d during 2006. Equity NGL production increased to 88 MBPD during 2007 from 63 MBPD during 2006. The year-to-year increase in gross operating margin from this business was partially offset by expenses associated with start-up delays at our Meeker and Pioneer natural gas processing plants.

The start-up delays at both our Meeker and Pioneer facilities are attributable to the replacement of defective high pressure valves and the need to address third-party engineering design problems. We are actively engaged in efforts to obtain recovery for certain of our losses. During 2007, we entered into transactions to economically hedge a percentage of the expected NGL production at these facilities, which entailed the physical forward sale of NGLs and the purchase of natural gas. As a result of the unexpected downtime at our Meeker facility and the delayed start-up of our Pioneer facility, the actual NGL production and natural gas consumption during the fourth quarter of 2007 was less than the volume we hedged. The cost to replace the defective valves and the expense resulting from a non-cash, mark-to-market charge on the short, or over hedged, NGL balance and the liquidation of the long natural gas position totaled $30.0 million during 2007. Gross operating margin generated by our Meeker facility from actual production was offset by a decrease in gross operating margin from our NGL marketing business.

Gross operating margin from NGL fractionation was $88.4 million for 2007 compared to $86.8 million for 2006. Fractionation volumes increased from 312 MBPD during 2006 to 394 MBPD during 2007. The year-to-year increase in gross operating margin of $1.6 million is primarily due to higher volumes at our Norco NGL fractionator during 2007 relative to 2006. Our Norco NGL fractionator returned to normal operating rates in the second quarter of 2006 after suffering a reduction of fractionation volumes due to the effects of Hurricane Katrina. Gross operating margin attributable to our Hobbs NGL fractionator, which became operational in August 2007, was largely offset by start-up expenses. Fractionation volumes for 2007 include 36 MBPD from our Hobbs fractionator.

Onshore Natural Gas Pipelines & Services. Gross operating margin from this business segment was $335.7 million for 2007 compared to $333.4 million for 2006. Our total onshore natural gas transportation volumes were 6,632 BBtu/d for 2007 compared to 6,012 BBtu/d for 2006. Gross operating margin from our onshore natural gas pipeline business was $307.2 million for 2007 compared to $312.3 million for 2006. The $5.1 million year-to-year decrease in gross operating margin from this business is largely due to higher operating costs on our Acadian Gas System, Waha and Carlsbad Gathering Systems and our Texas Intrastate System.

Results from our onshore natural gas pipeline business for 2007 include $5.5 million of gross operating margin from our Piceance Creek Gathering System, which we acquired in December 2006. Equity earnings from our investment in Jonah increased $9.1 million year-to-year. The Piceance Creek Gathering System and our net share of the gathering volumes on the Jonah Gathering System contributed 789 BBtu/d, collectively, of natural gas gathering volumes during 2007.

Gross operating margin from our natural gas storage business was $28.4 million for 2007 compared to $21.1 million for 2006. The $7.3 million year-to-year increase in gross operating margin is largely due to improved results from our Wilson natural gas storage facility attributable to lower repair costs in 2007 relative to 2006 and a 2006 loss on the sale of cushion gas. All repairs are now complete on the three storage wells at our Wilson facility that were taken out of service in the second quarter of 2006. We are in the process of dewatering the caverns and returning working gas storage capacity to service, which should be largely complete in the second quarter of 2008. Gross operating margin from our Petal facility includes an $8.4 million benefit in 2006 for a well measurement gain.

Offshore Pipelines & Services. Gross operating margin from this business segment was $171.6 million for 2007 compared to $103.4 million for 2006, a year-to-year increase of $68.2 million. Our Independence project contributed $85.0 million of gross operating margin during 2007 on average natural gas throughput of 423 BBtus/d. Segment gross operating margin for 2007 includes $3.4 million of proceeds from business interruption insurance claims compared to $23.5 million of proceeds in 2006. The following paragraphs provide a discussion of segment results excluding proceeds from business interruption insurance claims.

Gross operating margin from our offshore platform services business was $111.7 million for 2007 compared to $34.6 million for 2006. The $77.1 million year-to-year increase in gross operating margin is primarily due to our start up of the Independence Hub Platform in 2007, which contributed $63.6 million of gross operating margin in 2007. In addition, gross operating margin from this business increased $13.5 million year-to-year primarily due to higher volumes during 2007 versus 2006. Our net platform natural gas processing volumes increased to 494 MMcf/d in 2007 from 159 MMcf/d in 2006.

Gross operating margin from our offshore natural gas pipeline business was $35.4 million for 2007 compared to $22.4 million for 2006. Offshore natural gas transportation volumes were 1,641 BBtu/d during 2007 versus 1,520 BBtu/d during 2006. Our Independence Trail Pipeline reported $21.4 million of gross operating margin and 423 BBtus/d of transportation volumes for 2007. Results from our Independence Trail Pipeline were partially offset by a decrease in volumes and revenues from our Viosca Knoll Gathering System and Constitution Gas Pipeline. Gross operating margin for 2007 includes a non-cash impairment charge of $7.0 million associated with our investment in Nemo compared to charge of $7.4 million in 2006 related to our investment in Neptune.

Gross operating margin from our offshore crude oil pipeline business was $21.1 million for 2007 versus $23.0 million for 2006. The $1.9 million year-to-year decrease in gross operating margin is primarily due to lower transportation volumes on our certain of our offshore crude oil pipelines and higher operating costs on our Poseidon Oil Pipeline System during 2007 relative to 2006. An increase in revenues year-to-year on our Cameron Highway Oil Pipeline System attributable to higher volumes was more than offset by a one-time expense of $8.8 million associated with the early termination of Cameron Highway's credit facility. Crude oil transportation volumes on our Cameron Highway Oil Pipeline System net to our ownership interest were 44 MBPD during 2007 compared to 32 MBPD during 2006. Total offshore crude oil transportation volumes were 163 MBPD during 2007 versus 153 MBPD during 2006.

BP P.L.C. announced in December 2007 that crude oil and natural gas production from its Atlantis Development had commenced. Crude oil volumes from this development are transported on our Cameron Highway Oil Pipeline System. Natural gas production from the Atlantis development is transported on our Manta Ray Gathering System and Nautilus Pipeline and processed at our Neptune facility. Recovered NGLs are fractionated at our Promix fractionator.

Petrochemical Services. Gross operating margin from this business segment was $172.3 million for 2007 compared to $173.1 million for 2006. Gross operating margin from our butane isomerization business was $91.4 million for 2007 compared to $73.2 million for 2006. The $18.2 million year-to-year increase in gross operating margin is attributable to higher processing volumes and by-products sales revenues. Butane isomerization volumes were 90 MBPD for 2007 compared to 81 MBPD for 2006.

Gross operating margin from our propylene fractionation and pipeline activities was $62.6 million for 2007 versus $63.4 million for 2006. The $0.8 million year-to-year decrease in gross operating margin is primarily attributable to higher operating costs and expenses attributable to our propylene pipelines and our propylene storage and export facility. Petrochemical transportation volumes were 105 MBPD during 2007 compared to 97 MBPD during 2006. Gross operating margin from octane enhancement was $18.3 million for 2007 compared to $36.6 million for 2006. The year-to-year decrease of $18.3 million is primarily due to lower sales margins in 2007 relative to 2006. Octane enhancement production was 9 MBPD during 2007 and 2006.

Comparison of 2006 with 2005

Revenues for 2006 were $13.99 billion compared to $12.26 billion for 2005. The increase in consolidated revenues year-to-year is primarily due to higher sales volumes and energy commodity prices in 2006 relative to 2005. These factors accounted for a $1.72 billion increase in consolidated revenues associated with our marketing activities. Revenues for 2006 include $63.9 million of proceeds from business interruption insurance claims compared to $4.8 million of proceeds for 2005.

Operating costs and expenses were $13.09 billion for 2006 versus $11.55 billion for 2005. The year-to-year increase in consolidated operating costs and expenses is primarily due to an increase in the cost of sales associated with our marketing activities. The cost of sales of our NGL and petrochemical products increased $1.21 billion year-to-year as a result of an increase in volumes and higher energy commodity prices. Operating costs and expenses associated with our natural gas processing plants increased $258.7 million as a result of higher energy commodity prices in 2006 relative to 2005. General and administrative costs increased $1.1 million year-to-year primarily due to higher costs associated with FERC rate case filings for our Mid-America Pipeline System and Texas Intrastate System.

Changes in our revenues and costs and expenses year-to-year are explained in part by changes in energy commodity prices. The weighted-average indicative market price for NGLs was $1.00 per gallon during 2006 versus $0.91 per gallon during 2005, a year-to-year increase of 10%. The Henry Hub market price of natural gas averaged $7.24 per MMBtu during 2006 versus $8.64 per MMBtu during 2005. Polymer grade and refinery grade propylene index prices increased 12% year-to-year.

Equity earnings from unconsolidated affiliates were $21.6 million for 2006 compared to $14.5 million for 2005. An increase in volumes from offshore production led to a collective $11.8 million increase year-to-year in equity earnings from Poseidon and Deepwater Gateway. Equity earnings from Cameron Highway increased $4.9 million year-to-year. Our equity earnings for 2005 included an $11.5 million charge associated with the refinancing of Cameron Highway's project finance debt. Also, equity earnings from our investment in Neptune decreased $10.3 million year-to-year primarily due to a $7.4 million non-cash impairment charged recorded in 2006 associated with this investment.

Operating income for 2006 was $860.1 million compared to $663.0 million for 2005. Collectively, the aforementioned changes in revenues, costs and expenses and equity earnings contributed to the $197.1 million increase in operating income year-to-year.

Interest expense increased $7.5 million year-to-year primarily due to our issuance of junior notes in 2006 and an increase in interest rates charged on our variable rate debt. Our average debt principal outstanding was $4.93 billion in 2006 compared to $4.63 billion in 2005.

As a result of items noted in the previous paragraphs, our consolidated net income increased $181.6 million year-to-year to $601.2 million in 2006 compared to $419.5 million in 2005. Net income for both years includes the recognition of non-cash amounts related to the cumulative effect of changes in accounting principles. We recorded a $1.5 million benefit in 2006 and a $4.2 million charge in 2005 related to such changes. For additional information regarding the cumulative effect of changes in accounting principles we recorded in 2006 and 2005, see Note 8 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

The following information highlights significant year-to-year variances in gross operating margin by business segment:

NGL Pipelines & Services. Gross operating margin from this business segment was $752.5 million for 2006 compared to $579.7 million for 2005. Gross operating margin for 2006 includes $40.4 million of proceeds from business interruption insurance claims compared to $4.8 million of proceeds during 2005. Strong demand for NGLs in 2006 compared to 2005 led to higher natural gas processing margins, increased volumes of natural gas processed under fee-based contracts and higher NGL throughput volumes at certain of our pipelines and fractionation facilities. The following paragraphs provide a discussion of segment results excluding proceeds from business interruption proceeds.

Gross operating margin from NGL pipelines and storage was $265.7 million for 2006 compared to $205.0 million for 2005. Total NGL transportation volumes increased to 1,577 MBPD during 2006 from 1,478 MBPD during 2005. The $60.7 million year-to-year increase in gross operating margin is primarily due to higher NGL transportation and storage volumes at certain of our facilities and the affects of a higher average transportation rate charged to shippers on our Mid-America pipeline. Also, segment gross operating margin in 2006 from our Dixie pipeline system benefited from lower pipeline integrity and maintenance costs year-to-year and the settlement of claims associated with a pipeline contamination incident in 2005.

Gross operating margin from our natural gas processing and related NGL marketing business was $359.6 million for 2006 compared to $308.5 million for 2005. The $51.1 million increase in gross operating margin year-to-year is largely due to improved results from our south Texas and Louisiana natural gas processing facilities, which benefited from strong demand for NGLs, a favorable processing environment and higher levels of offshore natural gas production available for processing. Fee-based processing volumes increased to 2.2 Bcf/d during 2006 from 1.8 Bcf/d during 2005. Lastly, gross operating margin from natural gas processing for 2006 includes $9.6 million from processing contracts we acquired in connection with the Encinal acquisition in July 2006 and $9.4 million from the Pioneer facility, which we acquired from TEPPCO in March 2006.

Gross operating margin from NGL fractionation was $86.8 million for 2006 compared to $61.5 million for 2005. Fractionation volumes increased from 292 MBPD during 2005 to 312 MBPD during 2006. The year-to-year increase in gross operating margin of $25.3 million is largely due to increased fractionation volumes at our Norco NGL fractionator. This facility suffered a reduction of volumes in the second half of 2005 due to the effects of Hurricanes Katrina and Rita. Also, our Mont Belvieu NGL fractionator benefited from a 15 MBPD expansion project that was completed during the second quarter of 2006.

Onshore Natural Gas Pipelines & Services. Gross operating margin from this business segment was $333.4 million for 2006 compared to $353.1 million for 2005. Our total onshore natural gas transportation volumes were 6,012 BBtu/d during 2006 compared to 5,916 BBtu/d for 2005. A $24.7 million increase in segment gross operating margin from our Texas Intrastate System year-to-year was more than offset by lower gross operating margin from our San Juan Gathering System and Wilson natural gas storage facility. Gross operating margin from our Texas Intrastate System increased to $117.7 million for 2006 from $93 million for 2005 due to higher transportation fees and lower operating costs year-to-year.

Segment gross operating margin from our San Juan Gathering System decreased $26.7 million year-to-year attributable to lower revenues from certain gathering contracts in which the fees are based on an index price for natural gas. Average index prices for natural gas were significantly higher during 2005 relative to 2006 due to supply interruptions and higher regional demand caused by Hurricanes Katrina and Rita. Natural gas gathering volumes for the San Juan Gathering System were 1,192 BBtu/d for 2006 and 1,186 BBtu/d for 2005.

In addition, gross operating margin from this segment decreased $21.9 million year-to-year as a result of mechanical problems associated with three storage caverns located at our Wilson natural gas storage facility in Texas, which caused these wells to be taken out of service for most of 2006. This includes $7.9 million in losses associated with the sale of cushion gas from these wells.

Lastly, gross operating margin for 2006 includes $1.8 million from the Encinal natural gas gathering system that we acquired in July 2006. The Encinal natural gas gathering system contributed 89 BBtu/d of gathering volumes during 2006.

Offshore Pipelines & Services. Gross operating margin from this business segment was $103.4 million for 2006 compared to $77.5 million for 2005. Segment gross operating margin for 2006 includes $23.5 million of proceeds from business interruption insurance claims. As a result of industry losses associated with these storms, insurance costs for offshore operations have increased dramatically. Insurance costs for our offshore assets were $21.6 million for 2006 compared to $6.5 million for 2005. The following paragraphs provide a discussion of segment results excluding proceeds from business interruption proceeds.

Gross operating margin from our offshore crude oil pipelines was $23.0 million for 2006 versus $0.3 million for 2005. Our Marco Polo and Poseidon oil pipelines posted higher crude oil transportation volumes during 2006 due to increased production activity by our customers. Collectively, gross operating margin from the Marco Polo and Poseidon oil pipelines improved $10.1 million year-to-year. Our Constitution Oil Pipeline, which was placed into service during the first quarter of 2006, contributed $8.8 million to segment gross operating margin during 2006. Total offshore crude oil transportation volumes were 153 MBPD during 2006 versus 127 MBPD during 2005.

Gross operating margin from our offshore natural gas pipelines was $22.4 million for 2006 compared to $37.1 million for 2005. Offshore natural gas transportation volumes were 1,520 BBtu/d during 2006 versus 1,780 BBtu/d during 2005. The $14.7 million decrease in gross operating margin year-to-year is largely due to increased insurance costs and a non-cash impairment charge of $7.4 million recorded in 2006 associated with our investment in Neptune. Also, 2006 includes gross operating margin of $8.4 million and transportation volumes of 50 BBtu/d from the Constitution natural gas pipeline, which was placed in service during the first quarter of 2006.

Gross operating margin from our offshore platforms was $34.5 million for 2006 compared to $40.1 million for 2005. The decrease in gross operating margin year-to-year is primarily due to reduced offshore production during 2006 compared to 2005 as a result of Hurricanes Katrina and Rita. Equity earnings from Deepwater Gateway, which owns the Marco Polo platform, increased $7.8 million year-to-year primarily due to higher processing volumes.

Petrochemical Services. Gross operating margin from this business segment was $173.1 million for 2006 compared to $126.1 million for 2005. The $47.0 million year-to-year increase in gross operating margin is primarily due to improved results from our octane enhancement business attributable to higher isooctane sales volumes and prices. Gross operating margin from this business was $36.6 million for 2006 compared to $3.6 million for 2005. Isooctane, a high octane, low vapor pressure motor gasoline additive, complements the increasing use of ethanol, which has a high vapor pressure. Our isooctane production facility commenced operations in the second quarter of 2005.

Gross operating margin from our propylene fractionation and pipeline activities was $63.4 million for 2006 versus $55.9 million for 2005. The year-to-year increase in gross operating margin of $7.5 million is primarily due to improved polymer grade propylene sales prices and volumes and the addition of the Texas City refinery-grade propylene pipeline, which we completed during 2005. Petrochemical transportation volumes were 97 MBPD during 2006 compared to 64 MBPD during 2005. Gross operating margin from butane isomerization was $73.2 million for 2006 compared to $66.6 million for 2005. The year-to-year increase of $6.6 million is primarily due to higher processing fees and lower fuel costs. Butane isomerization volumes were 81 MBPD during 2006 and 2005.

General Outlook for 2008

We are currently in a major asset construction phase that began in 2005. Fiscal 2007 was a transitional year as we completed construction of several major projects and placed them into service for a portion of 2007. These projects included the Independence Hub platform and Trail pipeline, Meeker natural gas processing plant, Hobbs NGL fractionator, expansion of Mid-America NGL pipeline and a new propylene fractionator at Mont Belvieu. Additionally, in February 2008, we placed the Pioneer cryogenic natural gas processing plant in service. In 2008, we expect these major projects to contribute significant new sources of revenue, operating income and cash flow from operations as volumes increase to these facilities.

During the second half of 2008, construction of additional growth projects should be completed; placed in service and begin to contribute new sources of revenue, operating income and cash flow from operations. These include the expansion of the Meeker natural gas processing plant, Exxon central treating facility and the Sherman Extension natural gas pipeline.

We are continuing to work to expand our relationships with existing customers and pursue service agreements with new customers that would provide additional volumes to both our existing and newly constructed assets. Based on current general and industry economic conditions,

- We believe that drilling and production activities in the major producing areas where we operate, including the Gulf of Mexico and supply basins in Texas, San Juan and the Rocky Mountains, could result in increased demand for our midstream energy services. As a result, we expect higher transportation and processing volumes for certain of our existing and newly constructed assets due to increased natural gas, NGL and crude oil production from both onshore and offshore producing areas.

- We expect the volume of natural gas and NGLs available to our facilities in Texas to increase as a result of drilling activity and long-term agreements executed with new customers. We expect natural gas transportation volumes on our Texas Intrastate System to increase during 2008 as we supply the Houston, Texas area with natural gas volumes under a long-term agreement with CenterPoint Energy and begin operations on the Sherman Extension pipeline in the Barnett Shale region of North Texas in the fourth quarter of 2008.

- We believe that the current strength of the domestic and global economies should continue to drive increased demand for all forms of energy despite fluctuating commodity prices. Our largest NGL consuming customers in the ethylene industry continue to see strong demand for their products. Ethane and propane continue to be the preferred feedstocks for the ethylene industry due to the higher cost of crude oil derivatives.

- Longer term, we believe the expansion of crude oil refineries on the U.S. Gulf Coast could result in opportunities to provide additional midstream services through our existing assets and support the construction of new pipeline and storage facilities.

Liquidity and Capital Resources

Our primary cash requirements, in addition to normal operating expenses and debt service, are for working capital, capital expenditures, business acquisitions and distributions to our partners. We expect to fund our short-term needs for such items as operating expenses and sustaining capital expenditures with operating cash flows and short-term revolving credit arrangements. Capital expenditures for long-term needs resulting from internal growth projects and business acquisitions are expected to be funded by a variety of sources (either separately or in combination) including net cash flows provided by operating activities, borrowings under credit facilities, the issuance of additional equity and debt securities and proceeds from divestitures of ownership interest in assets to affiliates or third parties. We expect to fund cash distributions to partners primarily with operating cash flows. Our debt service requirements are expected to be funded by operating cash flows and/or refinancing arrangements.

At December 31, 2007, we had $39.7 million of unrestricted cash on hand and approximately $1.02 billion of available credit under EPO's Multi-Year Revolving Credit Facility. In total, we had approximately $6.90 billion in principal outstanding under consolidated debt agreements at December 31, 2007. For detailed information regarding our consolidated debt obligations and those of our unconsolidated affiliates, see Note 14 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

As a result of our growth objectives, we expect to access debt and equity capital markets from time-to-time and we believe that financing arrangements to support our growth activities can be obtained on reasonable terms. Furthermore, we believe that maintenance of an investment grade credit rating combined with continued ready access to debt and equity capital at reasonable rates and sufficient trade credit to operate our businesses efficiently provide a solid foundation to meet our long and short-term liquidity and capital resource requirements.

Registration Statements

We may issue equity or debt securities to assist us in meeting our liquidity and capital spending requirements. Duncan Energy Partners may do likewise in meeting its liquidity and capital spending requirements. Enterprise Products Partners L.P. and EPO have a universal shelf registration statement on file with the U.S. Securities and Exchange Commission ("SEC") that would allow these entities to issue an unlimited amount of debt and equity securities for general partnership purposes.

During 2003, we instituted a distribution reinvestment plan ("DRIP"). We have a registration statement on file with the SEC covering the issuance of up to 25,000,000 common units in connection with the DRIP. The DRIP provides unitholders of record and beneficial owners of our common units a voluntary means by which they can increase the number of common units they own by reinvesting the quarterly cash distributions they would otherwise receive into the purchase of additional common units. During the year ended December 31, 2007, we issued 1,923,640 common units in connection with our DRIP, which generated proceeds of $56.3 million from plan participants.

We also have a registration statement on file related to our employee unit purchase plan, under which we can issue up to 1,200,000 common units. Under this plan, employees of EPCO can purchase our common units at a 10% discount through payroll deductions. During the year ended December 31, 2007, we issued 132,975 common units to employees under this plan, which generated proceeds of $4.0 million.

In February 2007, Duncan Energy Partners completed its initial public offering of 14,950,000 common units, the majority of proceeds from which were distributed to us. Duncan Energy Partners may issue additional amounts of equity in the future in connection with other acquisitions. For additional information regarding Duncan Energy Partners, see "Other Items — Initial Public Offering of Duncan Energy Partners" within this Item 7.

For information regarding our public debt obligations or partnership equity, see Notes 14 and 15, respectively, of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Credit Ratings of EPO

At February 1, 2008, the investment-grade credit ratings of EPO's debt securities were Baa3 by Moody's Investor Services; BBB- by Fitch Ratings; and BBB- by Standard and Poor's. A rating reflects only the view of a rating agency and is not a recommendation to buy, sell or hold any security. Any rating can be revised upward or downward or withdrawn at any time by a rating agency if it determines that the circumstances warrant such a change and should be evaluated independently of any other rating.

Based on the characteristics of the $1.25 billion of fixed/floating unsecured junior subordinated notes that EPO issued in 2006 and 2007, the rating agencies assigned partial equity treatment to the notes.

Moody’s Investor Services and Standard and Poor’s each assigned 50% equity treatment and Fitch Ratings assigned 75% equity treatment.

In connection with the construction of our Pascagoula, Mississippi natural gas processing plant, EPO entered into a $54 million, ten-year, fixed-rate loan with the Mississippi Business Finance Corporation ("MBFC"). The indenture agreement for this loan contains an acceleration clause whereby if EPO’s credit rating by Moody’s Investor Services declines below Baa3 in combination with our credit rating at Standard & Poor’s declining below BBB-, the $54.0 million principal balance of this loan, together with all accrued and unpaid interest would become immediately due and payable 120 days following such event. If such an event occurred, EPO would have to either redeem the Pascagoula MBFC Loan or provide an alternative credit agreement to support its obligation under this loan.

Cash Flows from Operating, Investing and Financing Activities

The following table summarizes our cash flows from operating, investing and financing activities for the periods indicated (dollars in thousands). For information regarding the individual components of our cash flow amounts, see the Statements of Consolidated Cash Flows included under Item 8 of this annual report.

	For the Year Ended December 31,		
	2007	2006	2005
Net cash flows provided by operating activities	$1,590,941	$1,175,069	$ 631,708
Cash used in investing activities	2,533,607	1,689,288	1,130,395
Cash provided by financing activities	979,355	494,972	516,229

Net cash flows provided by operating activities is largely dependent on earnings from our business activities. As a result, these cash flows are exposed to certain risks. We operate predominantly in the midstream energy industry. We provide services for producers and consumers of natural gas, NGLs and crude oil. The products that we process, sell or transport are principally used as fuel for residential, agricultural and commercial heating; feedstocks in petrochemical manufacturing; and in the production of motor gasoline. Reduced demand for our services or products by industrial customers, whether because of general economic conditions, reduced demand for the end products made with our products or increased competition from other service providers or producers due to pricing differences or other reasons could have a negative impact on our earnings and thus the availability of cash from operating activities. For a more complete discussion of these and other risk factors pertinent to our business, see Item 1A of this annual report.

Our Statements of Consolidated Cash Flows are prepared using the indirect method. The indirect method derives net cash flows from operating activities by adjusting net income to remove (i) the effects of all deferrals of past operating cash receipts and payments, such as changes during the period in inventory, deferred income and similar transactions, (ii) the effects of all accruals of expected future operating cash receipts and cash payments, such as changes during the period in receivables and payables, (iii) the effects of all items classified as investing or financing cash flows, such as gains or losses on sale of property, plant and equipment or extinguishment of debt, and (iv) other non-cash amounts such as depreciation, amortization, operating lease expense paid by EPCO and changes in the fair market value of financial instruments. Equity in income from unconsolidated affiliates is also a non-cash item that must be removed in determining net cash provided by operating activities. Our cash flows from operating activities reflect the actual cash distributions we receive from such investees.

In general, the net effect of changes in operating accounts results from the timing of cash receipts from sales and cash payments for purchases and other expenses during each period. Increases or decreases in inventory are influenced by the quantity of products held in connection with our marketing activities and changes in energy commodity prices.

Cash used in investing activities primarily represents expenditures for capital projects, business combinations, asset purchases and investments in unconsolidated affiliates. Cash provided by (or used in) financing activities generally consists of borrowings and repayments of debt, distributions to partners and proceeds from the issuance of equity securities. Amounts presented in our Statements of Consolidated Cash Flows for borrowings and repayments under debt agreements are influenced by the magnitude of cash receipts and payments under our revolving credit facilities.

The following information highlights the significant year-to-year variances in our cash flow amounts:

Comparison of 2007 with 2006

Operating activities. Net cash flow provided by operating activities was $1.59 billion for the year ended December 31, 2007 compared to $1.18 billion for the year ended December 31, 2006.

- Our net cash flows from consolidated businesses (excluding cash payments for interest and taxes and distributions received from unconsolidated affiliates) increased $436.9 million year-to-year. The improvement in cash flow is generally due to increased gross operating margin (see "Results of Operations" within this Item 7) and the timing of related cash collections and disbursements between periods. The $436.9 million year-to-year increase also includes a $42.1 million increase in cash proceeds we received from insurance claims related to certain named storms. See Note 21 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding insurance matters.
- Cash distributions received from unconsolidated affiliates increased $30.6 million year-to-year primarily due to improved earnings from our Gulf of Mexico investments, which were negatively impacted during the year ended December 31, 2006 as a result of the lingering effects of Hurricanes Katrina and Rita.
- Cash payments for interest increased $56.2 million year-to-year primarily due to increased borrowings to finance our capital spending program. Our average debt balance for the year ended December 31, 2007 was $6.26 billion compared to $4.93 billion for the year ended December 31, 2006.
- Cash payments for federal and state income taxes decreased $4.7 million year-to-year.

Investing activities. Cash used in investing activities was $2.55 billion for the year ended December 31, 2007 compared to $1.69 billion for the year ended December 31, 2006. The $864.3 million year-to-year increase in cash outflows is primarily due to an $847.7 million increase in capital spending for property, plant and equipment and a $194.6 million increase in investments in unconsolidated affiliates, partially offset by a $240.7 million decrease in cash outlays for business combinations. For additional information related to our capital spending for property, plant and equipment, see "Capital Spending" included within this Item 7.

During the year ended December 31, 2007 we contributed $216.5 million to an unconsolidated affiliate, Cameron Highway Oil Pipeline Company ("Cameron Highway"). In return, Cameron Highway used these funds, along with an equal contribution from our 50% joint venture partner in Cameron Highway, to repay its $430.0 million in outstanding debt.

During the year ended December 31, 2006, we paid $100.0 million for a 100% interest in Piceance Creek Pipeline, LLC and paid Lewis Energy Group, L.P. ("Lewis") $145.2 million in cash in connection with the Encinal acquisition. Our spending for business combinations during the year ended December 31, 2007 was primarily limited to the $35.0 million we paid to acquire the South Monco pipeline business.

Financing activities. Cash provided by financing activities was $979.4 million for the year ended December 31, 2007 versus $495.0 million for the year ended December 31, 2006. The following information highlights significant factors that influenced the $484.4 million year-to-year change in cash provided by financing activities:

- Net borrowings under our consolidated debt agreements increased $1.10 billion year-to-year. In May 2007, EPO sold $700.0 million in principal amount of fixed/floating unsecured junior subordinated notes (Junior Notes B"). In September 2007, EPO sold $800.0 million in principal amount of fixed-rate unsecured senior notes ("Senior Notes L") and in October 2007, EPO repaid $500.0 million in principal amount of Senior Notes E. For information regarding our consolidated debt obligations, see Note 14 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

- Net proceeds from the issuance of our common units decreased $788.0 million year-to-year. We had underwritten equity offerings in March and September of 2006 that generated net proceeds of $750.8 million reflecting the sale of 31,050,000 common units.

- Contributions from minority interests increased $275.4 million year-to-year primarily due to the initial public offering of Duncan Energy Partners in February 2007, which generated net proceeds of $290.5 million from the sale of 14,950,000 of its common units. See "Other Items — Initial Public Offering of Duncan Energy Partners" within this Item 7 for additional information regarding this offering.

- Cash distributions to our partners increased $137.9 million year-to-year due to an increase in common units outstanding and our quarterly cash distribution rates.

- We received $48.9 million from the settlement of treasury lock contracts during the year ended December 31, 2007 related to our interest rate hedging activities.

Comparison of 2006 with 2005

Operating activities. Net cash flow provided by operating activities was $1.18 billion for the year ended December 31, 2006 compared to $631.7 million for the year ended December 31, 2006.

- Our net cash flows from consolidated businesses (excluding cash payments for interest and taxes and distributions received from unconsolidated affiliates) increased $569.6 million year-to-year. The improvement in cash flow is generally due to increased earnings (see "Results of Operations" within this Item 7) and the timing of related cash collections and disbursements between periods. The $569.6 million year-to-year increase also includes a $93.7 million increase in cash proceeds we received from insurance claims related to certain named storms.

- Cash distributions received from unconsolidated affiliates decreased $13.0 million year-to-year primarily due to the lingering effects of Hurricanes Katrina and Rita on our Gulf of Mexico investments during the year ended December 31, 2006.

- Cash payments for interest increased $7.9 million year-to-year. Our average debt balance for the year ended December 31, 2006 was $4.93 billion compared to $4.63 billion for the year ended December 31, 2005.

- Cash payments for federal and state income taxes increased $5.3 million year-to-year.

Investing activities. Cash used in investing activities was $1.7 billion for the year ended December 31, 2006 compared to $1.1 billion for the year ended December 31, 2005. Our cash outlays for business combinations were $276.5 million in 2006 versus $326.6 million in 2005. During the year ended December 31, 2006, we paid $100.0 million for a 100% interest in Piceance Creek Pipeline, LLC and paid Lewis $145.2 million in cash in connection with the Encinal acquisition. Our cash outlay for acquisitions during 2005 included (i) $145.5 million for storage assets purchased from Ferrellgas LP, (ii) $74.9 million for indirect interests in certain East Texas natural gas gathering and processing assets, (iii) $68.6 million for additional ownership interests in Dixie and (iv) $25.0 million for the remaining ownership interests in our Mid-America Pipeline System and an additional interest in the Seminole Pipeline.

Proceeds from the sale of assets during 2005 include $42.1 million from the sale of our investment in Starfish Pipeline Company, LLC ("Starfish"). We were required to divest our ownership interest in this entity by the Federal Trade Commission in order to gain its approval for our merger with GulfTerra Energy Partners, L.P. in September 2004. In addition, we received $47.5 million as a return of our investment in

Cameron Highway in June 2005. As a result of refinancing its project debt, Cameron Highway was authorized by its lenders to make this special distribution.

Investments in unconsolidated affiliates were $138.3 million for the year ended December 31, 2006 compared to $87.3 million for the year ended December 31, 2005. The 2006 period includes $120.1 million we invested to date in the Phase V expansion project of Jonah. The 2005 period primarily reflects $72.0 million we contributed to Deepwater Gateway to fund our share of the repayment of its construction loan in March 2005.

For additional information related to our capital spending program, see "Capital Spending" included within this Item 7.

Financing activities Cash provided by financing activities was $495.0 million for the year ended December 31, 2006 compared to $516.2 million for the year ended December 31, 2005. As a result of our capital spending program, we utilized EPO's Multi-Year Revolving Credit Facility in varying degrees throughout 2006. During 2006, we applied all or a portion of the net proceeds from equity and debt offerings to reduce debt outstanding. We used $430 million of net proceeds from our March 2006 equity offering and $260 million of net proceeds from our September 2006 equity offering to temporarily reduce amounts due under EPO's Multi-Year Revolving Credit Facility. We also used the net proceeds from the EPO's issuance of Junior Subordinated Notes A in the third quarter of 2006 to reduce debt outstanding under this facility. We used any remaining net proceeds from these offerings in 2006 for general partnership purposes.

During 2005, our EPO issued an aggregate of $1 billion in senior notes, the proceeds of which were used to repay $350.0 million due under Senior Notes A, to temporarily reduce amounts outstanding under our bank credit facilities and for general partnership purposes. Additionally, we repaid the remaining $242.2 million that was due under EPO's 364-Day Acquisition Credit Facility (which was used to finance elements of the GulfTerra Merger) using proceeds generated from our February 2005 equity offering.

Net proceeds from the issuance of our limited partner interests were $857.2 million for 2006 compared to $646.9 million for 2005. With respect to equity offerings (including sales through our distribution reinvestment program and employee unit purchase plan), we issued 34,824,649 common units 2006 versus 23,979,740 common units during 2005. Net proceeds from underwritten equity offerings were $750.8 million during 2006 reflecting the sale of 31,050,000 common units and $555.5 million during 2005 reflecting the sale of 21,250,000 common units. Our distribution reinvestment program and related employee unit purchase plan generated net proceeds of $96.9 million during 2006, including $50 million reinvested by EPCO. In comparison, this program generated proceeds of $69.7 million during 2005, including $30 million reinvested by EPCO.

Cash distributions to partners increased from $716.7 million during 2005 to $843.3 million during 2006. The year-to-year increase in cash distributions is due to an increase in common units outstanding and quarterly cash distribution rates. Cash contributions from minority interests were $27.6 million for 2006 compared to $39.1 million for 2005.

Capital Spending

An integral part of our business strategy involves expansion through business combinations, growth capital projects and investments in joint ventures. We believe that we are positioned to continue to grow our system of assets through the construction of new facilities and to capitalize on expected increases in natural gas and/or crude oil production from resource basins such as the Piceance Basin of western Colorado, the Greater Green River Basin in Wyoming, Barnett Shale in North Texas, and the deepwater Gulf of Mexico.

Management continues to analyze potential acquisitions, joint ventures and similar transactions with businesses that operate in complementary markets or geographic regions. In recent years, major oil and gas companies have sold non-strategic assets in the midstream energy sector in which we operate. We

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forecast that this trend will continue, and expect independent oil and natural gas companies to consider similar divestitures.

The following table summarizes our capital spending by activity for the periods indicated (dollars in thousands):

	For the Year Ended December 31,		
	2007	2006	2005
Capital spending for business combinations:			
Encinal acquisition, excluding non-cash consideration (1)	$ 114	$ 145,197	$ —
Piceance Basin Gathering System acquisition	368	100,000	—
South Monco Pipeline System acquisition	35,000	—	—
Canadian Enterprise Gas Products acquisition	—	17,690	—
NGL underground storage and terminalling assets purchased from Ferrellgas	—	—	145,522
Indirect interests in the Indian Springs natural gas gathering and processing assets	—	—	74,854
Additional ownership interests in Dixie Pipeline Company ("Dixie")	311	12,913	68,608
Additional ownership interests in Mid-America and Seminole pipeline systems	—	—	25,000
Other business combinations	—	700	12,618
Total	35,793	276,500	326,602
Capital spending for property, plant and equipment, net: (2)			
Growth capital projects (3)	1,986,157	1,148,123	719,372
Sustaining capital projects (4)	142,096	132,455	98,077
Total	2,128,253	1,280,578	817,449
Capital spending for intangible assets:			
Acquisition of intangible assets	11,232	—	—
Total	11,232	—	—
Capital spending attributable to unconsolidated affiliates:			
Investments in unconsolidated affiliates (5)	343,009	127,422	88,044
Total	343,009	127,422	88,044
Total capital spending	$2,518,287	$1,684,500	$1,232,095

(1) Excludes $181.1 million of non-cash consideration paid to the seller in the form of 7,115,844 of our common units. See Note 12 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for additional information regarding our business combinations.

(2) On certain of our capital projects, third parties are obligated to reimburse us for all or a portion of project expenditures. The majority of such arrangements are associated with projects related to pipeline construction and production well tie-ins. Contributions in aid of construction costs were $57.5 million, $60.5 million and $47.0 million for the years ended December 31, 2007, 2006 and 2005, respectively.

(3) Growth capital projects either result in additional revenue streams from existing assets or expand our asset base through construction of new facilities that will generate additional revenue streams.

(4) Sustaining capital expenditures are capital expenditures (as defined by GAAP) resulting from improvements to and major renewals of existing assets. Such expenditures serve to maintain existing operations but do not generate additional revenues.

(5) Fiscal 2007 includes $216.5 million in cash contributions to Cameron Highway Oil Pipeline Company ("Cameron Highway") to fund our share of the repayment of its debt obligations.

Based on information currently available, we estimate our consolidated capital spending for 2008 will approximate $1.7 billion, which includes estimated expenditures of $1.5 billion for growth capital projects and acquisitions and $0.2 billion for sustaining capital expenditures.

Our forecast of consolidated capital expenditures is based on our current strategic operating and growth plans, which are dependent upon our ability to generate the required funds from either operating cash flows or from other means, including borrowings under debt agreements, issuance of equity, and potential divestitures of certain assets to third and/or related parties. Our forecast of capital expenditures may change due to factors beyond our control, such as weather related issues, changes in supplier prices or adverse economic conditions. Furthermore, our forecast may change as a result of decisions made by management at a later date, which may include acquisitions or decisions to take on additional partners.

Our success in raising capital, including the formation of joint ventures to share costs and risks, continues to be a principal factor that determines how much capital we can invest. We believe our access to capital resources is sufficient to meet the demands of our current and future operating growth needs, and although we currently intend to make the forecasted expenditures discussed above, we may adjust the timing and amounts of projected expenditures in response to changes in capital markets.

At December 31, 2007, we had approximately $569.7 million in purchase commitments outstanding that relate to our capital spending for property, plant and equipment. These commitments primarily relate to construction of our Barnett Shale natural gas pipeline project and Meeker and Pioneer natural gas processing plants.

Significant Ongoing Growth Capital Projects

The following table summarizes information regarding our current significant growth capital projects as of February 1, 2008 (dollars in millions). The capital spending amount noted for each project at December 31, 2007 includes accrued expenditures and capitalized interest as of this date. The forecast amount noted for each project includes a provision for estimated capitalized interest.

Project Name	Estimated Date of Completion	Actual Costs Through December 31, 2007	Current Forecast Total Cost
Pioneer II natural gas processing plant	First Quarter 2008	$279.9	$360.2
Expansion of Petal natural gas storage facility	Second Quarter 2008	65.3	96.5
Meeker II natural gas processing plant	Third Quarter 2008	137.5	399.5
Sherman Extension Pipeline (Barnett Shale)	Fourth Quarter 2008	30.9	477.9
ExxonMobil Conditioning & Treating Facility — Piceance Basin	Fourth Quarter 2008	122.3	195.4
Mont Belvieu Storage Well Optimization Projects	Fourth Quarter 2008	131.0	180.5
Shenzi Oil Pipeline	2009	76.2	171.2
Marathon Piceance Basin pipeline projects	2009	3.3	114.8
Expansion of Wilson natural gas storage facility	2010	2.4	113.7

Pioneer cryogenic natural gas processing plant. In July 2006, we began construction of a cryogenic natural gas processing plant located adjacent to the silica gel plant we acquired from TEPPCO in March 2006 and subsequently expanded. The Pioneer cryogenic facility commenced operations in February 2008. This new facility has a processing capacity of 750 MMcf/d and can handle expected production growth from the Jonah and Pinedale fields located in the Greater Green River Basin in Wyoming. At full rates, the Pioneer cryogenic facility is expected to recover up to 30 MBPD of NGLs.

Expansion of Petal natural gas storage facility. We are developing a new natural gas storage cavern located on the Petal Salt Dome near Petal, Mississippi. The cavern is designed to store approximately 7.9 Bcf of natural gas, of which approximately 5.0 Bcf will be working gas capacity and 2.9 Bcf will be the base gas requirements needed to support minimum pressures. This expansion project was approved by the Federal Energy Regulatory Commission and is projected to commence operations during the second quarter of 2008. We have long-term, binding precedent agreements on the majority of the capacity.

Meeker II natural gas processing plant. In October 2007, we commenced natural gas processing operations at our Meeker I facility, which recently completed its first phase of construction. Located in Colorado's Piceance Basin, our Meeker I facility has a processing capacity of 750 MMcf/d of natural gas and is capable of extracting up to 35 MBPD of mixed NGLs. The Meeker II facility, which is under construction and expected to be completed in the third quarter of 2008, will double its processing capacity to 1.5 Bcf/d of natural gas and 70 MBPD of mixed NGLs.

Sherman Extension Pipeline (Barnett Shale). In November 2006, we announced an expansion of our Texas Intrastate System with the construction of the Sherman Extension that will transport up to 1.1 Bcf/d of natural gas from the growing Barnett Shale area of North Texas. The Sherman Extension is supported by long-term contracts with Devon Energy Corporation, the largest producer in the Barnett Shale area, and significant indications of interest from leading producers and gatherers in the Fort Worth basin, as well as other shippers on our Texas Intrastate Pipeline system. At its terminus, the new pipeline system will make deliveries into Boardwalk Pipeline Partners L.P.'s ("Boardwalk") Gulf Crossing Expansion Project, which will provide export capacity for Barnett Shale natural gas production to multiple delivery points in Louisiana, Mississippi and Alabama that offer access to attractive markets in the Northeast and Southeast United States. In addition, the Sherman Extension will provide natural gas producers in East Texas and the Waha area of West Texas with access to these higher value markets through our Texas Intrastate Pipeline system. The Sherman Extension will originate near Morgan Mill, Texas and extend through the center of the current Barnett Shale development area to Sherman, Texas.

The Barnett Shale is considered to be one of the largest unconventional natural gas resource plays in North America, covering approximately 14 counties and over seven million acres in the Fort Worth basin in North Texas. Current natural gas production is estimated at 3.4 Bcf/d from approximately 7,800 wells. Approximately 190 rigs are currently estimated to be working to develop Barnett Shale acreage in the region. According to the United States Geological Survey, the Barnett Shale has the resource potential of approximately 26 trillion cubic feet of natural gas.

ExxonMobil Conditioning & Treating Facility — Piceance Basin. In November 2006, we entered into a 30-year agreement with Exxon Mobil Corporation ("ExxonMobil") to provide gathering, compression, treating and conditioning services for natural gas produced from its Piceance Creek Development Project, which encompasses more than 29,000 acres in Rio Blanco County, Colorado. Under terms of the agreement, ExxonMobil dedicated all of its natural gas production from this development to us for processing. To provide these services, we are constructing new plant and pipeline facilities to compress the natural gas, treat it to remove impurities, extract NGLs, and deliver the gas to various pipeline transmission systems that serve the region.

Mont Belvieu Storage Well Optimization Projects. These projects are designed to improve our ability and efficiency of storing and handling NGLs and other products at our Mont Belvieu Caverns underground storage facility. These projects include new pipelines that interconnect our three storage facilities in Mont Belvieu (i.e. East, West and North locations) as well as a brine pipeline that interconnects our various above ground storage pits. Also included in this effort are several infrastructure related projects that will allow us to handle higher inbound and outbound NGL injection rates into and out of the caverns. In general this series of projects should allow us to better utilize our current asset base and allow for future growth.

Shenzi Oil Pipeline. In October 2006, we announced the execution of definitive agreements with producers to construct, own and operate an oil export pipeline that will provide firm gathering services from the BHP Billiton Plc-operated Shenzi production field located in the South Green Canyon area of the central Gulf of Mexico. The Shenzi oil export pipeline will originate at the Shenzi Field, located in 4,300 feet of water at Green Canyon Block 653, approximately 120 miles off the coast of Louisiana. The 83-mile, 20-inch diameter pipeline will have the capacity to transport up to 230 MBPD of crude oil and will connect the Shenzi Field to our Cameron Highway Oil Pipeline and Poseidon Oil Pipeline System at our Ship Shoal 332B junction platform. We own a 50% interest in the Cameron Highway Oil Pipeline and a 36% interest in the Poseidon Oil Pipeline System and operate both pipelines. The Shenzi oil export pipeline will connect to a platform being constructed by BHP Billiton Plc to develop the Shenzi Field, which is expected to begin production in mid-2009.

Marathon Piceance Basin pipeline projects. In December 2006, we entered into a long-term contract with Marathon Oil Company ("Marathon") to provide a range of midstream energy services, including natural gas gathering, compression, treating and processing, for Marathon's natural gas production in the Piceance Basin of northwest Colorado. Under the terms of the contract, we are constructing fifty miles of gathering lines to connect Marathon's multi-well drilling sites, production from which is expected to peak at approximately 180 MMcf/d, to our Piceance Creek Gathering System. From there, the natural gas will be delivered to our Meeker natural gas processing facility.

Expansion of Wilson natural gas storage facility. We are developing a new natural gas storage cavern located on the Boling Salt Dome near Boling, Texas. The cavern is designed to store approximately 7.9 Bcf of natural gas, of which approximately 5.0 Bcf will be working gas capacity and 2.9 Bcf will be the base gas requirements needed to support minimum pressures. This expansion project was approved by the Texas Railroad Commission and is projected to commence operations in 2010. We expect to secure binding precedent agreements on all capacity before the cavern commences operations.

Pipeline Integrity Costs

Our NGL, petrochemical and natural gas pipelines are subject to pipeline safety programs administered by the U.S. Department of Transportation, through its Office of Pipeline Safety. This federal agency has issued safety regulations containing requirements for the development of integrity management programs for hazardous liquid pipelines (which include NGL and petrochemical pipelines) and natural gas pipelines. In general, these regulations require companies to assess the condition of their pipelines in certain high consequence areas (as defined by the regulation) and to perform any necessary repairs.

In April 2002, a subsidiary of ours acquired several midstream energy assets located in Texas and New Mexico from El Paso Corporation ("El Paso"). These assets included the Texas Intrastate System and the Waha and Carlsbad Gathering Systems. With respect to such assets, El Paso agreed to indemnify our subsidiary for any pipeline integrity costs it incurred (whether paid or payable) for five years following the acquisition date. The indemnity provisions did not take effect until such costs exceeded $3.3 million annually; however, the amount reimbursable by El Paso was capped at $50.2 million in the aggregate. In 2007 and 2006, we recovered $31.1 million and $13.7 million, respectively from El Paso related to our 2006 and 2005 expenditures. During 2007, we received a final amount of $5.4 million from El Paso related to this indemnity.

The following table summarizes our pipeline integrity costs, net of indemnity payments from El Paso, for the periods indicated (dollars in thousands):

	For the Year Ended December 31,		
	2007	**2006**	**2005**
Expensed	$43,499	$26,397	$17,245
Capitalized	52,420	38,180	24,964
Total	$95,919	$64,577	$42,209

We expect our cash outlay for the pipeline integrity program, irrespective of whether such costs are capitalized or expensed to approximate $65 million in 2008.

Critical Accounting Policies and Estimates

In our financial reporting process, we employ methods, estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of the date of our financial statements. These methods, estimates and assumptions also affect the reported amounts of revenues and expenses during the reporting period. Investors should be aware that actual results could differ from these estimates if the underlying assumptions prove to be incorrect. The following describes the estimation risk currently underlying our most significant financial statement items:

Depreciation methods and estimated useful lives of property, plant and equipment

In general, depreciation is the systematic and rational allocation of an asset's cost, less its residual value (if any), to the periods it benefits. The majority of our property, plant and equipment is depreciated using the straight-line method, which results in depreciation expense being incurred evenly over the life of the assets. Our estimate of depreciation incorporates assumptions regarding the useful economic lives and residual values of our assets. At the time we place our assets in service, we believe such assumptions are reasonable; however, circumstances may develop that would cause us to change these assumptions, which would change our depreciation amounts prospectively.

Examples of such circumstances include:

- changes in laws and regulations that limit the estimated economic life of an asset;
- changes in technology that render an asset obsolete;
- changes in expected salvage values; or
- changes in the forecast life of applicable resource basins, if any.

At December 31, 2007 and 2006, the net book value of our property, plant and equipment was $11.59 billion and $9.83 billion, respectively. We recorded $414.9 million, $350.8 million, and $328.7 million in depreciation expense for the years ended December 31, 2007, 2006 and 2005, respectively.

For additional information regarding our property, plant and equipment, see Notes 2 and 10 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Measuring recoverability of long-lived assets and equity method investments

In general, long-lived assets (including intangible assets with finite useful lives and property, plant and equipment) are reviewed for impairment whenever events or changes in circumstances indicate that their carrying amount may not be recoverable. Examples of such events or changes might be production declines that are not replaced by new discoveries or long-term decreases in the demand or price of natural gas, oil or NGLs. Long-lived assets with recorded values that are not expected to be recovered through expected future cash flows are written-down to their estimated fair values. The carrying value of a long-lived asset is not recoverable if it exceeds the sum of undiscounted estimated cash flows expected to result from the use and eventual disposition of the existing asset. Our estimates of such undiscounted cash flows are based on a number of assumptions including anticipated operating margins and volumes; estimated useful life of the asset or asset group; and estimated salvage values. An impairment charge would be recorded for the excess of a long-lived asset's carrying value over its estimated fair value, which is based on a series of assumptions similar to those used to derive undiscounted cash flows. Those assumptions also include usage of probabilities for a range of possible outcomes, market values and replacement cost estimates.

An equity method investment is evaluated for impairment whenever events or changes in circumstances indicate that there is a possible loss in value of the investment other than a temporary decline. Examples of such events include sustained operating losses of the investee or long-term negative changes in the investee's industry. The carrying value of an equity method investment is not recoverable if it exceeds the sum of discounted estimated cash flows expected to be derived from the investment. This estimate of discounted cash flows is based on a number of assumptions including discount rates; probabilities assigned to different cash flow scenarios; anticipated margins and volumes and estimated useful life of the investment. A significant change in these underlying assumptions could result in our recording an impairment charge.

We recognized a non-cash asset impairment charge related to property, plant and equipment of $0.1 million in 2006, which is reflected as a component of operating costs and expenses. No such asset impairment charges were recorded in 2007 and 2005.

During 2007, we evaluated our equity method investment in Nemo Gathering Company, LLC for impairment. As a result of this evaluation, we recorded a $7.0 million non-cash impairment charge that is a component of equity income from unconsolidated affiliates for the year ended December 31, 2007. Similarly, during the year ended December 31, 2006, we evaluated our equity method investment in Neptune Pipeline Company, L.L.C. for impairment and recorded a $7.4 million non-cash impairment charge. We had no such impairment charges during the year ended December 31, 2005.

For additional information regarding impairment charges associated with our long-lived assets and equity method investments, see Notes 2 and 11 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Amortization methods and estimated useful lives of qualifying intangible assets

The specific, identifiable intangible assets of a business enterprise depend largely upon the nature of its operations. Potential intangible assets include intellectual property, such as technology, patents, trademarks and trade names, customer contracts and relationships, and non-compete agreements, as well as other intangible assets. The method used to value each intangible asset will vary depending upon the nature of the asset, the business in which it is utilized, and the economic returns it is generating or is expected to generate.

Our customer relationship intangible assets primarily represent the customer base we acquired in connection with business combinations and asset purchases. The value we assigned to these customer relationships is being amortized to earnings using methods that closely resemble the pattern in which the economic benefits of the underlying oil and natural gas resource bases from which the customers produce are estimated to be consumed or otherwise used. Our estimate of the useful life of each resource base is based on a number of factors, including reserve estimates, the economic viability of production and exploration activities and other industry factors.

Our contract-based intangible assets represent the rights we own arising from discrete contractual agreements, such as the long-term rights we possess under the Shell natural gas processing agreement. A contract-based intangible asset with a finite life is amortized over its estimated useful life (or term), which is the period over which the asset is expected to contribute directly or indirectly to the cash flows of an entity. Our estimates of useful life are based on a number of factors, including:

- the expected useful life of the related tangible assets (e.g., fractionation facility, pipeline, etc.);
- any legal or regulatory developments that would impact such contractual rights; and
- any contractual provisions that enable us to renew or extend such agreements.

If our underlying assumptions regarding the estimated useful life of an intangible asset change, then the amortization period for such asset would be adjusted accordingly. Additionally, if we determine that an intangible asset's unamortized cost may not be recoverable due to impairment; we may be required to reduce the carrying value and the subsequent useful life of the asset. Any such write-down of the value and unfavorable change in the useful life of an intangible asset would increase operating costs and expenses at that time.

At December 31, 2007 and 2006, the carrying value of our intangible asset portfolio was $917.0 million and $1.0 billion, respectively. We recorded $89.7 million, $88.8 million, and $88.9 million in amortization expense associated with our intangible assets for the years ended December 31, 2007, 2006 and 2005, respectively.

For additional information regarding our intangible assets, see Notes 2 and 13 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Methods we employ to measure the fair value of goodwill

Goodwill represents the excess of the purchase prices we paid for certain businesses over their respective fair values. We do not amortize goodwill; however, we test our goodwill (at the reporting unit level) for impairment during the second quarter of each fiscal year, and more frequently, if circumstances indicate it is more likely than not that the fair value of goodwill is below its carrying amount. Our goodwill testing involves the determination of a reporting unit's fair value, which is predicated on our assumptions regarding the future economic prospects of the reporting unit.

Such assumptions include:

- discrete financial forecasts for the assets contained within the reporting unit, which rely on management's estimates of operating margins and transportation volumes;
- long-term growth rates for cash flows beyond the discrete forecast period; and
- appropriate discount rates.

If the fair value of the reporting unit (including its inherent goodwill) is less than its carrying value, a charge to earnings is required to reduce the carrying value of goodwill to its implied fair value. At December 31, 2007 and 2006, the carrying value of our goodwill was $591.7 million and $590.5 million, respectively. We did not record any goodwill impairment charges during the years ended December 31, 2007, 2006 and 2005.

For additional information regarding our goodwill, see Notes 2 and 13 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Our revenue recognition policies and use of estimates for revenues and expenses

In general, we recognize revenue from our customers when all of the following criteria are met:

- persuasive evidence of an exchange arrangement exists;
- delivery has occurred or services have been rendered;
- the buyer's price is fixed or determinable; and
- collectability is reasonably assured.

We record revenue when sales contracts are settled (i.e., either physical delivery of product has taken place or the services designated in the contract have been performed). We record any necessary allowance for doubtful accounts as required by our established policy.

Our use of certain estimates for revenues and expenses has increased as a result of SEC regulations that require us to submit financial information on accelerated time frames. Such estimates are necessary due to the timing of compiling actual billing information and receiving third-party data needed to record transactions for financial reporting purposes. One example of such use of estimates is the accrual of an estimate of processing plant revenue and the cost of natural gas for a given month (prior to receiving actual customer and vendor-related plant operating information for the subject period). These estimates reverse in the following month and are offset by the corresponding actual customer billing and vendor-invoiced amounts. Accordingly, we include one month of certain estimated data in our results of operations. Such estimates are generally based on actual volume and price data through the first part of the month and estimated for the remainder of the month, adjusted accordingly for any known or expected changes in volumes or rates through the end of the month.

If the basis of our estimates proves to be substantially incorrect, it could result in material adjustments in results of operations between periods. On an ongoing basis, we review our estimates based on currently available information. Changes in facts and circumstances may result in revised estimates and could affect our reported financial statements and accompanying notes.

Reserves for environmental matters

Each of our business segments is subject to federal, state and local laws and regulations governing environmental quality and pollution control. Such laws and regulations may, in certain instances, require us to remediate current or former operating sites where specified substances have been released or disposed of. We accrue reserves for environmental matters when our assessments indicate that it is probable that a liability has been incurred and an amount can be reasonably estimated. Our assessments are based on studies, as well as site surveys, to determine the extent of any environmental damage and the necessary requirements to remediate this damage. Future environmental developments, such as increasingly strict environmental laws and additional claims for damages to property, employees and other persons resulting from current or past operations, could result in substantial additional costs beyond our current reserves.

At December 31, 2007 and 2006, we had a liability for environmental remediation of $26.5 million and $24.2 million, respectively, which was derived from a range of reasonable estimates based upon studies and site surveys. We follow the provisions of AICPA Statement of Position 96-1, which provides key guidance on recognition, measurement and disclosure of remediation liabilities. We have recorded our best estimate of the cost of remediation activities.

See Item 3 of this annual report for recent developments regarding environmental matters.

Natural gas imbalances

In the pipeline transportation business, natural gas imbalances frequently result from differences in gas volumes received from and delivered to our customers. Such differences occur when a customer delivers more or less gas into our pipelines than is physically redelivered back to them during a particular time period. The vast majority of our settlements are through in-kind arrangements whereby incremental volumes are delivered to a customer (in the case of an imbalance payable) or received from a customer (in the case of an imbalance receivable). Such in-kind deliveries are on-going and take place over several months. In some cases, settlements of imbalances accumulated over a period of time are ultimately cashed out and are generally negotiated at values which approximate average market prices over a period of time. As a result, for gas imbalances that are ultimately settled over future periods, we estimate the value of such current assets and liabilities using average market prices, which is representative of the estimated value of the imbalances upon final settlement. Changes in natural gas prices may impact our estimates.

At December 31, 2007 and 2006, our imbalance receivables, net of allowance for doubtful accounts, were $60.9 million and $97.8 million, respectively, and are reflected as a component of "Accounts and notes receivable — trade" on our balance sheets. At December 31, 2007 and 2006, our imbalance payables were $38.3 million and $51.2 million, respectively, and are reflected as a component of "Accrued gas payables" on our balance sheets.

Other Items

Initial Public Offering of Duncan Energy Partners

In September 2006, we formed a consolidated subsidiary, Duncan Energy Partners, to acquire, own and operate a diversified portfolio of midstream energy assets and to support the growth objectives of EPO. On February 5, 2007, Duncan Energy Partners completed its initial public offering of 14,950,000 common units (including an overallotment amount of 1,950,000 common units) at $21.00 per unit, which generated net proceeds to Duncan Energy Partners of $291.9 million. As consideration for assets contributed and reimbursement for capital expenditures related to these assets, Duncan Energy Partners distributed $260.6 million of these net proceeds to us along with $198.9 million in borrowings under its credit facility and a final amount of 5,351,571 common units of Duncan Energy Partners. Duncan Energy Partners used $38.5 million of net proceeds from the overallotment to redeem 1,950,000 of the 7,301,571 common units it had originally issued to Enterprise Products Partners, resulting in the final amount of 5,351,571 common units beneficially owned by Enterprise Products Partners. We used the cash received from Duncan Energy Partners to temporarily reduce amounts outstanding under EPO's Multi-Year Revolving Credit Facility.

We contributed 66% of our equity interests in the following subsidiaries to Duncan Energy Partners:

- Mont Belvieu Caverns, which owns salt dome storage caverns located in Mont Belvieu, Texas that receive, store and deliver NGLs and certain petrochemical products for industrial customers located along the upper Texas Gulf Coast, which has the largest concentration of petrochemical plants and refineries in the United States;
- Acadian Gas, which owns an onshore natural gas pipeline system that gathers, transports, stores and markets natural gas in Louisiana. The Acadian Gas system links natural gas supplies from onshore and offshore Gulf of Mexico developments (including offshore pipelines, continental shelf and deepwater production) with local gas distribution companies, electric generation plants and industrial customers, including those in the Baton Rouge-New Orleans-Mississippi River corridor. A subsidiary of Acadian Gas owns our 49.5% equity interest in Evangeline;
- Sabine Propylene, which transports polymer-grade propylene between Port Arthur, Texas and a pipeline interconnect located in Cameron Parish, Louisiana;
- Lou-Tex Propylene, which transports chemical-grade propylene from Sorrento, Louisiana to Mont Belvieu, Texas; and
- South Texas NGL, which began transporting NGLs from Corpus Christi, Texas to Mont Belvieu, Texas in January 2007. South Texas NGL owns the DEP South Texas NGL Pipeline System.

In addition to the 34% ownership interest we retained in each of these entities, we also own the 2% general partner interest in Duncan Energy Partners and 26.4% of Duncan Energy Partners' outstanding common units. Accordingly, we have in effect retained a net economic interest of approximately 52.4% in Duncan Energy Partners as of December 31, 2007. EPO directs the business operations of Duncan Energy Partners through its ownership and control of the general partner of Duncan Energy Partners.

For financial reporting purposes, we consolidate the financial statements of Duncan Energy Partners with those of our own and reflect its operations as a component of our business segments. Also, due to common control of the entities by Dan L. Duncan, the initial consolidated balance sheet of Duncan Energy Partners reflects our historical carrying basis in each of the subsidiaries contributed to Duncan Energy Partners.

The public ownership of Duncan Energy Partners' net assets and earnings are presented as a component of minority interest in our consolidated financial statements. The public owners of Duncan Energy Partners have no direct equity interests in us as a result of this transaction. The borrowings of Duncan Energy Partners are presented as part of our consolidated debt; however, we do not have any obligation for the payment of interest or repayment of borrowings incurred by Duncan Energy Partners. For additional information regarding Duncan Energy Partners, see Note 17 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

In certain cases, EPO is responsible for funding 100% of project costs rather than sharing such costs with Duncan Energy Partners in accordance with the existing sharing ratio of 66% funded by Duncan Energy Partners and 34% funded by EPO. Under the Omnibus Agreement, EPO agreed to make additional contributions to Duncan Energy Partners as reimbursement for Duncan Energy Partners' 66% share of any excess project costs above (i) the $28.6 million of estimated project costs to complete the Phase II expansions of the DEP South Texas NGL Pipeline System and (ii) $14.1 million of estimated project costs for additional Mont Belvieu brine production capacity and above-ground storage reservoir projects. These projects were in progress at the time of Duncan Energy Partners' initial public offering. In December 2007, EPO made cash contributions totaling $9.9 million to Duncan Energy Partners' subsidiaries in connection with the Omnibus Agreement.

In December 2007, EPO made an additional $38.1 million cash contribution to Mont Belvieu Caverns for capital expenditures in which Duncan Energy Partners is not a participant. This contribution was in accordance with provisions of the Mont Belvieu Caverns' limited liability company agreement, which states that when Duncan Energy Partners elects to not participate in certain projects, then EPO is responsible for funding 100% of such projects. To the extent such non-participated projects generate incremental earnings for Mont Belvieu Caverns in the future, the sharing ratio for Mont Belvieu Caverns will be adjusted to allocate such incremental cash flows to EPO. Under the terms of the agreement, Duncan Energy Partners may elect to reacquire for consideration a 66% share of these projects at a later date.

Insurance Matters

We participate as named insureds in EPCO's current insurance program, which provides us with property damage, business interruption and other coverages, which are customary for the nature and scope of our operations. EPCO attempts to place all insurance coverage with carriers having ratings of "A" or higher. However, two carriers associated with the EPCO insurance program were downgraded by Standard & Poor's during 2006. One of these carriers is currently rated at "A-" and the other, "BBB." At present, there is no indication that these two carriers would be unable to fulfill any insuring obligation. Furthermore, we currently do not have any claims which might be affected by these carriers. EPCO continues to monitor these situations. For additional information regarding our significant risks and uncertainties due to hurricanes, see Note 21 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Contractual Obligations

The following table summarizes our significant contractual obligations at December 31, 2007 (dollars in thousands).

Contractual Obligations	Total	Payment or Settlement due by Period Less than 1 year	1-3 years	3-5 years	More than 5 years
Scheduled maturities of long-term debt (1)	$ 6,896,500	$ —	$1,091,840	$1,347,160	$ 4,457,500
Estimated cash payments for interest (2)	$ 9,071,523	$ 437,686	$ 831,740	$ 676,622	$ 7,125,475
Operating lease obligations (3)	$ 325,705	$ 27,785	$ 49,172	$ 46,922	$ 201,826
Purchase obligations: (4)					
Product purchase commitments:					
Estimated payment obligations:					
Natural gas	$ 685,600	$ 137,345	$ 273,940	$ 274,315	$ —
NGLs	$ 4,041,275	$ 697,277	$ 830,264	$ 830,264	$ 1,683,470
Petrochemicals	$ 4,065,675	$1,751,152	$1,261,071	$ 375,368	$ 678,084
Other	$ 60,385	$ 31,392	$ 17,114	$ 3,831	$ 8,048
Underlying major volume commitments:					
Natural gas (in BBtus)	91,350	18,300	36,500	36,550	—
NGLs (in MBbls)	50,798	9,745	10,172	10,172	20,709
Petrochemicals (in MBbls)	45,207	20,115	13,704	4,097	7,291
Service payment commitments	$ 8,962	$ 6,745	$ 1,657	$ 186	$ 374
Capital expenditure commitments (5)	$ 569,654	$ 569,654	$ —	$ —	$ —
Other Long-Term Liabilities, as reflected in our Consolidated Balance Sheet (6)	$ 73,748	$ —	$ 23,680	$ 3,229	$ 46,839
Total	$25,799,027	$3,659,036	$4,380,478	$3,557,897	$14,201,616

(1) Represents our scheduled future maturities of consolidated debt obligations for the periods indicated. See Note 14 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding our debt obligations.

(2) Our estimated cash payments for interest are based on the principle amount of consolidated debt obligations outstanding at December 31, 2007. With respect to variable-rate debt, we applied the weighted-average interest rates paid during 2007. See Note 14 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding variable interest rates charged in 2007 under our credit agreements. In addition, our estimate of cash payments for interest gives effect to interest rate swap agreements in place at December 31, 2007. See Note 7 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report. Our estimated cash payments for interest are significantly influenced by the long-term maturities of our $550.0 million Junior Notes A (due August 2066) and $700.0 million Junior Notes B (due January 2068). Our estimated cash payments for interest assume that the Junior Note obligations are not called prior to maturity.

(3) Primarily represents operating leases for (i) underground caverns for the storage of natural gas and NGLs, (ii) leased office space with an affiliate of EPCO, (iii) a railcar unloading terminal in Mont Belvieu, Texas and (iv) land held pursuant to right-of-way agreements.

(4) Represents enforceable and legally binding agreements to purchase goods or services based on the contractual terms of each agreement at December 31, 2007.

(5) Represents our short-term unconditional payment obligations relating to our capital projects.

(6) As presented on our Consolidated Balance Sheet at December 31, 2007, other long-term liabilities consist primarily of (i) liabilities for our asset retirement obligations and (ii) liabilities for environmental remediation costs. For information regarding our environmental remediation costs and asset retirement obligations, see Notes 2 and 10 respectively, of our Notes to Consolidated Financial Statements included under Item 8 of this annual report.

For additional information regarding our significant contractual obligations involving operating leases and purchase obligations, see Note 20 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Off-Balance Sheet Arrangements

Except for the following information regarding debt obligations of certain unconsolidated affiliates, we have no off-balance sheet arrangements, as described in Item 303(a)(4)(ii) of Regulation S-K, that have or are reasonably expected to have a material current or future effect on our financial condition, revenues, expenses, results of operations, liquidity, capital expenditures or capital resources. The following information summarizes the significant terms of such unconsolidated debt obligations.

Poseidon. At December 31, 2007, Poseidon's debt obligations consisted of $91.0 million outstanding under its $150.0 million revolving credit facility. Amounts borrowed under this facility mature in May 2011 and are secured by substantially all of Poseidon's assets.

Evangeline. At December 31, 2007, Evangeline's debt obligations consisted of (i) $13.2 million in principal amount of 9.90% fixed rate Series B senior secured notes due December 2010 and (ii) a $7.5 million subordinated note payable. Enterprise Products Partners had $1.1 million of letters of credit outstanding on December 31, 2007 that were furnished on behalf of Evangeline's debt.

Summary of Related Party Transactions

The following table summarizes our related party transactions for the periods indicated (dollars in thousands).

	For the Year Ended December 31,		
	2007	2006	2005
Revenues from consolidated operations			
EPCO and affiliates	$362,076	$ 98,671	$ 311
Unconsolidated affiliates	290,640	304,559	367,204
Total	$652,716	$403,230	$367,515
Operating costs and expenses			
EPCO and affiliates	$329,699	$311,537	$293,134
Unconsolidated affiliates	32,765	31,606	23,563
Total	$362,464	$343,143	$316,697
General and administrative expenses			
EPCO and affiliates	$ 56,518	$ 41,265	$ 40,954

For additional information regarding our related party transactions, see Note 17 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report. For information regarding certain business relationships and related transactions, see Item 13 of this annual report.

We have an extensive and ongoing relationship with EPCO and its affiliates, including TEPPCO and Energy Transfer Equity. Our revenues from EPCO and affiliates are primarily associated with sales of NGL products. Our expenses with EPCO and affiliates are primarily due to (i) reimbursements we pay EPCO in connection with an administrative services agreement and (ii) purchases of NGL products. TEPPCO is an affiliate of ours due to the common control relationship of both entities. Enterprise GP Holdings acquired non-controlling ownership interests in both ETE GP and Energy Transfer Equity in May 2007. As a result of this transaction, ETE GP and Energy Transfer Equity became related parties to us.

Many of our unconsolidated affiliates perform supporting or complementary roles to our consolidated business operations. The majority of our revenues from unconsolidated affiliates relate to natural gas sales to a Louisiana affiliate. The majority of our expenses with unconsolidated affiliates pertain to payments we make to K/D/S Promix, L.L.C. for NGL transportation, storage and fractionation services.

On February 5, 2007, our consolidated subsidiary, Duncan Energy Partners, completed an underwritten initial public offering of its common units. Duncan Energy Partners was formed in September 2006 as a Delaware limited partnership to, among other things, acquire ownership interests in certain of our midstream energy businesses. For additional information regarding Duncan Energy Partners, see "Other Items — Initial Public Offering of Duncan Energy Partners" within this section.

Non-GAAP reconciliations

A reconciliation of our measurement of total non-GAAP gross operating margin to GAAP operating income and income before provision for income taxes, minority interest and the cumulative effect of changes in accounting principles follows (dollars in thousands):

	For the Year the Ended December 31,		
	2007	2006	2005
Total segment gross operating margin	$1,492,068	$1,362,449	$1,136,347
Adjustments to reconcile total gross operating margin			
To operating income:			
Depreciation, amortization and accretion in operating costs and expenses	(513,840)	(440,256)	(413,441)
Operating lease expense paid by EPCO	(2,105)	(2,109)	(2,112)
Gain (loss) on sale of assets in operating costs and expenses	(5,391)	3,359	4,488
General and administrative costs	(87,695)	(63,391)	(62,266)
Consolidated operating income	883,037	860,052	663,016
Other expense, net	(303,463)	(229,967)	(225,178)
Income before provision for income taxes, minority interest and the cumulative effect of changes in accounting principles	$ 579,574	$ 630,085	$ 437,838

EPCO subleases to us certain equipment located at our Mont Belvieu facility and 100 railcars for $1 per year (the "retained leases"). These subleases are part of the administrative services agreement that we executed with EPCO in connection with our formation in 1998. EPCO holds this equipment pursuant to operating leases for which it has retained the corresponding cash lease payment obligation. We record the full value of such lease payments made by EPCO as a non-cash related party operating expense, with the offset to partners' equity recorded as a general contribution to our partnership. Apart from the partnership interests we granted to EPCO at our formation, EPCO does not receive any additional ownership rights as a result of its contribution to us of the retained leases. For additional information regarding the administrative services agreement and the retained leases, see Item 13 of this annual report.

Cumulative effect of changes in accounting principles

Our Statements of Consolidated Operations reflect the following cumulative effects of changes in accounting principles:

- We recognized, as a benefit, a cumulative effect of a change in accounting principle of $1.5 million in 2006 based on the Statement of Financial Accounting Standards ("SFAS") 123(R), "Share-Based Payment," requirements to recognize compensation expense based upon the grant date fair value of an equity award and the application of an estimated forfeiture rate to unvested awards.

- We recorded a $4.2 million non-cash expense related to certain asset retirement obligations in 2005 due to our implementation of FIN 47 as of December 31, 2005.

For additional information regarding these changes in accounting principles, including a presentation of the pro forma effects these changes would have had on our historical earnings, see Note 8 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Recent Accounting Pronouncements

Several new accounting standards have recently been issued that will or may affect our future financial statements:

- Statement of Financial Accounting Standards ("SFAS") 157, "Fair Value Measurements;"
- SFAS 160, "Noncontrolling Interests in Consolidated Financial Statements — an amendment of ARB No. 51;" and
- SFAS 141(R), "Business Combinations."

For additional information regarding these recent accounting developments and others that may affect our future financial statements, see Note 3 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Item 7A. *Quantitative and Qualitative Disclosures About Market Risk.*

We are exposed to financial market risks, including changes in commodity prices, interest rates and foreign exchange rates. In addition, we are exposed to fluctuations in exchange rates between the U.S. dollar and Canadian dollar. We may use financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to mitigate the risks of certain identifiable and anticipated transactions. In general, the type of risks we attempt to hedge are those related to (i) the variability of future earnings, (ii) fair values of certain debt instruments and (iii) cash flows resulting from changes in applicable interest rates, commodity prices or exchange rates.

We recognize financial instruments as assets and liabilities on our Consolidated Balance Sheets based on fair value. Fair value is generally defined as the amount at which a financial instrument could be exchanged in a current transaction between willing parties, not in a forced or liquidation sale. The estimated fair values of our financial instruments have been determined using available market information and appropriate valuation techniques. We must use considerable judgment, however, in interpreting market data and developing these estimates. Accordingly, our fair value estimates are not necessarily indicative of the amounts that we could realize upon disposition of these instruments. The use of different market assumptions and/or estimation techniques could have a material effect on our estimates of fair value.

Changes in the fair value of financial instrument contracts are recognized currently in earnings unless specific hedge accounting criteria are met. If the financial instruments meet those criteria, the instrument's gains and losses offset the related results of the hedged item in earnings for a fair value hedge and are deferred in other comprehensive income for a cash flow hedge. Gains and losses related to a cash flow hedge are reclassified into earnings when the forecasted transaction affects earnings. For additional information regarding our accounting for financial instruments, see Note 7 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

To qualify as a hedge, the item to be hedged must be exposed to commodity, interest rate or exchange rate risk and the hedging instrument must reduce the exposure and meet the hedging requirements of SFAS 133, "Accounting for Derivative Instruments and Hedging Activities" (as amended and interpreted). We must formally designate the financial instrument as a hedge and document and assess the effectiveness of the hedge at inception and on a quarterly basis. Any ineffectiveness of the hedge is recorded in current earnings.

We routinely review our outstanding financial instruments in light of current market conditions. If market conditions warrant, some financial instruments may be closed out in advance of their contractual settlement dates thus realizing income or loss depending on the specific hedging criteria. When this occurs, we may enter into a new financial instrument to reestablish the hedge to which the closed instrument relates.

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Interest Rate Risk Hedging Program

Our interest rate exposure results from variable and fixed rate borrowings under various debt agreements. We manage a portion of our interest rate exposures by utilizing interest rate swaps and similar arrangements, which allow us to convert a portion of fixed rate debt into variable rate debt or a portion of variable rate debt into fixed rate debt. The following information summarizes significant components of our interest rate risk hedging portfolio:

Fair value hedges — Interest rate swaps

As summarized in the following table, we had eleven interest rate swap agreements outstanding at December 31, 2007 that were accounted for as fair value hedges.

Hedged Fixed Rate Debt	Number Of Swaps	Period Covered by Swap	Termination Date of Swap	Fixed to Variable Rate (1)	Notional Amount
Senior Notes B, 7.50% fixed rate, due Feb. 2011	1	Jan. 2004 to Feb. 2011	Feb. 2011	7.50% to 8.65%	$50 million
Senior Notes C, 6.375% fixed rate, due Feb. 2013	2	Jan. 2004 to Feb. 2013	Feb. 2013	6.38% to 7.19%	$200 million
Senior Notes G, 5.6% fixed rate, due Oct. 2014	6	4th Qtr. 2004 to Oct. 2014	Oct. 2014	5.60% to 6.13%	$600 million
Senior Notes K, 4.95% fixed rate, due June 2010	2	Aug. 2005 to June 2010	June 2010	4.95% to 5.33%	$200 million

(1) The variable rate indicated is the all-in variable rate for the current settlement period.

We have designated these interest rate swaps as fair value hedges under SFAS 133 since they mitigate changes in the fair value of the underlying fixed rate debt. As effective fair value hedges, an increase in the fair value of these interest rate swaps is equally offset by an increase in the fair value of the underlying hedged debt. The offsetting changes in fair value have no effect on current period interest expense.

These eleven agreements have a combined notional amount of $1.1 billion and match the maturity dates of the underlying debt being hedged. Under each swap agreement, we pay the counterparty a variable interest rate based on six-month London interbank offered rate ("LIBOR") (plus an applicable margin as defined in each swap agreement), and receive back from the counterparty a fixed interest rate payment based on the stated interest rate of the debt being hedged, with both payments calculated using the notional amounts stated in each swap agreement. We settle amounts receivable from or payable to the counterparties every six months (the "settlement period"). The settlement amount is amortized ratably to earnings as either an increase or a decrease in interest expense over the settlement period.

The total fair value of these eleven interest rate swaps at December 31, 2007, was an asset of $14.8 million, with an offsetting decrease in the fair value of the underlying debt. Interest expense for the years ended December 31, 2007, 2006 and 2005 reflects a $8.9 million loss, $5.2 million loss and $10.8 million benefit from these swap agreements, respectively.

The following table shows the effect of hypothetical price movements on the estimated fair value of our interest rate swap portfolio and the related change in fair value ("FV") of the underlying debt at the dates indicated (dollars in thousands). Income is not affected by changes in the fair value of these swaps; however, these swaps effectively convert the hedged portion of fixed-rate debt to variable-rate debt. As a result, interest expense (and related cash outlays for debt service) will increase or decrease with the change in the periodic "reset" rate associated with the respective swap. Typically, the reset rate is an agreed upon index rate published for the first day of the six-month interest calculation period.

Scenario	Resulting Classification	Swap Fair Value at December 31, 2006	December 31, 2007	February 12, 2008
FV assuming no change in underlying interest rates	*Asset (Liability)*	$(29,060)	$14,839	$42,544
FV assuming 10% increase in underlying interest rates	*Asset (Liability)*	(56,249)	(5,425)	24,479
FV assuming 10% decrease in underlying interest rates	*Asset (Liability)*	(1,872)	35,102	60,610

The fair value of the interest rate swaps excludes related hedged amounts we have recorded in earnings. The change in fair value between December 31, 2007 and February 12, 2008 is primarily due to a decrease in market interest rates relative to the interest rates used to determine the fair value of our financial instruments at December 31, 2007. The underlying floating LIBOR forward interest rate curve used to determine the February 12, 2008 fair values ranged from approximately 2.25% to 5.53% using 6-month reset periods ranging from February 2008 to March 2014.

Cash flow hedges — Interest Rate Swaps

Duncan Energy Partners had three interest rate swap agreements outstanding at December 31, 2007 that were accounted for as cash flow hedges.

Hedged Variable Rate Debt	Number Of Swaps	Period Covered by Swap	Termination Date of Swap	Variable to Fixed Rate(1)	Notional Value
Duncan Energy Partners' Revolver, due Feb. 2011	3	Sep. 2007 to Sep. 2010	Sep. 2010	4.84% to 4.62%	$175.0 million

(1) Amounts receivable from or payable to the swap counterparties are settled every three months (the "settlement period").

In September 2007, Duncan Energy Partners executed three floating-to-fixed interest rate swaps having a combined notional value of $175.0 million. The purpose of these financial instruments is to reduce the sensitivity of Duncan Energy Partners' earnings to variable interest rates charged under its revolving credit facility. It recognized a $0.2 million benefit from these swaps in interest expense during 2007, which includes ineffectiveness of $0.2 million (an expense) and income of $0.4 million. In 2008, Duncan Energy Partners expects to reclassify $0.7 million of accumulated other comprehensive loss that was generated by these interest rate swaps as an increase to interest expense.

At December 31, 2007, the aggregate fair value of these interest rate swaps was a liability of $3.8 million. As cash flow hedges, any increase or decrease in fair value (to the extent effective) would be recorded into other comprehensive income and amortized into income based on the settlement period hedged. Any ineffectiveness is recorded directly into earnings as an increase in interest expense. The following table shows the effect of hypothetical price movements on the estimated fair value of Duncan Energy Partners' interest rate swap portfolio (dollars in thousands).

		Swap Fair Value at	
Scenario	Resulting Classification	December 31, 2007	February 12, 2008
FV assuming no change in underlying interest rates	*Liability*	$3,782	$7,749
FV assuming 10% increase in underlying interest rates	*Liability*	2,245	6,563
FV assuming 10% decrease in underlying interest rates	*Liability*	5,319	8,934

Cash flow hedges — Treasury locks

At times, we may use treasury lock financial instruments to hedge the underlying U.S. treasury rates related to our anticipated issuances of debt. A treasury lock is a specialized agreement that fixes the price (or yield) on a specific treasury security for an established period of time. A treasury lock purchaser is protected from a rise in the yield of the underlying treasury security during the lock period. Each of the treasury lock transactions was designated as a cash flow hedge under SFAS 133.

To the extent effective, gains and losses on the value of the treasury locks will be deferred until the forecasted debt is issued and will be amortized to earnings over the life of the debt. No ineffectiveness was recognized as of December 31, 2007. Gains or losses on the termination of such instruments are amortized to earnings using the effective interest method over the estimated term of the underlying fixed-rate debt.

The following table summarizes changes in our treasury lock portfolio since December 31, 2005 (dollars in millions):

	Notional Amount	Cash Gain
Second quarter of 2006 additions to portfolio (1)	$ 250.0	$ —
Third quarter of 2006 additions to portfolio (1)	50.0	—
Third quarter of 2006 terminations (2)	(300.0)	—
Fourth quarter of 2006 additions to portfolio (3)	562.5	—
Treasury lock portfolio, December 31, 2006 (4)	562.5	—
First quarter of 2007 additions to portfolio (3)	437.5	—
Second quarter of 2007 terminations (5)	(875.0)	42.3
Third quarter of 2007 additions to portfolio (6)	875.0	—
Third quarter of 2007 terminations (7)	(750.0)	6.6
Fourth quarter of 2007 additions to portfolio (8)	350.0	—
Treasury lock portfolio, December 31, 2007 (4)	$ 600.0	$48.9

(1) EPO entered into these transactions related to its anticipated issuances of debt in 2006.

(2) Terminations relate to the issuance of the Junior Notes A ($300.0 million).

(3) EPO entered into these transactions related to its anticipated issuances of debt in 2007.

(4) The fair value of open financial instruments at December 31, 2006 and 2007 was an asset of $11.2 million and a liability of $19.6 million, respectively.

(5) Terminations relate to the issuance of the Junior Notes B ($500.0 million) and Senior Notes L ($375.0 million). Of the $42.3 million gain, $10.6 million relates to the Junior Notes B and the remainder to the Senior Notes L and its successor debt.

(6) EPO entered into these transactions related to its issuance of the Senior Notes L (including its successor debt) in August 2007 ($500.0 million) and anticipated issuance of debt during the first half of 2008 ($250.0 million)

(7) Terminations relate to the issuance of the Senior Notes L and its successor debt.

(8) EPO entered into these transactions in anticipated issuance of debt during the first half of 2008.

Commodity Risk Hedging Program

The prices of natural gas, NGLs and certain petrochemical products are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control. In order to manage the price risks associated with such products, we may enter into commodity financial instruments.

The primary purpose of our commodity risk management activities is to hedge our exposure to price risks associated with (i) natural gas purchases, (ii) the value of NGL production and inventories, (iii) related firm commitments, (iv) fluctuations in transportation revenues where the underlying fees are based on natural gas index prices and (v) certain anticipated transactions involving either natural gas, NGLs or certain petrochemical products. From time to time, we inject natural gas into storage and utilize hedging instruments to lock in the value of our inventory positions. The commodity financial instruments we utilize may be settled in cash or with another financial instrument.

The fair value of our commodity financial instrument portfolio, which primarily consisted of cash flow hedges, at December 31, 2007 was a liability of $19.3 million. During the years ended December 31, 2007, 2006 and 2005, we recorded a $28.6 million loss, $10.3 million income and $1.1 million income, respectively, related to our commodity financial instruments, which is included in operating costs and expenses on our Statements of Consolidated Operations. Included in the $28.6 million loss recorded during 2007, was ineffectiveness of $0.9 million (an expense) related to our commodity hedges. These contracts will terminate during 2008, and any amounts remaining in accumulated other comprehensive income will be recorded in earnings.

We assess the risk of our commodity financial instrument portfolio using a sensitivity analysis model. The sensitivity analysis applied to this portfolio measures the potential income or loss (i.e., the change in fair value of the portfolio) based upon a hypothetical 10% movement in the underlying quoted market prices of the commodity financial instruments outstanding at the date indicated within the following table.

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The following table shows the effect of hypothetical price movements on the estimated fair value of this portfolio at the dates presented (dollars in thousands):

Scenario	Resulting Classification	Commodity Financial Instrument Portfolio FV December 31, 2006	December 31, 2007	February 12, 2008
FV assuming no change in underlying commodity prices	*Asset (Liability)*	$ (3,184)	$ (19,305)	$ 25,941
FV assuming 10% increase in underlying commodity prices	*Asset (Liability)*	(2,119)	9,903	52,974
FV assuming 10% decrease in underlying commodity prices	*Liability*	(4,249)	(48,513)	(1,114)

The increase in portfolio fair value between December 31, 2007 and February 12, 2008 is primarily due to an increase in the price of natural gas.

Foreign Currency Hedging Program

We are exposed to foreign currency exchange rate risk through our Canadian NGL marketing subsidiary and certain construction agreements with respect to our Pioneer processing plant where payments are indexed to the Canadian dollar. As a result, we could be adversely affected by fluctuations in the foreign currency exchange rate between the U.S. dollar and the Canadian dollar. We attempt to hedge this risk using foreign exchange purchase contracts to fix the exchange rate.

Mark-to-market accounting is utilized for those foreign exchange contracts associated with our Canadian NGL marketing business. The duration of these contracts is typically one month. As of December 31, 2007, $4.7 million of these exchange contracts were outstanding, all of which settled in January 2008. In January 2008, we entered into $3.7 million of such instruments.

The foreign exchange contracts associated with our construction activities are accounted for using hedge accounting. At December 31, 2007, the fair value of these contracts was $1.3 million. These contracts settle through May 2008.

Product Purchase Commitments

We have long and short-term purchase commitments for NGLs, petrochemicals and natural gas with several suppliers. The purchase prices that we are obligated to pay under these contracts are based on market prices at the time we take delivery of the volumes. For additional information regarding these commitments, see "Contractual Obligations" included under Item 7 of this annual report.

Item 8. ***Financial Statements and Supplementary Data.***

ENTERPRISE PRODUCTS PARTNERS L.P.
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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Enterprise Products GP, LLC and
Unitholders of Enterprise Products Partners L.P.
Houston, Texas

We have audited the accompanying consolidated balance sheets of Enterprise Products Partners L.P. and subsidiaries (the "Company") as of December 31, 2007 and 2006, and the related statements of consolidated operations, consolidated comprehensive income, consolidated cash flows and consolidated partners' equity for each of the three years in the period ended December 31, 2007. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Enterprise Products Partners L.P. and subsidiaries at December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2007, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 28, 2008 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 28, 2008

ENTERPRISE PRODUCTS PARTNERS L.P.
CONSOLIDATED BALANCE SHEETS
(Dollars in thousands)

	December 31, 2007	December 31, 2006
ASSETS		
Current assets:		
Cash and cash equivalents	$ 39,722	$ 22,619
Restricted cash	53,144	23,667
Accounts and notes receivable — trade, net of allowance for doubtful accounts of $21,659 at December 31, 2007 and $23,406 at December 31, 2006	1,930,762	1,306,290
Accounts receivable — related parties	79,782	16,738
Inventories	354,282	423,844
Prepaid and other current assets	80,193	129,000
Total current assets	2,537,885	1,922,158
Property, plant and equipment, net	11,587,264	9,832,547
Investments in and advances to unconsolidated affiliates	858,339	564,559
Intangible assets, net of accumulated amortization of $341,494 at December 31, 2007 and $251,876 at December 31, 2006	917,000	1,003,955
Goodwill	591,652	590,541
Deferred tax asset	3,522	1,855
Other assets	112,345	74,103
Total assets	$16,608,007	$13,989,718
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Accounts payable — trade	$ 324,999	$ 277,070
Accounts payable — related parties	24,432	6,785
Accrued product payables	2,227,489	1,364,493
Accrued expenses	47,756	35,763
Accrued interest	130,971	90,865
Other current liabilities	289,036	209,945
Total current liabilities	3,044,683	1,984,921
Long-term debt: (see Note 14)		
Senior debt obligations — principal	5,646,500	4,779,068
Junior subordinated notes — principal	1,250,000	550,000
Other	9,645	(33,478)
Total long-term debt	6,906,145	5,295,590
Deferred tax liabilities	21,364	13,723
Other long-term liabilities	73,748	86,121
Minority interest	430,418	129,130
Commitments and contingencies		
Partners' equity:		
Limited Partners		
Common units (433,608,763 units outstanding at December 31, 2007 and 431,303,193 units outstanding at December 31, 2006)	5,976,947	6,320,577
Restricted common units (1,688,540 units outstanding at December 31, 2007 and 1,105,237 units outstanding at December 31, 2006)	15,948	9,340
General partner	122,297	129,175
Accumulated other comprehensive income	16,457	21,141
Total partners' equity	6,131,649	6,480,233
Total liabilities and partners' equity	$16,608,007	$13,989,718

See Notes to Consolidated Financial Statements.

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ENTERPRISE PRODUCTS PARTNERS L.P.
STATEMENTS OF CONSOLIDATED OPERATIONS
(Dollars in thousands, except per unit amounts)

	For Year Ended December 31, 2007	2006	2005
Revenues:			
Third parties	$16,297,409	$13,587,739	$11,889,444
Related parties	652,716	403,230	367,515
Total (see Note 16)	16,950,125	13,990,969	12,256,959
Costs and expenses:			
Operating costs and expenses			
Third parties	15,646,587	12,745,948	11,229,528
Related parties	362,464	343,143	316,697
Total operating costs and expenses	16,009,051	13,089,091	11,546,225
General and administrative costs			
Third parties	31,177	22,126	21,312
Related parties	56,518	41,265	40,954
Total general and administrative costs	87,695	63,391	62,266
Total costs and expenses	16,096,746	13,152,482	11,608,491
Equity in income of unconsolidated affiliates	29,658	21,565	14,548
Operating income	883,037	860,052	663,016
Other income (expense):			
Interest expense	(311,764)	(238,023)	(230,549)
Interest income	8,601	7,589	5,237
Other, net	(300)	467	134
Other expense	(303,463)	(229,967)	(225,178)
Income before provision for income taxes, minority interest and the cumulative effect of changes in accounting principles	579,574	630,085	437,838
Provision for income taxes	(15,257)	(21,323)	(8,362)
Income before minority interest and the cumulative effect of changes in accounting principles	564,317	608,762	429,476
Minority interest	(30,643)	(9,079)	(5,760)
Income before the cumulative effect of changes in accounting principles	533,674	599,683	423,716
Cumulative effect of changes in accounting principles (see Note 8)	—	1,472	(4,208)
Net income	$ 533,674	$ 601,155	$ 419,508
Net income allocation: (see Note 15)			
Limited partners' interest in net income	$ 417,728	$ 504,156	$ 348,512
General partner interest in net income	$ 115,946	$ 96,999	$ 70,996
Earnings per unit: (see Note 19)			
Basic and diluted income per unit before changes in accounting principles	$ 0.96	$ 1.22	$ 0.92
Basic and diluted income per unit	$ 0.96	$ 1.22	$ 0.91

See Notes to Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
STATEMENTS OF CONSOLIDATED COMPREHENSIVE INCOME
(Dollars in thousands)

	For Year Ended December 31,		
	2007	**2006**	**2005**
Net income	$533,674	$601,155	$419,508
Other comprehensive income:			
Cash flow hedges:			
Net commodity financial instrument losses during period	(17,997)	(3,622)	—
Foreign currency hedge gains	1,308	—	—
Less: Reclassification adjustment for gain included in net income related to commodity financial instruments	—	—	(1,434)
Net interest rate financial instrument gains during period	14,375	11,196	—
Less: Amortization of cash flow financing hedges	(5,429)	(4,234)	(4,048)
Total cash flow hedges	(7,743)	3,340	(5,482)
Change in funded status of Dixie benefit plans, net of tax	(52)	—	—
Foreign currency translation adjustment	2,007	(807)	—
Total other comprehensive income	(5,788)	2,533	(5,482)
Comprehensive income	$527,886	$603,688	$414,026

See Notes to Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
STATEMENTS OF CONSOLIDATED CASH FLOWS
(Dollars in thousands)

	For Year Ended December 31,		
	2007	2006	2005
Operating activities:			
Net income	$ 533,674	$ 601,155	$ 419,508
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion in operating costs and expenses	513,840	440,256	413,441
Depreciation and amortization in general and administrative costs	10,258	7,186	7,184
Amortization in interest expense	(336)	766	152
Equity in income of unconsolidated affiliates	(29,658)	(21,565)	(14,548)
Distributions received from unconsolidated affiliates	73,593	43,032	56,058
Provision for impairment of long-lived asset	—	88	—
Cumulative effect of changes in accounting principles	—	(1,472)	4,208
Operating lease expense paid by EPCO, Inc.	2,105	2,109	2,112
Minority interest	30,643	9,079	5,760
Loss (gain) on sale of assets	5,391	(3,359)	(4,488)
Deferred income tax expense	8,306	14,427	8,594
Changes in fair market value of financial instruments	981	(51)	122
Non-cash pension expense	588	—	—
Loss on early extinguishment of debt	250	—	—
Net effect of changes in operating accounts (see Note 22)	441,306	83,418	(266,395)
Net cash flows provided by operating activities	1,590,941	1,175,069	631,708
Investing activities:			
Capital expenditures	(2,185,800)	(1,341,070)	(864,453)
Contributions in aid of construction costs	57,547	60,492	47,004
Proceeds from sale of assets	12,027	3,927	44,746
Decrease (increase) in restricted cash	(47,347)	(8,715)	11,204
Cash used for business combinations (see Note 12)	(35,793)	(276,500)	(326,602)
Acquisition of intangible assets	(11,232)	—	(1,750)
Investments in unconsolidated affiliates	(332,909)	(138,266)	(87,342)
Advances from (to) unconsolidated affiliates	(10,100)	10,844	(702)
Return of investment from unconsolidated affiliate	—	—	47,500
Cash used in investing activities	(2,553,607)	(1,689,288)	(1,130,395)
Financing activities:			
Borrowings under debt agreements	6,024,518	3,378,285	4,192,345
Repayments of debt	(4,458,141)	(2,907,000)	(3,630,611)
Debt issuance costs	(16,511)	(8,955)	(9,297)
Distributions paid to partners	(957,705)	(843,292)	(716,699)
Distributions paid to minority interests	(32,326)	(8,831)	(5,724)
Contributions from Duncan Energy Partners reflected as part of minority interests (see Notes 2 and 17)	290,466	—	—
Other contributions from minority interests	12,506	27,578	39,110
Contributions from general partner related to issuance of restricted units	—	—	177
Net proceeds from issuance of common units	69,221	857,187	646,928
Repurchase of restricted units and options	(1,568)	—	—
Settlement of treasury lock contracts	48,895	—	—
Cash provided by financing activities	979,355	494,972	516,229
Effect of exchange rate changes on cash	414	(232)	—
Net change in cash and cash equivalents	16,689	(19,247)	17,542
Cash and cash equivalents, January 1	22,619	42,098	24,556
Cash and cash equivalents, December 31	$ 39,722	$ 22,619	$ 42,098

See Notes to Consolidated Financial Statements.

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ENTERPRISE PRODUCTS PARTNERS L.P.
STATEMENTS OF CONSOLIDATED PARTNERS' EQUITY
(See Note 15 for Unit History and Detail of Changes in Limited Partners' Equity)
(Dollars in thousands)

	Limited Partners	General Partner	Treasury units	Deferred Comp.	AOCI	Total
Balance, December 31, 2004	$5,217,267	$ 106,475	$(8,660)	$(10,851)	$24,554	$5,328,785
Net income	348,512	70,996	—	—	—	419,508
Operating leases paid by EPCO, Inc.	2,070	42	—	—	—	2,112
Cash distributions to partners	(630,560)	(76,752)	—	—	—	(707,312)
Unit option reimbursements to EPCO, Inc.	(9,199)	(188)	—	—	—	(9,387)
Net proceeds from sales of common units	612,616	12,502	—	—	—	625,118
Proceeds from exercise of unit options	21,374	436	—	—	—	21,810
Issuance of restricted units	9,478	177	—	(9,480)	—	175
Forfeiture of restricted units	(2,663)	(38)	—	2,361	—	(340)
Amortization of Employee Partnership awards	1,358	28	—	—	—	1,386
Amortization of deferred compensation	—	—	—	3,373	—	3,373
Cancellation of treasury units	(8,915)	(182)	8,660	—	—	(437)
Cash flow hedges	—	—	—	—	(5,482)	(5,482)
Balance, December 31, 2005	5,561,338	113,496	—	(14,597)	19,072	5,679,309
Net income	504,156	96,999	—	—	—	601,155
Operating leases paid by EPCO, Inc.	2,067	42	—	—	—	2,109
Cash distributions to partners	(739,632)	(101,805)	—	—	—	(841,437)
Unit option reimbursements to EPCO, Inc.	(1,818)	(41)	—	—	—	(1,859)
Net proceeds from sales of common units	830,825	16,943	—	—	—	847,768
Common units issued to Lewis in connection with Encinal acquisition	181,112	3,705	—	—	—	184,817
Proceeds from exercise of unit options	5,601	114	—	—	—	5,715
Change in accounting method for equity awards (see Note 8)	(15,815)	(307)	—	14,597	—	(1,525)
Change in funded status of pension and postretirement plans, net of tax	—	—	—	—	(464)	(464)
Amortization of equity awards	8,282	155	—	—	—	8,437
Foreign currency translation adjustment	—	—	—	—	(807)	(807)
Acquisition-related disbursement of cash (see Note 15)	(6,199)	(126)	—	—	—	(6,325)
Cash flow hedges	—	—	—	—	3,340	3,340
Balance, December 31, 2006	6,329,917	129,175	—	—	21,141	6,480,233
Net income	417,728	115,946	—	—	—	533,674
Operating leases paid by EPCO, Inc.	2,063	42	—	—	—	2,105
Cash distributions to partners	(833,793)	(124,388)	—	—	—	(958,181)
Unit option reimbursements to EPCO, Inc.	(2,999)	(58)	—	—	—	(3,057)
Net proceeds from sales of common units	60,445	1,232	—	—	—	61,677
Proceeds from exercise of unit options	7,549	154	—	—	—	7,703
Repurchase of restricted units and options	(1,568)	—	—	—	—	(1,568)
Change in funded status of pension and postretirement plans, net of tax	—	—	—	—	1,052	1,052
Amortization of equity awards	13,553	194	—	—	—	13,747
Foreign currency translation adjustment	—	—	—	—	2,007	2,007
Cash flow hedges	—	—	—	—	(7,743)	(7,743)
Balance, December 31, 2007	$5,992,895	$ 122,297	$ —	$ —	$16,457	$6,131,649

See Notes to Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Except per unit amounts, or as noted within the context of each footnote disclosure, the dollar amounts presented in the tabular data within these footnote disclosures are stated in thousands of dollars.

Note 1. Partnership Organization

Enterprise Products Partners L.P. is a publicly traded Delaware limited partnership, the common units of which are listed on the New York Stock Exchange ("NYSE") under the ticker symbol "EPD." Unless the context requires otherwise, references to "we," "us," "our," or "Enterprise Products Partners" are intended to mean the business and operations of Enterprise Products Partners L.P. and its consolidated subsidiaries.

We were formed in April 1998 to own and operate certain natural gas liquids ("NGLs") related businesses of EPCO, Inc. ("EPCO"). We conduct substantially all of our business through our wholly owned subsidiary, Enterprise Products Operating LLC ("EPO"), as successor in interest by merger to Enterprise Products Operating L.P. We are owned 98% by our limited partners and 2% by Enterprise Products GP, LLC (our general partner, referred to as "EPGP"). EPGP is owned 100% by Enterprise GP Holdings L.P. ("Enterprise GP Holdings"), a publicly traded affiliate, the units of which are listed on the NYSE under the ticker symbol "EPE." The general partner of Enterprise GP Holdings is EPE Holdings, LLC ("EPE Holdings"), a wholly owned subsidiary of Dan Duncan LLC, the membership interests of which are owned by Dan L. Duncan. We, EPGP, Enterprise GP Holdings, EPE Holdings and Dan Duncan LLC are affiliates and under common control of Dan L. Duncan, the Group Co-Chairman and controlling shareholder of EPCO.

References to "TEPPCO" mean TEPPCO Partners, L.P., a publicly traded affiliate, the common units of which are listed on the NYSE under the ticker symbol "TPP." References to "TEPPCO GP" refer to Texas Eastern Products Pipeline Company, LLC, which is the general partner of TEPPCO and is wholly owned by Enterprise GP Holdings.

References to "Energy Transfer Equity" mean the business and operations of Energy Transfer Equity, L.P. and its consolidated subsidiaries. References to "LE GP" mean LE GP, LLC, which is the general partner of Energy Transfer Equity. On May 7, 2007, Enterprise GP Holdings acquired non-controlling interests in both LE GP and Energy Transfer Equity.

References to "Employee Partnerships" mean EPE Unit L.P. ("EPE Unit I"), EPE Unit II, L.P. ("EPE Unit II") and EPE Unit III, L.P. ("EPE Unit III"), collectively, which are private company affiliates of EPCO, Inc. See Note 25 for information regarding the formation of Enterprise Unit L.P. in February 2008.

On February 5, 2007, a consolidated subsidiary of ours, Duncan Energy Partners L.P. ("Duncan Energy Partners"), completed an initial public offering of its common units (see Note 17). Duncan Energy Partners owns equity interests in certain of our midstream energy businesses. References to "DEP GP" mean DEP Holdings, LLC, which is the general partner of Duncan Energy Partners and is wholly owned by EPO.

For financial reporting purposes, we consolidate the financial statements of Duncan Energy Partners with those of our own and reflect its operations in our business segments. We control Duncan Energy Partners through our ownership of its general partner. Also, due to common control of the entities by Dan L. Duncan, the initial consolidated balance sheet of Duncan Energy Partners reflects our historical carrying basis in each of the subsidiaries contributed to Duncan Energy Partners. Public ownership of Duncan Energy Partners' net assets and earnings are presented as a component of minority interest in our consolidated financial statements. The borrowings of Duncan Energy Partners are presented as part of our consolidated debt; however, we do not have any obligation for the payment of interest or repayment of borrowings incurred by Duncan Energy Partners.

Note 2. Summary of Significant Accounting Policies

Allowance for Doubtful Accounts

Our allowance for doubtful accounts is determined based on specific identification and estimates of future uncollectible accounts. Our procedure for determining the allowance for doubtful accounts is based on (i) historical experience with customers, (ii) the perceived financial stability of customers based on our research, and (iii) the levels of credit we grant to customers. In addition, we may increase the allowance account in response to the specific identification of customers involved in bankruptcy proceedings and similar financial difficulties. On a routine basis, we review estimates associated with the allowance for doubtful accounts to ensure that we have recorded sufficient reserves to cover potential losses. Our allowance also includes estimates for uncollectible natural gas imbalances based on specific identification of accounts.

The following table presents the activity of our allowance for doubtful accounts for the years ended December 31, 2007, 2006 and 2005:

	For the Years Ended December 31,		
	2007	2006	2005
Balance at beginning of period	$23,406	$ 37,329	$32,773
Charges to expense	2,614	473	5,391
Acquisition-related additions and other	—	—	5,541
Deductions	(4,361)	(14,396)	(6,376)
Balance at end of period	$21,659	$ 23,406	$37,329

Cash and Cash Equivalents

Cash and cash equivalents represent unrestricted cash on hand and highly liquid investments with original maturities of less than three months from the date of purchase.

Our Statements of Consolidated Cash Flows are prepared using the indirect method. The indirect method derives net cash flows from operating activities by adjusting net income to remove (i) the effects of all deferrals of past operating cash receipts and payments, such as changes during the period in inventory, deferred income and similar transactions, (ii) the effects of all accruals of expected future operating cash receipts and cash payments, such as changes during the period in receivables and payables, (iii) the effects of all items classified as investing or financing cash flows, such as gains or losses on sale of property, plant and equipment or extinguishment of debt, and (iv) other non-cash amounts such as depreciation, amortization and changes in the fair market value of financial instruments.

Consolidation Policy

We evaluate our financial interests in business enterprises to determine if they represent variable interest entities where we are the primary beneficiary. If such criteria are met, we consolidate the financial statements of such businesses with those of our own. Our consolidated financial statements include our accounts and those of our majority-owned subsidiaries in which we have a controlling interest, after the elimination of all material intercompany accounts and transactions. We also consolidate other entities and ventures in which we possess a controlling financial interest as well as partnership interests where we are the sole general partner of the partnership.

If the entity is organized as a limited partnership or limited liability company and maintains separate ownership accounts, we account for our investment using the equity method if our ownership interest is between 3% and 50% and we exercise significant influence over the entity's operating and financial policies. For all other types of investments, we apply the equity method of accounting if our ownership interest is between 20% and 50% and we exercise significant influence over the entity's operating and financial policies. Our proportionate share of profits and losses from transactions with equity method unconsolidated affiliates are eliminated in consolidation to the extent such amounts are material and remain on our balance sheet (or those of our equity method investments) in inventory or similar accounts.

If our ownership interest in an entity does not provide us with either control or significant influence, we account for the investment using the cost method.

Contingencies

Certain conditions may exist as of the date our financial statements are issued, which may result in a loss to us but which will only be resolved when one or more future events occur or fail to occur. Our management and its legal counsel assess such contingent liabilities, and such assessment inherently involves an exercise in judgment. In assessing loss contingencies related to legal proceedings that are pending against us or unasserted claims that may result in proceedings, our management and legal counsel evaluate the perceived merits of any legal proceedings or unasserted claims as well as the perceived merits of the amount of relief sought or expected to be sought therein.

If the assessment of a contingency indicates that it is probable that a material loss has been incurred and the amount of liability can be estimated, then the estimated liability would be accrued in our financial statements. If the assessment indicates that a potentially material loss contingency is not probable but is reasonably possible, or is probable but cannot be estimated, then the nature of the contingent liability, together with an estimate of the range of possible loss (if determinable and material), is disclosed.

Loss contingencies considered remote are generally not disclosed unless they involve guarantees, in which case the guarantees would be disclosed.

Current Assets and Current Liabilities

We present, as individual captions in our consolidated balance sheets, all components of current assets and current liabilities that exceed five percent of total current assets and liabilities, respectively.

Deferred Revenues

We recognize revenues when earned (see Note 4). Amounts billed in advance of the period in which the service is rendered or product delivered are recorded as deferred revenue.

Earnings Per Unit

Earnings per unit is based on the amount of income allocated to limited partners and the weighted-average number of units outstanding during the period. See Note 19 for additional information regarding our earnings per unit.

Employee Benefit Plans

In 2005, we acquired a controlling ownership interest in Dixie Pipeline Company ("Dixie"), which resulted in Dixie becoming a consolidated subsidiary of ours. Dixie employs the personnel that operate its pipeline system and certain of these employees are eligible to participate in a defined contribution plan and pension and postretirement benefit plans.

Statement of Financial Accounting Standards ("SFAS") 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)," requires businesses to record the over-funded or under-funded status of defined benefit pension and other postretirement plans as an asset or liability at a measurement date and to recognize annual changes in the funded status of each plan through other comprehensive income. At December 31, 2006, Dixie adopted the provisions of SFAS 158. See Note 6 for additional information regarding Dixie's employee benefit plans.

Environmental Costs

Environmental costs for remediation are accrued based on estimates of known remediation requirements. Such accruals are based on management's best estimate of the ultimate cost to remediate a site and are adjusted as further information and circumstances develop. Those estimates may change substantially depending on information about the nature and extent of contamination, appropriate remediation technologies, and regulatory approvals. Ongoing environmental compliance costs are charged to expense as incurred. In accruing for environmental remediation liabilities, costs of future expenditures for environmental remediation are not discounted to their present value, unless the amount and timing of the expenditures are fixed or reliably determinable. Expenditures to mitigate or prevent future environmental contamination are capitalized.

Environmental costs and related accruals were not significant prior to the GulfTerra Merger. As a result of the merger, we assumed an environmental liability for remediation costs associated with mercury gas meters. The balance of this environmental liability was $17.2 million and $20.3 million at December 31, 2007 and 2006, respectively. At December 31, 2007 and 2006, total reserves for environmental liabilities, including those related to the mercury gas meters, were $26.5 million and $24.2 million, respectively. At December 31, 2007 and 2006, $6.3 million and $7.1 million, respectively, of these amounts are classified as current liabilities.

In February 2007, we reserved $6.5 million in cash we received from a third party to fund anticipated future environmental remediation costs. These expected costs are associated with assets acquired in connection with the GulfTerra Merger. Previously, the third party had been obligated to indemnify us for such costs. As a result of the settlement, this indemnification arrangement was terminated.

The following table presents the activity of our environmental reserves for the years ended December 31, 2007, 2006 and 2005:

	For the Years Ended December 31,		
	2007	2006	2005
Balance at beginning of period	$24,178	$22,090	$22,119
Charges to expense	375	1,105	139
Acquisition-related additions and other	6,499	8,811	—
Deductions	(4,593)	(7,828)	(168)
Balance at end of period	$26,459	$24,178	$22,090

Estimates

Preparing our consolidated financial statements in conformity with generally accepted accounting principles in the United States of America ("GAAP") requires management to make estimates and assumptions that affect reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Our actual results could differ from these estimates. On an ongoing basis, management reviews its estimates based on currently available information. Changes in facts and circumstances may result in revised estimates.

Exchange Contracts

Exchanges are contractual agreements for the movements of natural gas liquids ("NGLs") and certain petrochemical products between parties to satisfy timing and logistical needs of the parties. Net exchange volumes borrowed from us under such agreements are valued and included in accounts receivable, and net exchange volumes loaned to us under such agreements are valued and accrued as a liability in accrued product payables.

Receivables and payables arising from exchange transactions are settled with movements of products rather than with cash. When payment or receipt of monetary consideration is required for product differentials and service costs, such items are recognized in our consolidated financial statements on a net basis.

Exit and Disposal Costs

Exit and disposal costs are charges associated with an exit activity not associated with a business combination or with a disposal activity covered by SFAS 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." Examples of these costs include (i) termination benefits provided to current employees that are involuntarily terminated under the terms of a benefit arrangement that, in substance, is not an ongoing benefit arrangement or an individual deferred compensation contract, (ii) costs to terminate a contract that is not a capital lease, and (iii) costs to consolidate facilities or relocate employees. In accordance with SFAS 146, "Accounting for Costs Associated with Exit and Disposal Activities," we recognize such costs when they are incurred rather than at the date of our commitment to an exit or disposal plan.

Financial Instruments

We use financial instruments such as swaps, forward and other contracts to manage price risks associated with inventories, firm commitments, interest rates, foreign currency and certain anticipated transactions. We recognize these transactions on our balance sheet as assets and liabilities based on the instrument's fair value. Fair value is generally defined as the amount at which the financial instrument could be exchanged in a current transaction between willing parties, not in a forced or liquidation sale.

Changes in fair value of financial instrument contracts are recognized currently in earnings unless specific hedge accounting criteria are met. If the financial instrument meets the criteria of a fair value hedge, gains and losses incurred on the instrument will be recorded in earnings to offset corresponding losses and gains on the hedged item. If the financial instrument meets the criteria of a cash flow hedge, gains and losses incurred on the instrument are recorded in accumulated other comprehensive income ("AOCI"). Gains and losses on cash flow hedges are reclassified from accumulated other comprehensive income to earnings when the forecasted transaction occurs or, as appropriate, over the economic life of the underlying asset. A contract designated as a hedge of an anticipated transaction that is no longer likely to occur is immediately recognized in earnings.

To qualify as a hedge, the item to be hedged must expose us to risk and the related hedging instrument must reduce the exposure and meet the hedging requirements of SFAS 133, "Accounting for Derivative Instruments and Hedging Activities" (as amended and interpreted). We formally designate the financial instrument as a hedge and document and assess the effectiveness of the hedge at its inception and thereafter on a quarterly basis. Any hedge ineffectiveness is immediately recognized in earnings. See Note 7 for additional information regarding our financial instruments.

Foreign Currency Translation

We own a NGL marketing business located in Canada. The financial statements of this foreign subsidiary are translated into U.S. dollars from the Canadian dollar, which is the subsidiary's functional currency, using the current rate method. Its assets and liabilities are translated at the rate of exchange in effect at the balance sheet date, while revenue and expense items are translated at average rates of exchange during the reporting period. Exchange gains and losses arising from foreign currency translation adjustments are reflected as separate components of accumulated other comprehensive income in the accompanying Consolidated Balance Sheets. Our net cash flows from this Canadian subsidiary may be adversely affected by changes in foreign currency exchange rates. We attempt to hedge this currency risk (see Note 7).

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Impairment Testing for Goodwill

Our goodwill amounts are assessed for impairment (i) on a routine annual basis or (ii) when impairment indicators are present. If such indicators occur (e.g., the loss of a significant customer, economic obsolescence of plant assets, etc.), the estimated fair value of the reporting unit to which the goodwill is assigned is determined and compared to its book value. If the fair value of the reporting unit exceeds its book value including associated goodwill amounts, the goodwill is considered to be unimpaired and no impairment charge is required. If the fair value of the reporting unit is less than its book value including associated goodwill amounts, a charge to earnings is recorded to reduce the carrying value of the goodwill to its implied fair value. We have not recognized any impairment losses related to goodwill for any of the periods presented. See Note 13 for additional information regarding our goodwill.

Impairment Testing for Long-Lived Assets

Long-lived assets (including intangible assets with finite useful lives and property, plant and equipment) are reviewed for impairment when events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable.

Long-lived assets with carrying values that are not expected to be recovered through future cash flows are written-down to their estimated fair values in accordance with SFAS 144. The carrying value of a long-lived asset is deemed not recoverable if it exceeds the sum of undiscounted cash flows expected to result from the use and eventual disposition of the asset. If the asset carrying value exceeds the sum of its undiscounted cash flows, a non-cash asset impairment charge equal to the excess of the asset's carrying value over its estimated fair value is recorded. Fair value is defined as the amount at which an asset or liability could be bought or settled in an arm's-length transaction. We measure fair value using market price indicators or, in the absence of such data, appropriate valuation techniques.

We recorded a non-cash asset impairment charge of $0.1 million in 2006, which is reflected as a component of operating costs and expenses in our 2006 Statement of Consolidated Operations. No asset impairment charges were recorded in 2007 and 2005.

Impairment Testing for Unconsolidated Affiliates

We evaluate our equity method investments for impairment when events or changes in circumstances indicate that there is a loss in value of the investment attributable to an other than temporary decline. Examples of such events or changes in circumstances include continuing operating losses of the entity and/or long-term negative changes in the entity's industry. In the event we determine that the loss in value of an investment is other than a temporary decline, we record a charge to earnings to adjust the carrying value of the investment to its estimated fair value.

During 2007, we evaluated our equity method investment in Nemo Gathering Company, LLC for impairment. As a result of this evaluation, we recorded a $7.0 million non-cash impairment charge that is a component of equity income from unconsolidated affiliates for the year ended December 31, 2007. Similarly, during 2006, we evaluated our investment in Neptune Pipeline Company, L.L.C. ("Neptune") for impairment. As a result of this evaluation, we recorded a $7.4 million non-cash impairment charge that is a component of equity income from unconsolidated affiliates for the year ended December 31, 2006. We had no such impairment charges during the year ended December 31, 2005. See Note 11 for additional information regarding our equity method investments.

Income Taxes

Provision for income taxes is primarily applicable to our state tax obligations under the Revised Texas Franchise Tax ("the Revised Texas Franchise Tax") and certain federal and state tax obligations of Seminole Pipeline Company ("Seminole") and Dixie, both of which are consolidated subsidiaries of ours. Deferred income tax assets and liabilities are recognized for temporary differences between the assets and liabilities of our tax paying entities for financial reporting and tax purposes.

In general, legal entities that conduct business in Texas are subject to the Revised Texas Franchise Tax. In May 2006, the State of Texas expanded its pre-existing franchise tax to include limited partnerships, limited liability companies, corporations and limited liability partnerships. As a result of the change in tax law, our tax status in the State of Texas has changed from non-taxable to taxable.

Since we are structured as a pass-through entity, we are not subject to federal income taxes. As a result, our partners are individually responsible for paying federal income taxes on their share of our taxable income. Since we do not have access to information regarding each partner's tax basis, we cannot readily determine the total difference in the basis of our net assets for financial and tax reporting purposes.

In accordance with Financial Accounting Standards Board Interpretation ("FIN") 48, "Accounting for Uncertainty in Income Taxes," we must recognize the tax effects of any uncertain tax positions we may adopt, if the position taken by us is more likely than not sustainable. If a tax position meets such criteria, the tax effect to be recognized by us would be the largest amount of benefit with more than a 50% chance of being realized upon settlement. This guidance was effective January 1, 2007, and our adoption of this guidance had no material impact on our financial position, results of operations or cash flows. See Note 18 for additional information regarding our income taxes.

Inventories

Inventories primarily consist of NGLs, certain petrochemical products and natural gas volumes that are valued at the lower of average cost or market. We capitalize, as a cost of inventory, shipping and handling charges directly related to volumes we purchase from third parties or take title to in connection with processing or other agreements. As these volumes are sold and delivered out of inventory, the average cost of these products (including freight-in charges that have been capitalized) are charged to operating costs and expenses. Shipping and handling fees associated with products we sell and deliver to customers are charged to operating costs and expenses as incurred. See Note 9 for additional information regarding our inventories.

Minority Interest

As presented in our Consolidated Balance Sheets, minority interest represents third-party ownership interests in the net assets of our consolidated subsidiaries. For financial reporting purposes, the assets and liabilities of our majority owned subsidiaries are consolidated with those of our own, with any third-party ownership in such amounts presented as minority interest. Effective February 1, 2007, the public owners of Duncan Energy Partners' common units are presented as a minority interest in our consolidated financial statements.

Minority interest, as reflected on our December 31, 2007 balance sheet, consists of $288.6 million attributable to third party owners of Duncan Energy Partners and the remainder to our other consolidated affiliates.

Minority interest expense for the year ended December 31, 2007 includes $13.9 million attributable to third party owners of Duncan Energy Partners. The remaining minority interest expense amounts for 2007 and likewise those for 2006 are attributable to our other consolidated affiliates.

Contributions from minority interests for the year ended December 31, 2007 includes $290.5 million received from third parties in connection with the initial public offering of Duncan Energy Partners in February 2007.

Natural Gas Imbalances

In the natural gas pipeline transportation business, imbalances frequently result from differences in natural gas volumes received from and delivered to our customers. Such differences occur when a customer delivers more or less gas into our pipelines than is physically redelivered back to them during a particular time period. We have various fee-based agreements with customers to transport their natural gas through our pipelines. Our customers retain ownership of their natural gas shipped through our pipelines. As such, our pipeline transportation activities are not intended to create physical volume differences that would result in significant accounting or economic events for either our customers or us during the course of the arrangement.

We settle pipeline gas imbalances through either (i) physical delivery of in-kind gas or (ii) in cash. These settlements follow contractual guidelines or common industry practices. As imbalances occur, they may be settled (i) on a monthly basis, (ii) at the end of the agreement or (iii) in accordance with industry practice, including negotiated settlements. Certain of our natural gas pipelines have a regulated tariff rate mechanism requiring customer imbalance settlements each month at current market prices.

However, the vast majority of our settlements are through in-kind arrangements whereby incremental volumes are delivered to a customer (in the case of an imbalance payable) or received from a customer (in the case of an imbalance receivable). Such in-kind deliveries are on-going and take place over several periods. In some cases, settlements of imbalances built up over a period of time are ultimately cashed out and are generally negotiated at values which approximate average market prices over a period of time. For those gas imbalances that are ultimately settled over future periods, we estimate the value of such current assets and liabilities using average market prices, which is representative of the estimated value of the imbalances upon final settlement. Changes in natural gas prices may impact our estimates.

At December 31, 2007 and 2006, our natural gas imbalance receivables, net of allowance for doubtful accounts, were $60.9 million and $97.8 million, respectively, and are reflected as a component of "Accounts and notes receivable — trade" on our Consolidated Balance Sheets. At December 31, 2007 and 2006, our imbalance payables were $38.3 million and $51.2 million, respectively, and are reflected as a component of "Accrued product payables" on our Consolidated Balance Sheets.

Property, Plant and Equipment

Property, plant and equipment is recorded at cost. Expenditures for additions, improvements and other enhancements to property, plant and equipment are capitalized and minor replacements, maintenance, and repairs that do not extend asset life or add value are charged to expense as incurred. When property, plant and equipment assets are retired or otherwise disposed of, the related cost and accumulated depreciation is removed from the accounts and any resulting gain or loss is included in the results of operations for the respective period. For financial statement purposes, depreciation is recorded based on the estimated useful lives of the related assets primarily using the straight-line method. Where appropriate, we use other depreciation methods (generally accelerated) for tax purposes. See Note 10 for additional information regarding our property, plant and equipment.

Certain of our plant operations entail periodic planned outages for major maintenance activities. These planned shutdowns typically result in significant expenditures, which are principally comprised of amounts paid to third parties for materials, contract services and related items. We use the expense-as-incurred method for our planned major maintenance activities that benefit periods in excess of one year or for periods that are not determinable. We use the deferral method for our annual planned major maintenance activities.

Asset retirement obligations ("AROs") are legal obligations associated with the retirement of tangible long-lived assets that result from their acquisition, construction, development and/or normal operation. When an ARO is incurred, we record a liability for the ARO and capitalize an equal amount as an increase in the carrying value of the related long-lived asset. Over time, the liability is accreted to its present value (accretion expense) and the capitalized amount is depreciated over the remaining useful life of the related long-lived asset. To the extent we do not settle an ARO liability at our recorded amounts, we will incur a gain or loss.

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Reclassifications

A reclassification was made to the Statements of Operations for the year ended December 31, 2005 to consistently reflect our 2005 revenues due to a reclassification of $12.7 million from "Third-parties" to "Related-parties" attributable to our Onshore Natural Gas Pipelines & Services business segment. Such reclassification related to the presentation of our 49.5% equity method investment in Evangeline Gas Pipeline Company, L.P. and Evangeline Gas Corp. (collectively "Evangeline") which revised its disclosures. A reclassification was made to the Statements of Consolidated Comprehensive Income for the year ended December 31, 2006 to include $2.2 million in reclassification adjustments for losses included in net income related to financial instruments and $8.7 million in net interest rate financial instrument gains to conform to the current year presentation of such activities.

Restricted Cash

Restricted cash represents amounts held by (i) a brokerage firm in connection with our commodity financial instruments portfolio and physical natural gas purchases made on the New York Mercantile Exchange ("NYMEX") exchange, and (ii) us for the future settlement of current liabilities we assumed in connection with our acquisition of a Canadian affiliate in October 2006.

Revenue Recognition

See Note 4 for information regarding our revenue recognition policies.

Start-Up and Organization Costs

Start-up costs and organization costs are expensed as incurred. Start-up costs are defined as one-time activities related to opening a new facility, introducing a new product or service, conducting activities in a new territory, pursuing a new class of customer, initiating a new process in an existing facility, or some new operation. Routine ongoing efforts to improve existing facilities, products or services are not considered start-up costs. Organization costs include legal fees, promotional costs and similar charges incurred in connection with the formation of a business.

Unit-Based Awards

We account for unit-based awards in accordance with SFAS 123(R), "Share-Based Payment." Prior to January 1, 2006, our unit-based awards were accounted for using the intrinsic value method described in Accounting Principles Board Opinion ("APB") 25, "Accounting for Stock Issued to Employees." The following table discloses the pro forma effect of unit-based compensation amounts on our net income and earnings per unit for the year ended December 31, 2005 as if we had applied the provisions of SFAS 123(R) instead of APB 25. The effects of applying SFAS 123(R) in the following pro forma disclosures may not be indicative of future amounts as additional awards in future years are anticipated. No pro forma adjustments are required for restricted unit awards in 2005 since compensation expense related to these awards was based on their estimated fair values. See Note 5 for additional information regarding our unit-based awards.

Reported net income	$ 419,508
Additional unit option-based compensation expense estimated using fair value-based method	(708)
Reduction in compensation expense related to Employee Partnership equity awards	1,271
Pro forma net income	$ 420,071
Basic and diluted earnings per unit:	
As reported	$ 0.91
Pro forma	$ 0.91

Note 3. Recent Accounting Developments

The following information summarizes recently issued accounting guidance that will or may affect our future financial statements:

SFAS 157

SFAS 157, "Fair Value Measurements," defines fair value, establishes a framework for measuring fair value in GAAP and expands disclosures about fair value measurements. SFAS 157 applies only to fair-value measurements that are already required (or permitted) by other accounting standards and is expected to increase the consistency of those measurements. SFAS 157 emphasizes that fair value is a market-based measurement that should be determined based on the assumptions that market participants would use in pricing an asset or liability. Companies will be required to disclose the extent to which fair value is used to measure assets and liabilities, the inputs used to develop such measurements, and the effect of certain of the measurements on earnings (or changes in net assets) during a period.

Certain requirements of SFAS 157 are effective for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. The effective date for other requirements of SFAS 157 has been deferred for one year. We adopted the provisions of SFAS 157 which are effective for fiscal years beginning after November 15, 2007 and there was no impact on our financial statements. Management is currently evaluating the impact that the deferred provisions of SFAS 157 will have on the disclosures in our financial statements in 2009.

SFAS 141(R)

SFAS 141(R), "Business Combinations," replaces SFAS 141, "Business Combinations." SFAS 141(R) retains the fundamental requirements of SFAS 141 that the acquisition method of accounting (previously termed the "purchase method") be used for all business combinations and for an acquirer to be identified for each business combination. SFAS 141(R) defines the acquirer as the entity that obtains control of one or more businesses in a business combination and establishes the acquisition date as the date that the acquirer achieves control. This new guidance also retains guidance in SFAS 141 for identifying and recognizing intangible assets separately from goodwill.

The objective of SFAS 141(R) is to improve the relevance, representational faithfulness, and comparability of the information a reporting entity provides in its financial reports about business combinations and their effects. To accomplish this, SFAS 141(R) establishes principles and requirements for how the acquirer:

- Recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interests in the acquiree.
- Recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase. SFAS 141(R) defines a bargain purchase as a business combination in which the total acquisition-date fair value of the identifiable net assets acquired exceeds the fair value of the consideration transferred plus any noncontrolling interest in the acquiree, and requires the acquirer to recognize that excess in earnings as a gain attributable to the acquirer.
- Determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination.

SFAS 141(R) also requires that direct costs of an acquisition (e.g. finder’s fees, outside consultants, etc.) be expensed as incurred and not capitalized as part of the purchase price.

As a calendar year-end entity, we will adopt SFAS 141(R) on January 1, 2009. Although we are still evaluating this new guidance, we expect that it will have an impact on the way in which we evaluate acquisitions. For example, we have made several acquisitions in the past where the fair value of assets acquired and liabilities assumed was in excess of the purchase price. In those cases, a bargain purchase would have been recognized under SFAS 141(R). Conversely, we will no longer capitalize transaction fees and other direct costs.

SFAS 160

SFAS 160, "Noncontrolling Interests in Consolidated Financial Statements — an amendment of ARB No. 51," establishes accounting and reporting standards for non-controlling interests, which have been referred to as minority interests in prior accounting literature. A noncontrolling interest is the portion of equity in a subsidiary not attributable, directly or indirectly, to a parent company. This new standard requires, among other things, that (i) ownership interests of noncontrolling interests be presented as a component of equity on the balance sheet (i.e. elimination of the mezzanine "minority interest" category); (ii) elimination of minority interest expense as a line item on the statement of income and, as a result, that net income be allocated between the parent and noncontrolling interests on the face of the statement of income; and (iii) enhanced disclosures regarding noncontrolling interests. As a calendar year-end entity, we will adopt SFAS 160 on January 1, 2009 and apply its presentation and disclosure requirements retrospectively.

Note 4. Revenue Recognition

In general, we recognize revenue from our customers when all of the following criteria are met: (i) persuasive evidence of an exchange arrangement exists, (ii) delivery has occurred or services have been rendered, (iii) the buyer’s price is fixed or determinable and (iv) collectability is reasonably assured. The following information provides a general description our underlying revenue recognition policies by business segment:

NGL Pipelines & Services

This aspect of our business generates revenues primarily from the provision of natural gas processing, NGL pipeline transportation, product storage and NGL fractionation services and the sale of NGLs. In our natural gas processing activities, we enter into margin-band contracts, percent-of-liquids contracts, percent-of-proceeds contracts, fee-based contracts, hybrid-contracts (i.e. mixed percent-of-liquids and fee-based) and keepwhole contracts. Under margin-band and keepwhole contracts, we take ownership of mixed NGLs extracted from the producer’s natural gas stream and recognize revenue when the extracted NGLs are delivered and sold to customers under NGL marketing sales contracts. In the same way, revenue is recognized under our percent-of-liquids contracts except that the volume of NGLs we extract and sell is less than the total amount of NGLs extracted from the producers’ natural gas. Under a percent-of-liquids contract, the producer retains title to the remaining percentage of mixed NGLs we extract. Under a percent-of-proceeds contract, we share in the proceeds generated from the sale of the mixed NGLs we extract on the producer’s behalf. If a cash fee for natural gas processing services is stipulated by the contract, we record revenue when the natural gas has been processed and delivered to the producer.

Our NGL marketing activities generate revenues from the sale of NGLs obtained from either our natural gas processing activities or purchased from third parties on the open market. Revenues from these sales contracts are recognized when the NGLs are delivered to customers. In general, the sales prices referenced in these contracts are market-related and can include pricing differentials for such factors as delivery location.

Under our NGL pipeline transportation contracts and tariffs, revenue is recognized when volumes have been delivered to customers. Revenue from these contracts and tariffs is generally based upon a fixed fee per gallon of liquids transported multiplied by the volume delivered. Transportation fees charged under these arrangements are either contractual or regulated by governmental agencies such as the Federal Energy Regulatory Commission ("FERC").

We collect storage revenues under our NGL and related product storage contracts based on the number of days a customer has volumes in storage multiplied by a storage rate (as defined in each contract). Under these contracts, revenue is recognized ratably over the length of the storage period. With respect to capacity reservation agreements, we collect a fee for reserving storage capacity for customers in our underground storage wells. Under these agreements, revenue is recognized ratably over the specified reservation period. Excess storage fees are collected when customers exceed their reservation amounts and are recognized in the period of occurrence.

Revenues from product terminalling activities (applicable to our import and export operations) are recorded in the period such services are provided. Customers are typically billed a fee per unit of volume loaded or unloaded. With respect to export operations, revenues may also include demand payments charged to customers who reserve the use of our export facilities and later fail to use them. Demand fee revenues are recognized when the customer fails to utilize the specified export facility as required by contract.

We enter into fee-based arrangements and percent-of-liquids contracts for the NGL fractionation services we provide to customers. Under such fee-based arrangements, revenue is recognized in the period services are provided. Such fee-based arrangements typically include a base-processing fee (typically in cents per gallon) that is subject to adjustment for changes in certain fractionation expenses (e.g. natural gas fuel costs). Certain of our NGL fractionation facilities generate revenues using percent-of-liquids contracts. Such contracts allow us to retain a contractually determined percentage of the customer's fractionated NGL products as payment for services rendered. Revenue is recognized from such arrangements when we sell and deliver the retained NGLs to customers.

Onshore Natural Gas Pipelines & Services

This aspect of our business generates revenues primarily from the provision of natural gas pipeline transportation and gathering services; natural gas storage services; and from the sale of natural gas. Certain of our onshore natural gas pipelines generate revenues from transportation and gathering agreements as customers are billed a fee per unit of volume multiplied by the volume delivered or gathered. Fees charged under these arrangements are either contractual or regulated by governmental agencies such as the FERC. Revenues associated with these fee-based contracts are recognized when volumes have been delivered.

Revenues from natural gas storage contracts typically have two components: (i) a monthly demand payment, which is associated with storage capacity reservations, and (ii) a storage fee per unit of volume held at each location. Revenues from demand payments are recognized during the period the customer reserves capacity. Revenues from storage fees are recognized in the period the services are provided.

Our natural gas marketing activities generate revenues from the sale of natural gas purchased from third parties on the open market. Revenues from these sales contracts are recognized when the natural gas is delivered to customers. In general, the sales prices referenced in these contracts are market-related and can include pricing differentials for such factors as delivery location.

Offshore Pipelines & Services

This aspect of our business generates revenues from the provision of offshore natural gas and crude oil pipeline transportation services and related offshore platform operations. Our offshore natural gas pipelines generate revenues through fee-based contracts or tariffs where revenues are equal to the product of a fee per unit of volume (typically in MMBtus) multiplied by the volume of natural gas transported. Revenues associated with these fee-based contracts and tariffs are recognized when natural gas volumes have been delivered.

The majority of our revenues from offshore crude oil pipelines are derived from purchase and sale arrangements whereby crude oil is purchased from shippers at various receipt points along the pipeline for an index-based price (less a price differential) and sold back to the shippers at various redelivery points at the same index-based price. Net revenue recognized from such arrangements is based on the price differential per unit of volume (typically in barrels) multiplied by the volume delivered. In addition, certain offshore crude oil pipelines generate revenues based upon a gathering fee per unit of volume (typically in barrels) multiplied by the volume delivered to the customer. Revenues from both arrangements are recognized when the crude oil is delivered.

Revenues from offshore platform services generally consist of demand payments and commodity charges. Revenues from platform services are recognized in the period the services are provided. Demand fees represent charges to customers served by our offshore platforms regardless of the volume the customer delivers to the platform. Revenues from commodity charges are based on a fixed-fee per unit of volume delivered to the platform (typically per MMcf of natural gas or per barrel of crude oil) multiplied by the total volume of each product delivered. Contracts for platform services often include both demand payments and commodity charges, but demand payments generally expire after a contractually fixed period of time and in some instances may be subject to cancellation by customers. Our Independence Hub and Marco Polo offshore platforms earn a significant amount of demand revenues. The Independence Hub platform will earn $55.2 million of demand revenues annually through March 2012. The Marco Polo platform will earn $25.2 million of demand revenues annually through April 2009.

Petrochemical Services

This aspect of our business generates revenues from the provision of isomerization and propylene fractionation services and the sale of certain petrochemical products. Our isomerization and propylene fractionation operations generate revenues through fee-based arrangements, which typically include a base-processing fee per gallon (or other unit of measurement) subject to adjustment for changes in natural gas, electricity and labor costs, which are the primary costs of propylene fractionation and isomerization operations. Revenues resulting from such agreements are recognized in the period the services are provided.

Our petrochemical marketing activities generate revenues from the sale of propylene and other petrochemicals obtained from either its processing activities or purchased from third parties on the open market. Revenues from these sales contracts are recognized when the petrochemicals are delivered to customers. In general, the sales prices referenced in these contracts are market-related and can include pricing differentials for such factors as delivery location.

Note 5. Accounting for Unit-Based Awards

Since January 1, 2006, we account for unit-based awards in accordance with SFAS 123(R) (see Note 2). The following table summarizes our unit-based compensation amounts by plan during each of the periods indicated:

	For the Years Ended December 31,		
	2007	2006	2005
EPCO 1998 Long-Term Incentive Plan ("1998 Plan")			
Unit options	$ 4,447	$ 701	$ —
Restricted units	7,721	5,019	3,776
Total 1998 Plan (1)	12,168	5,720	3,776
Employee Partnerships	3,911	2,146	2,043
DEP Holdings, LLC Unit Appreciation Rights	69	—	—
Total consolidated expense	$ 16,148	$ 7,866	$ 5,819

(1) Amounts for the year ended December 31, 2007 include $4.6 million associated with the resignation of our former chief executive officer.

See Note 25 for information regarding the formation of the Enterprise Products 2008 Long-Term Incentive Plan in January 2008 and Enterprise Unit L.P. in February 2008.

SFAS 123(R) requires us to recognize compensation expense related to unit-based awards based on the fair value of the award at grant date. The fair value of restricted unit awards (i.e. time-vested units under SFAS 123(R)) is based on the market price of the underlying common units on the date of grant. The fair value of other unit-based awards is estimated using the Black-Scholes option pricing model. Under

SFAS 123(R), the fair value of an equity-classified award (such as a restricted unit award) is amortized to earnings on a straight-line basis over the requisite service or vesting period. Compensation expense for liability-classified awards (such as unit appreciation rights ("UARs")) is recognized over the requisite service or vesting period of an award based on the fair value of the award remeasured at each reporting period. Liability-type awards are cash settled upon vesting.

As used in the context of the EPCO plans, the term "restricted unit" represents a time-vested unit under SFAS 123(R). Such awards are non-vested until the required service period expires.

Upon our adoption of SFAS 123(R), we recognized, as a benefit, a cumulative effect of a change in accounting principle of $1.5 million based on the SFAS 123(R) requirement to recognize compensation expense based upon the grant date fair value of an equity award and the application of an estimated forfeiture rate to unvested awards. In addition, previously recognized deferred compensation expense of $14.6 million related to our restricted common units was reversed on January 1, 2006.

Prior to our adoption of SFAS 123(R), we did not recognize any compensation expense related to unit options; however, compensation expense was recognized in connection with awards granted by EPE Unit L.P. ("EPE Unit I") and the issuance of restricted units. The effects of applying SFAS 123(R) during the year ended December 31, 2006 did not have a material effect on our net income or basic and diluted earnings per unit. Since we adopted SFAS 123(R) using the modified prospective method, we have not restated the financial statements of prior periods to reflect this new standard.

1998 Plan

Unit option awards. Under the 1998 Plan, non-qualified incentive options to purchase a fixed number of our common units may be granted to EPCO’s key employees who perform management, administrative or operational functions for us. When issued, the exercise price of each option grant is equivalent to the market price of the underlying equity on the date of grant. In general, options granted under the 1998 Plan have a cliff vesting period of four years and remain exercisable for ten years from the date of grant.

In order to fund its obligations under the 1998 Plan, EPCO may purchase common units at fair value either in the open market or directly from us. When employees exercise unit options, we reimburse EPCO for the cash difference between the strike price paid by the employee and the actual purchase price paid by EPCO for the units issued to the employee.

The fair value of each unit option is estimated on the date of grant using the Black-Scholes option pricing model, which incorporates various assumptions including expected life of the options, risk-free interest rates, expected distribution yield on our common units, and expected unit price volatility of our common units. In general, our assumption of expected life of the options represents the period of time that the options are expected to be outstanding based on an analysis of historical option activity. Our selection of the risk-free interest rate is based on published yields for U.S. government securities with comparable terms. The expected distribution yield and unit price volatility is estimated based on several factors, which include an analysis of our historical unit price volatility and distribution yield over a period equal to the expected life of the option.

The 1998 Plan provides for the issuance of up to 7,000,000 of our common units. After giving effect to outstanding option awards at December 31, 2007 and the issuance and forfeiture of restricted unit awards through December 31, 2007, a total of 1,282,256 additional common units could be issued under the 1998 Plan.

The following table presents option activity under the 1998 Plan for the periods indicated:

	Number of Units	Weighted-average strike price (dollars/unit)	Weighted-average remaining contractual term (in years)	Aggregate Intrinsic Value (1)
Outstanding at December 31, 2004	2,463,000	$18.84		
Granted (2)	530,000	26.49		
Exercised	(826,000)	14.77		
Forfeited	(85,000)	24.73		
Outstanding at December 31, 2005	2,082,000	22.16		
Granted (3)	590,000	24.85		
Exercised	(211,000)	15.95		
Forfeited	(45,000)	24.28		
Outstanding at December 31, 2006	2,416,000	23.32		
Granted (4)	895,000	30.63		
Exercised	(256,000)	19.26		
Settled or forfeited (5)	(740,000)	24.62		
Outstanding at December 31, 2007 (6)	2,315,000	26.18	7.73	$3,291
Options exercisable at:				
December 31, 2005	727,000	$19.19	5.54	$3,503
December 31, 2006	591,000	$20.85	5.11	$4,808
December 31, 2007 (6)	335,000	$22.06	3.96	$3,291

(1) Aggregate intrinsic value reflects fully vested unit options at the date indicated.

(2) The total grant date fair value of these awards was $0.7 million based on the following assumptions: (i) weighted-average expected life of options of seven years; (ii) weighted-average risk-free interest rate of 4.2%; (iii) weighted-average expected distribution yield on our common units of 9.2%; and (iv) weighted-average expected unit price volatility on our common units of 20.0%.

(3) The total grant date fair value of these awards was $1.2 million based on the following assumptions: (i) weighted-average expected life of options of seven years; (ii) weighted-average risk-free interest rate of 5.0%; (iii) weighted-average expected distribution yield on our common units of 8.9%; and (iv) weighted-average expected unit price volatility on our common units of 23.5%.

(4) The total grant date fair value of these awards was $2.4 million based on the following assumptions: (i) expected life of options of seven years; (ii) weighted-average risk-free interest rate of 4.8%; (iii) weighted-average expected distribution yield on our common units of 8.4%; and (iv) weighted-average expected unit price volatility on our common units of 23.2%.

(5) Includes the settlement of 710,000 options in connection with the resignation of our former chief executive officer.

(6) We were committed to issue 2,315,000 and 2,416,000 of our common units at December 31, 2007 and 2006, respectively, if all outstanding options awarded under the 1998 Plan (as of these dates) were exercised. An additional 285,000, 380,000, 510,000 and 805,000 of these options are exercisable in 2008, 2009, 2010 and 2011, respectively.

The total intrinsic value of option awards exercised during the years ended December 31, 2007, 2006 and 2005 were $3.0 million, $2.2 million and $9.2 million, respectively. At December 31, 2007, there was an estimated $2.8 million of total unrecognized compensation cost related to nonvested option awards granted under the 1998 Plan. We expect to recognize this amount over a weighted-average period of 3.0 years. We will recognize our share of these costs in accordance with the EPCO administrative services agreement (see Note 17).

During the years ended December 31, 2007 and 2006, we received cash of $7.5 million and $5.6 million, respectively from the exercise of option awards granted under the 1998 Plan. Conversely, our option-related reimbursements to EPCO were $3.0 million and $1.8 million, respectively.

Restricted unit awards. Under the 1998 Plan, we may also issue restricted common units to key employees of EPCO and directors of our general partner. In general, the restricted unit awards allow recipients to acquire the underlying common units at no cost to the recipient once a defined cliff vesting period expires, subject to certain forfeiture provisions. The restrictions on such units generally lapse four years from the date of grant. Compensation expense is recognized on a straight-line basis over the vesting period. Fair value of such restricted units is based on the market price of the underlying common units on the date of grant and an allowance for estimated forfeitures.

Each recipient is also entitled to cash distributions equal to the product of the number of restricted units outstanding for the participant and the cash distribution per unit paid by us to our unitholders. Since restricted units are issued securities, such distributions are reflected as a component of cash distributions to partners as shown on our statements of consolidated cash flows. We paid $2.6 million, $1.6 million and $0.9 million in cash distributions with respect to restricted units during the years ended December 31, 2007, 2006 and 2005, respectively.

The following table summarizes information regarding our restricted unit awards for the periods indicated:

	Number of Units	Weighted-Average Grant Date Fair Value per Unit(1)
Restricted units at December 31, 2004	488,525	
Granted (2)	362,011	$26.43
Vested	(6,484)	$22.00
Forfeited	(92,448)	$24.03
Restricted units at December 31, 2005	751,604	
Granted (3)	466,400	$25.21
Vested	(42,136)	$24.02
Forfeited	(70,631)	$22.86
Restricted units at December 31, 2006	1,105,237	
Granted (4)	738,040	$25.61
Vested	(4,884)	$25.28
Forfeited	(36,800)	$23.51
Settled (5)	(113,053)	$23.24
Restricted units at December 31, 2007	1,688,540	

(1) Determined by dividing the aggregate grant date fair value of awards (including an allowance for forfeitures) by the number of awards issued.

(2) Aggregate grant date fair value of restricted unit awards issued during 2005 was $8.8 million based on grant date market prices of our common units ranging from $25.83 to $26.95 per unit and an estimated forfeiture rate of 8.2%.

(3) Aggregate grant date fair value of restricted unit awards issued during 2006 was $10.8 million based on grant date market prices of our common units ranging from $24.85 to $27.45 per unit and estimated forfeiture rates ranging from 7.8% to 9.8%.

(4) Aggregate grant date fair value of restricted unit awards issued during 2007 was $18.9 million based on grant date market prices of our common units ranging from $28.00 to $31.83 per unit and estimated forfeiture rates ranging from 4.6% to 17.0%.

(5) Reflects the settlement of restricted units in connection with the resignation of our former chief executive officer.

The total fair value of restricted units that vested during the year ended December 31, 2007 was $0.1 million. At December 31, 2007, there was an estimated $25.5 million of total unrecognized compensation cost related to restricted unit awards granted under the 1998 Plan, which we expect to recognize over a weighted-average period of 2.4 years. We will recognize our share of such costs in accordance with the EPCO administrative services agreement.

Phantom unit awards. The 1998 Plan also provides for the issuance of phantom unit awards. These liability awards are automatically redeemed for cash based on the vested portion of the fair market value of the phantom units at redemption dates in each award. The fair market value of each phantom unit award is equal to the market closing price of our common units on the redemption date. Each participant is required to redeem their phantom units as they vest, which typically is four years from the date the award is granted. No phantom unit awards have been issued to date under the 1998 Plan.

The 1998 Plan also provides for the award of distribution equivalent rights ("DERs") in tandem with its phantom unit awards. A DER entitles the participant to cash distributions equal to the product of the number of phantom units outstanding for the participant and the cash distribution rate paid by us to our unitholders.

Employee Partnerships

EPCO formed the Employee Partnerships to serve as an incentive arrangement for key employees of EPCO by providing them a "profits interest" in the Employee Partnerships. Certain EPCO employees who work on behalf of us and EPCO were issued Class B limited partner interests and admitted as Class B limited partners without any capital contribution. The profits interest awards (i.e., the Class B limited partner interests) in the Employee Partnerships entitles each holder to participate in the appreciation in value of Enterprise GP Holdings' Units. The Class B limited partner interests are subject to forfeiture if the participating employee's employment with EPCO is terminated prior to vesting, with customary exceptions for death, disability and certain retirements. The risk of forfeiture will also lapse upon certain change in control events.

Prior to our adoption of SFAS 123(R), the estimated value of these awards was accounted for in a manner similar to a stock appreciation right. Starting January 1, 2006, compensation expense attributable to these awards was based on the estimated grant date fair value of each award. A portion of the fair value of these equity-based awards is allocated to us under the EPCO administrative services agreement as a non-cash expense. We are not responsible for reimbursing EPCO for any expenses of the Employee

Partnerships, including the value of any contributions of cash or units of Enterprise GP Holdings made by private company affiliates of EPCO at the formation of each Employee Partnership.

Currently, there are four Employee Partnerships. EPE Unit I was formed in August 2005 in connection with Enterprise GP Holdings' initial public offering. EPE Unit II was formed in December 2006. EPE Unit III was formed in May 2007.

At December 31, 2007, there was an estimated $26.9 million of combined unrecognized compensation cost related to the Employee Partnerships. We will recognize our share of these costs in accordance with the EPCO administrative services agreement over a weighted-average period of 3.9 years.

The following is a discussion of significant terms of EPE Unit I, EPE Unit II, and EPE Unit III.

EPE Unit I. In connection with the initial public offering of Enterprise GP Holdings in August 2005, EPE Unit I was formed to serve as an incentive arrangement for certain employees of EPCO through a "profits interest" in EPE Unit I. In August 2005, EPE Unit I used $51.0 million in contributions it received from its Class A limited partner (an affiliate of EPCO) to purchase 1,821,428 units of Enterprise GP Holdings. Certain EPCO employees, including all of EPGP's executive officers other than Dan L. Duncan and Dr. Ralph S. Cunningham, were admitted as Class B limited partners of EPE Unit I without any capital contributions.

Unless otherwise agreed to by EPCO, the Class A limited partner and a majority of the Class B limited partners, EPE Unit I will be liquidated upon the earlier of (i) August 2010 or (ii) a change in control of Enterprise GP Holdings or its general partner, EPE Holdings. Upon liquidation of EPE Unit I, units having a fair market value equal to the Class A limited partner's capital base, plus any Class A preferred return for the quarter in which liquidation occurs, will be distributed to the Class A limited partner. Any remaining units will be distributed to the Class B limited partners as a residual profits interest award in EPE Unit I.

As adjusted for forfeitures and regrants, the grant date fair value of the Class B limited partnership interests in EPE Unit I was $12.2 million at December 31, 2007. This fair value was estimated using the Black-Scholes option pricing model, which incorporates various assumptions including (i) an expected life of the awards ranging from three to five years, (ii) risk-free interest rates ranging from 4.1% to 5.0%, (iii) an expected distribution yield on units of Enterprise GP Holdings ranging from 3.0% to 4.2%, and (iv) an expected unit price volatility for Enterprise GP Holdings' units ranging from 17.4% to 30.0%.

EPE Unit II. In December 2006, EPE Unit II, L.P. was formed to serve as an incentive arrangement for Dr. Ralph S. Cunningham, an executive officer of our general partner. The officer, who is not a participant in EPE Unit I, was granted a "profits interest" award in EPE Unit II. EPCO serves as the general partner of EPE Unit II.

At inception, EPE Unit II used $1.5 million in contributions it received from an affiliate of EPCO (which was admitted as the Class A limited partner of EPE Unit II as a result of such contribution) to purchase 40,725 units of Enterprise GP Holdings at an average price of $36.91 per unit in December 2006. The officer was issued a Class B limited partner interest in EPE Unit II without any capital contribution.

Unless otherwise agreed upon by EPCO, the Class A limited partner and the Class B limited partner, EPE Unit II will be liquidated upon the earlier of (i) December 2011 or (ii) a change in control of Enterprise GP Holdings or its general partner, EPE Holdings. Upon liquidation of the EPE Unit II, units having a fair market value equal to the Class A limited partner's capital base will be distributed to the Class A limited partner, plus any Class A preferred return for the quarter in which liquidation occurs. Any remaining units will be distributed to the Class B limited partner as a residual profits interest award in EPE Unit II.

The grant date fair value of the Class B limited partnership interests in EPE Unit II was $0.2 million at December 31, 2007. This fair value was estimated on the date of grant using the Black-Scholes option pricing model, which incorporated various assumptions including (i) an expected life of the award of five years, (ii) risk-free interest rate of 4.4%, (iii) an expected distribution yield on units of Enterprise GP Holdings of 3.8%, and (iv) an expected Enterprise GP Holdings unit price volatility of 18.7%.

EPE Unit III. EPE Unit III owns 4,421,326 units of Enterprise GP Holdings contributed to it by a private company affiliate of EPCO, which, in turn, was made the Class A limited partner of EPE Unit III. The units of Enterprise GP Holdings contributed by the Class A limited partner had a fair value of $170.0 million on the date of contribution (the "Class A limited partner capital base"). Certain EPCO employees were issued Class B limited partner interests and admitted as Class B limited partners of EPE Unit III without any capital contribution. The profits interest awards (i.e., Class B limited partner interests) in EPE Unit III entitle the holder to participate in the appreciation in value of Enterprise GP Holdings' units owned by EPE Unit III.

Unless otherwise agreed to by EPCO, the Class A limited partner and a majority in interest of the Class B limited partners of EPE Unit III, EPE Unit III will be liquidated upon the earlier of: (i) May 7, 2012 or (ii) a change in control of Enterprise GP Holdings or its general partner. EPE Unit III has the following material terms regarding its quarterly cash distribution to partners:

- Distributions of Cash flow - Each quarter, 100% of the cash distributions received by EPE Unit III from Enterprise GP Holdings will be distributed to the Class A limited partner until it has received an amount equal to the pro rata Class A preferred return (as defined below), and any remaining distributions received by EPE Unit III will be distributed to the Class B limited partners. The Class A preferred return equals 3.797% per annum, of the Class A limited partner's capital base. The Class A limited partner's capital base equals approximately $170.0 million plus any unpaid Class A preferred return from prior periods, less any distributions made by EPE Unit III of proceeds from the sale of Enterprise GP Holdings' units owned by EPE Unit III (as described below).

- Liquidating Distributions - Upon liquidation of EPE Unit III, Enterprise GP Holdings' units having a fair market value equal to the Class A limited partner capital base will be distributed to a private company affiliate of EPCO, plus any accrued Class A preferred return for the quarter in which liquidation occurs. Any remaining units of Enterprise GP Holdings will be distributed to the Class B limited partners.

- Sale Proceeds - If EPE Unit III sells any of the 4,421,326 units of Enterprise GP Holdings that it owns, the sale proceeds will be distributed to the Class A limited partner and the Class B limited partners in the same manner as liquidating distributions described above.

The Class B limited partner interests in EPE Unit III that are owned by EPCO employees are subject to forfeiture if the participating employee's employment with EPCO and its affiliates is terminated prior to May 7, 2012, with customary exceptions for death, disability and certain retirements. The risk of forfeiture associated with the Class B limited partner interests in EPE Unit III will also lapse upon certain change of control events.

As adjusted for forfeitures and regrants, the grant date fair value of the Class B limited partnership interests in EPE Unit III was $23.0 million at December 31, 2007. This fair value was estimated using the Black-Scholes option pricing model, which incorporates various assumptions including (i) an expected life of the awards ranging from four to five years, (ii) risk-free interest rates ranging from 3.5% to 4.9%, (iii) an expected distribution yield on units of Enterprise GP Holdings ranging from 4.0% to 4.3%, and (iv) an expected unit price volatility for Enterprise GP Holdings' units ranging from 16.9% to 17.6%.

DEP Holdings, LLC Unit Appreciation Rights

The non-employee directors of DEP Holdings, LLC, the general partner of Duncan Energy Partners ("DEP GP"), have been granted UARs in the form of letter agreements. These liability awards are not part of any established long-term incentive plan of EPCO, Enterprise GP Holdings or us. The compensation expense associated with these awards is recognized by DEP GP, which is our consolidated subsidiary. The UARs entitle each non-employee director to receive a cash payment on the vesting date equal to the excess, if any, of the fair market value of Enterprise GP Holdings' units (determined as of a future vesting date) over the grant date fair value. If a director resigns prior to vesting, his UAR awards are forfeited. These UARs are accounted for similar to liability awards under SFAS 123(R) since they will be settled with cash.

As of December 31, 2007, a total of 90,000 UARs had been granted to non-employee directors of DEP GP that cliff vest in 2012. If a director resigns prior to vesting, his UAR awards are forfeited. The grant date fair value with respect to these UARs is based on an Enterprise GP Holdings' unit price of $36.68.

Note 6. Employee Benefit Plans

Dixie employs the personnel that operate its pipeline system and certain of these employees are eligible to participate in a defined contribution plan and pension and postretirement benefit plans. Due to the immaterial nature of Dixie's employee benefit plans to our consolidated financial position, results of operations and cash flows, our discussion is limited to the following:

Defined Contribution Plan

Dixie contributed $0.3 million to its company-sponsored defined contribution plan for each of the years ended December 31, 2007 and 2006.

Pension and Postretirement Benefit Plans

Dixie's pension plan is a noncontributory defined benefit plan that provides for the payment of benefits to retirees based on their age at retirement, years of service and average compensation. Dixie's postretirement benefit plan also provides medical and life insurance to retired employees. The medical plan is contributory and the life insurance plan is noncontributory. Dixie employees hired after July 1, 2004 are not eligible for pension and other benefit plans after retirement.

The following table presents Dixie's benefit obligations, fair value of plan assets and funded status at December 31, 2007.

	Pension Plan	Postretirement Plan
Projected benefit obligation	$7,250	$5,882
Accumulated benefit obligation	4,971	—
Fair value of plan assets	5,572	—
Unfunded liability	1,678	5,882
Funded status (liability)	1,678	5,882

Projected benefit obligations and net periodic benefit costs are based on actuarial estimates and assumptions. The weighted-average actuarial assumptions used in determining the projected benefit obligation at December 31, 2007 were as follows: discount rate of 5.75%; rate of compensation increase of 4.00% and 5.00% for the pension and postretirement plans, respectively; and a medical trend rate of 8.00% for 2008 grading to an ultimate trend of 5.00% for 2010 and later years. Dixie's net pension and postretirement benefit costs for 2007 were $1.1 million (including settlement loss of $0.6 million) and $0.4 million, respectively. Dixie's net pension and postretirement benefit costs for 2006 were $0.7 million and $0.3 million, respectively.

Future benefits expected to be paid from Dixie's pension and postretirement plans are as follows for the periods indicated:

	Pension Plan	Postretirement Plan
2008	$ 218	$ 389
2009	287	422
2010	324	467
2011	518	505
2012	534	497
2013 through 2017	3,779	2,353
Total	$5,660	$4,633

On December 31, 2006, Dixie adopted the recognition and disclosure provisions of SFAS 158. Dixie uses a December 31 measurement date of these plans. SFAS 158 requires Dixie to recognize the funded status of its defined benefit pension and other postretirement plans as an asset or liability in its statement of financial position and to recognize changes in that funded status in the year in which the changes occur through comprehensive income.

The incremental effects of Dixie's implementation of SFAS 158 on our Consolidated Balance Sheets at December 31, 2006 are presented in the following table.

	At December 31, 2006		
	Prior to Adopting SFAS 158	Effect of Adopting SFAS 158	As reported
Liability for Dixie benefit plans	$ 6,404	$ 751	$ 7,155
Deferred income taxes	—	(287)	(287)
Total liabilities	7,509,021	464	7,509,485
Accumulated other comprehensive income	—	(464)	(464)
Total equity	6,480,697	(464)	6,480,233

Included in Accumulated Other Comprehensive Income ("AOCI") on the Consolidated Balance Sheet at December 31, 2007 and 2006 are the following amounts that have not been recognized in net periodic pension costs (in millions):

	At December 31,	
	2007	2006
Unrecognized transition obligation	$ 1.0	$ 1.2
Net of tax	0.6	0.7
Unrecognized prior service cost credit	(1.2)	(1.5)
Net of tax	(0.8)	(0.9)
Unrecognized net actuarial loss	2.8	3.1
Net of tax	1.7	1.9

Note 7. Financial Instruments

We are exposed to financial market risks, including changes in commodity prices, interest rates and foreign exchange rates. In addition, we are exposed to fluctuations in exchange rates between the U.S. dollar and Canadian dollar. We may use financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to mitigate the risks of certain identifiable and anticipated transactions. In general, the type of risks we attempt to hedge are those related to (i) the variability of future earnings, (ii) fair values of certain debt instruments and (iii) cash flows resulting from changes in applicable interest rates, commodity prices or exchange rates.

We recognize financial instruments as assets and liabilities on our Consolidated Balance Sheets based on fair value. Fair value is generally defined as the amount at which a financial instrument could be exchanged in a current transaction between willing parties, not in a forced or liquidation sale. The estimated fair values of our financial instruments have been determined using available market information and appropriate valuation techniques. We must use considerable judgment, however, in interpreting market data and developing these estimates. Accordingly, our fair value estimates are not necessarily indicative of the amounts that we could realize upon disposition of these instruments. The use of different market assumptions and/or estimation techniques could have a material effect on our estimates of fair value.

Changes in the fair value of financial instrument contracts are recognized currently in earnings unless specific hedge accounting criteria are met. If the financial instruments meet those criteria, the instrument's gains and losses offset the related results of the hedged item in earnings for a fair value hedge and are deferred in other comprehensive income for a cash flow hedge. Gains and losses related to a cash flow hedge are reclassified into earnings when the forecasted transaction affects earnings. For additional information regarding our accounting for financial instruments, see Note 2 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

To qualify as a hedge, the item to be hedged must be exposed to commodity, interest rate or exchange rate risk and the hedging instrument must reduce the exposure and meet the hedging requirements of SFAS 133, "Accounting for Derivative Instruments and Hedging Activities" (as amended and interpreted). We must formally designate the financial instrument as a hedge and document and assess the effectiveness of the hedge at inception and on a quarterly basis. Any ineffectiveness of the hedge is recorded in current earnings.

We routinely review our outstanding financial instruments in light of current market conditions. If market conditions warrant, some financial instruments may be closed out in advance of their contractual settlement dates thus realizing income or loss depending on the specific hedging criteria. When this occurs, we may enter into a new financial instrument to reestablish the hedge to which the closed instrument relates.

Interest Rate Risk Hedging Program

Our interest rate exposure results from variable and fixed rate borrowings under various debt agreements. We manage a portion of our interest rate exposures by utilizing interest rate swaps and similar arrangements, which allow us to convert a portion of fixed rate debt into variable rate debt or a portion of variable rate debt into fixed rate debt. The following information summarizes significant components of our interest rate risk hedging portfolio:

Fair value hedges – Interest rate swaps

As summarized in the following table, we had eleven interest rate swap agreements outstanding at December 31, 2007 that were accounted for as fair value hedges.

Hedged Fixed Rate Debt	Number Of Swaps	Period Covered by Swap	Termination Date of Swap	Fixed to Variable Rate (1)	Notional Amount
Senior Notes B, 7.50% fixed rate, due Feb. 2011	1	Jan. 2004 to Feb. 2011	Feb. 2011	7.50% to 8.65%	$50 million
Senior Notes C, 6.375% fixed rate, due Feb. 2013	2	Jan. 2004 to Feb. 2013	Feb. 2013	6.38% to 7.19%	$200 million
Senior Notes G, 5.6% fixed rate, due Oct. 2014	6	4th Qtr. 2004 to Oct. 2014	Oct. 2014	5.60% to 6.13%	$600 million
Senior Notes K, 4.95% fixed rate, due June 2010	2	Aug. 2005 to June 2010	June 2010	4.95% to 5.33%	$200 million

(1) The variable rate indicated is the all-in variable rate for the current settlement period.

We have designated these eleven interest rate swaps as fair value hedges under SFAS 133 since they mitigate changes in the fair value of the underlying fixed rate debt. As effective fair value hedges, an increase in the fair value of these interest rate swaps is equally offset by an increase in the fair value of the underlying hedged debt. The offsetting changes in fair value have no effect on current period interest expense.

These eleven agreements have a combined notional amount of $1.1 billion and match the maturity dates of the underlying debt being hedged. Under each swap agreement, we pay the counterparty a variable interest rate based on six-month London interbank offered rate ("LIBOR") (plus an applicable margin as defined in each swap agreement), and receive back from the counterparty a fixed interest rate payment based on the stated interest rate of the debt being hedged, with both payments calculated using the notional amounts stated in each swap agreement. We settle amounts receivable from or payable to the counterparties every six months (the "settlement period"). The settlement amount is amortized ratably to earnings as either an increase or a decrease in interest expense over the settlement period.

The total fair value of these eleven interest rate swaps at December 31, 2007, was an asset of $14.8 million, with an offsetting decrease in the fair value of the underlying debt. Interest expense for the years ended December 31, 2007, 2006 and 2005 reflects a $8.9 million loss, $5.2 million loss and $10.8 million benefit from these swap agreements, respectively.

Cash flow hedges – Interest Rate Swaps

Duncan Energy Partners had three interest rate swap agreements outstanding at December 31, 2007 that were accounted for as cash flow hedges.

Hedged Variable Rate Debt	Number Of Swaps	Period Covered by Swap	Termination Date of Swap	Variable to Fixed Rate(1)	Notional Value
Duncan Energy Partners' Revolver, due Feb. 2011	3	Sep. 2007 to Sep. 2010	Sep. 2010	4.84% to 4.62%	$175.0 million

(1) Amounts receivable from or payable to the swap counterparties are settled every three months (the "settlement period").

In September 2007, Duncan Energy Partners executed three floating-to-fixed interest rate swaps having a combined notional value of $175.0 million. The purpose of these financial instruments is to reduce the sensitivity of Duncan Energy Partners' earnings to variable interest rates charged under its revolving credit facility. It recognized a $0.2 million benefit from these swaps in interest expense during 2007, which includes ineffectiveness of $0.2 million (an expense) and income of $0.4 million. In 2008, Duncan Energy Partners expects to reclassify $0.7 million of accumulated other comprehensive loss that was generated by these interest rate swaps as an increase to interest expense.

At December 31, 2007, the aggregate fair value of these interest rate swaps was a liability of $3.8 million. As cash flow hedges, any increase or decrease in fair value (to the extent effective) would be recorded into other comprehensive income and amortized into income based on the settlement period hedged. Any ineffectiveness is recorded directly into earnings as an increase in interest expense.

Cash flow hedges – Treasury locks

At times, we may use treasury lock financial instruments to hedge the underlying U.S. treasury rates related to our anticipated issuances of debt. A treasury lock is a specialized agreement that fixes the price (or yield) on a specific treasury security for an established period of time. A treasury lock purchaser is protected from a rise in the yield of the underlying treasury security during the lock period. Each of the treasury lock transactions was designated as a cash flow hedge under SFAS 133.

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To the extent effective, gains and losses on the value of the treasury locks will be deferred until the forecasted debt is issued and will be amortized to earnings over the life of the debt. No ineffectiveness was recognized as of December 31, 2007. Gains or losses on the termination of such instruments are amortized to earnings using the effective interest method over the estimated term of the underlying fixed-rate debt. The following table summarizes changes in our treasury lock portfolio since December 31, 2005 (dollars in millions):

	Notional Amount	Cash Gain
Second quarter of 2006 additions to portfolio (1)	$ 250.0	$ —
Third quarter of 2006 additions to portfolio (1)	50.0	—
Third quarter of 2006 terminations (2)	(300.0)	—
Fourth quarter of 2006 additions to portfolio (3)	562.5	—
Treasury lock portfolio, December 31, 2006 (4)	562.5	—
First quarter of 2007 additions to portfolio (3)	437.5	—
Second quarter of 2007 terminations (5)	(875.0)	42.3
Third quarter of 2007 additions to portfolio (6)	875.0	—
Third quarter of 2007 terminations (7)	(750.0)	6.6
Fourth quarter of 2007 additions to portfolio (8)	350.0	—
Treasury lock portfolio, December 31, 2007 (4)	$ 600.0	$48.9

(1) EPO entered into these transactions related to its anticipated issuances of debt in 2006.

(2) Terminations relate to the issuance of the Junior Notes A ($300.0 million).

(3) EPO entered into these transactions related to its anticipated issuances of debt in 2007.

(4) The fair value of open financial instruments at December 31, 2006 and 2007 was an asset of $11.2 million and a liability of $19.6 million, respectively.

(5) Terminations relate to the issuance of the Junior Notes B ($500.0 million) and Senior Notes L ($375.0 million). Of the $42.3 million gain, $10.6 million relates to the Junior Notes B and the remainder to the Senior Notes L and its successor debt.

(6) EPO entered into these transactions related to its issuance of the Senior Notes L (including its successor debt) in August 2007 ($500.0 million) and anticipated issuance of debt during the first half of 2008 ($250.0 million).

(7) Terminations relate to the issuance of the Senior Notes L and its successor debt.

(8) EPO entered into these transactions in anticipated issuance of debt during the first half of 2008.

Commodity Risk Hedging Program

The prices of natural gas, NGLs and certain petrochemical products are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control. In order to manage the price risks associated with such products, we may enter into commodity financial instruments.

The primary purpose of our commodity risk management activities is to hedge our exposure to price risks associated with (i) natural gas purchases, (ii) the value of NGL production and inventories, (iii) related firm commitments, (iv) fluctuations in transportation revenues where the underlying fees are based on natural gas index prices and (v) certain anticipated transactions involving either natural gas, NGLs or certain petrochemical products. From time to time, we inject natural gas into storage and utilize hedging instruments to lock in the value of our inventory positions. The commodity financial instruments we utilize may be settled in cash or with another financial instrument.

The fair value of our commodity financial instrument portfolio, which primarily consisted of cash flow hedges, at December 31, 2007 was a liability of $19.3 million. During the years ended December 31, 2007, 2006 and 2005, we recorded a $28.6 million loss, $10.3 million income and $1.1 million income, respectively, related to our commodity financial instruments, which is included in operating costs and expenses on our Statements of Consolidated Operations. Included in the $28.6 million loss recorded during 2007, was ineffectiveness of $0.9 million (an expense) related to our commodity hedges. These contracts will terminate during 2008, and any amounts remaining in accumulated other comprehensive income will be recorded in earnings.

Foreign Currency Hedging Program

We are exposed to foreign currency exchange rate risk through our Canadian NGL marketing subsidiary and certain construction agreements with respect to our Pioneer processing plant where payments are indexed to the Canadian dollar. As a result, we could be adversely affected by fluctuations in the foreign currency exchange rate between the U.S. dollar and the Canadian dollar. We attempt to hedge this risk using foreign exchange purchase contracts to fix the exchange rate.

Mark-to-market accounting is utilized for those foreign exchange contracts associated with our Canadian NGL marketing business. The duration of these contracts is typically one month. As of December 31, 2007, $4.7 million of these exchange contracts were outstanding, all of which settled in January 2008. In January 2008, we entered into $3.7 million of such instruments.

The foreign exchange contracts associated with our construction activities are accounted for using hedge accounting. At December 31, 2007, the fair value of these contracts was $1.3 million. These contracts settle through May 2008.

Fair Value Information

Cash and cash equivalents, accounts receivable, accounts payable and accrued expenses are carried at amounts which reasonably approximate their fair values due to their short-term nature. The estimated fair values of our fixed rate debt are based on quoted market prices for such debt or debt of similar terms and maturities. The carrying amounts of our variable rate debt obligations reasonably approximate their fair values due to their variable interest rates. The fair values associated with our interest rate and commodity hedging portfolios were developed using available market information and appropriate valuation techniques. The following table presents the estimated fair values of our financial instruments at the dates indicated:

	At December 31, 2007		At December 31, 2006	
Financial Instruments	Carrying Value	Fair Value	Carrying Value	Fair Value
Financial assets:				
Cash and cash equivalents	$ 92,866	$ 92,866	$ 46,286	$ 46,286
Accounts receivable	2,010,544	2,010,544	1,323,028	1,323,028
Commodity financial instruments (1)	338	338	1,472	1,472
Foreign currency hedging financial instruments (2)	1,308	1,308	—	—
Interest rate hedging financial instruments (3)	14,839	14,839	11,203	11,203
Financial liabilities:				
Accounts payable and accrued expenses	2,755,647	2,755,647	1,774,976	1,774,976
Fixed-rate debt (principal amount)	5,904,000	5,867,899	4,909,068	4,955,176
Variable-rate debt	992,500	992,500	420,000	420,000
Commodity financial instruments (1)	19,643	19,643	4,655	4,655
Foreign currency hedging financial instruments (2)	27	27	—	—
Interest rate hedging financial instruments (3)	23,422	23,422	29,060	29,060

(1) Represent commodity financial instrument transactions that either have not settled or have settled and not been invoiced. Settled and invoiced transactions are reflected in either accounts receivable or accounts payable depending on the outcome of the transaction.

(2) Relates to the hedging of our exposure to fluctuations in the Canadian dollar.

(3) Represent interest rate hedging financial instrument transactions that have not settled. Settled transactions are reflected in either accounts receivable or accounts payable depending on the outcome of the transaction.

Note 8. Cumulative Effect of Changes in Accounting Principles

During the years ended December 31, 2006 and 2005, we recorded various amounts related to the cumulative effect of changes in accounting principles, including a benefit of $1.5 million in January 2006 related to the implementation of SFAS 123(R) and a charge of $4.2 million in December 2005 related to our implementation of FIN 47.

See Note 6 regarding the balance sheet impact of adopting SFAS 158 at December 31, 2006, which had no effect on net income.

Effect of Implementation of Staff Accounting Bulletin ("SAB") 108

SAB 108, "Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements," addresses how the effects of the carryover or reversal of prior year misstatements should be considered in quantifying a current year misstatement. This SAB requires us to quantify errors using both a balance sheet and an income statement approach and evaluate whether either approach results in quantifying a misstatement that, when all relevant quantitative and qualitative factors are considered, is material. The provisions of SAB 108 did not have a material impact on our consolidated financial statements.

Effect of Implementation of SFAS 123(R)

SFAS 123(R) requires us to recognize compensation expense related to unit-based awards based on the fair value of the award at grant date. The fair value of restricted unit awards is based on the market price of the underlying common units on the date of grant. The fair value of other unit-based awards is estimated using the Black-Scholes option pricing model. Under SFAS 123(R), the fair value of an equity-classified award is amortized to earnings on a straight-line basis over the requisite service or vesting period for equity-classified awards. Compensation for liability-classified awards is recognized over the requisite service or vesting period of an award based on the fair value of the award remeasured at each reporting period. Liability awards will be cash settled upon vesting.

Upon adoption of SFAS 123(R), we recognized, as a benefit, the cumulative effect of a change in accounting principle of $1.5 million based on the SFAS 123(R) requirement to recognize compensation expense based upon the grant date fair value of unit-based awards and the application of an estimated forfeiture rate to unvested awards. See Notes 2 and 5 for additional information regarding our accounting for equity awards.

Effect of Implementation of FIN 47

In December 2005, we adopted FIN 47, "Accounting for Conditional Asset Retirement Obligations – An Interpretation for FAS 143," which required us to record a liability for AROs in which the timing and/or amount of settlement of the obligation is uncertain. These conditional asset retirement obligations were not addressed in SFAS 143, which we adopted on January 1, 2003. We recorded a charge of $4.2 million in connection with our implementation of FIN 47, which represents the depreciation and accretion expense we would have recognized in prior periods had we recorded these conditional asset retirement obligations when incurred. See Note 10 for additional information regarding our AROs.

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The following table shows unaudited pro forma net income for the years ended December 31, 2006 and 2005, assuming these accounting changes noted above were applied retroactively to January 1, 2005.

	For the Years Ended December 31,	
	2006	2005
Pro Forma income statement amounts:		
Historical net income	$601,155	$419,508
Adjustments to derive pro forma net income:		
Effect of implementation of SFAS 123(R):		
Remove cumulative effect of change in accounting principle recorded in January 2006	(1,472)	—
Additional compensation expense that would have been recorded for unit options	—	(708)
Remove compensation expense related to awards of profits interests in EPE Unit L.P.	—	1,271
Effect of implementation of FIN 47:		
Remove cumulative effect of change in accounting principle recorded in December 2005	—	4,208
Record depreciation and accretion expense associated with conditional asset retirement obligations	—	(735)
Pro forma net income	599,683	423,544
EPGP interest	(96,969)	(71,077)
Pro forma net income available to limited partners	$502,714	$352,467
Pro forma per unit data (basic):		
Historical units outstanding	414,442	382,463
Per unit data:		
As reported	$ 1.22	$ 0.91
Pro forma	$ 1.21	$ 0.92
Pro forma per unit data (diluted):		
Historical units outstanding	414,759	382,963
Per unit data:		
As reported	$ 1.22	$ 0.91
Pro forma	$ 1.21	$ 0.92

Note 9. Inventories

Our inventory amounts were as follows at the dates indicated:

	At December 31,	
	2007	2006
Working inventory (1)	$ 342,589	$ 387,973
Forward-sales inventory (2)	11,693	35,871
Total inventory	$ 354,282	$ 423,844

(1) Working inventory is comprised of inventories of natural gas, NGLs and certain petrochemical products that are either available-for-sale or used in the provision for services.

(2) Forward sales inventory consists of segregated NGL and natural gas volumes dedicated to the fulfillment of forward-sales contracts.

Our inventory values reflect payments for product purchases, freight charges associated with such purchase volumes, terminal and storage fees, vessel inspection costs, demurrage charges and other related costs. We value our inventories at the lower of average cost or market.

Operating costs and expenses, as presented on our Statements of Consolidated Operations, include cost of sales amounts related to the sale of inventories. Our costs of sales were $14.5 billion, $11.8 billion and $10.3 billion for the years ended December 31, 2007, 2006 and 2005, respectively.

In those instances where we take ownership of inventory volumes through percent-of-liquids contracts and similar arrangements (as opposed to actually purchasing volumes for cash from third parties, see Note 4), these volumes are valued at market-related prices during the month in which they are acquired. We capitalize as a component of inventory those ancillary costs (e.g. freight-in and other handling and processing charges) incurred in connection with volumes obtained through such contracts.

Due to fluctuating commodity prices in the NGL, natural gas and petrochemical industry, we recognize lower of cost or market ("LCM") adjustments when the carrying value of our inventories exceed their net realizable value. These non-cash charges are a component of cost of sales in the period they are recognized and generally affect our segment operating results in the following manner:

- Write-downs of NGL inventories are recorded as a cost of our NGL marketing activities within our NGL Pipelines & Services business segment;
- Write-downs of natural gas inventories are recorded as a cost of our natural gas pipeline operations within our Onshore Natural Gas Pipelines & Services business segment; and
- Write-downs of petrochemical inventories are recorded as a cost of our petrochemical marketing activities or octane additive production business within our Petrochemical Services business segment, as applicable.

For the years ended December 31, 2007, 2006 and 2005, we recognized LCM adjustments of approximately $13.3 million, $18.6 million and $21.9 million, respectively. To the extent our commodity hedging strategies address inventory-related risks and are successful, these inventory valuation adjustments are mitigated or offset. See Note 7 for a description of our commodity hedging activities.

Note 10. Property, Plant and Equipment

Our property, plant and equipment values and accumulated depreciation balances were as follows at the dates indicated:

	Estimated Useful Life in Years	At December 31, 2007	At December 31, 2006
Plants and pipelines (1)	3-35 (5)	$10,884,819	$ 8,774,683
Underground and other storage facilities (2)	5-35 (6)	720,795	596,649
Platforms and facilities (3)	23-31	637,812	161,839
Transportation equipment (4)	3-10	32,627	27,008
Land		48,172	40,010
Construction in progress		1,173,988	1,734,083
Total		13,498,213	11,334,272
Less accumulated depreciation		1,910,949	1,501,725
Property, plant and equipment, net		$11,587,264	$ 9,832,547

(1) Plants and pipelines include processing plants; NGL, petrochemical, oil and natural gas pipelines; terminal loading and unloading facilities; office furniture and equipment; buildings; laboratory and shop equipment; and related assets.

(2) Underground and other storage facilities include underground product storage caverns; storage tanks; water wells; and related assets.

(3) Platforms and facilities include offshore platforms and related facilities and other associated assets.

(4) Transportation equipment includes vehicles and similar assets used in our operations.

(5) In general, the estimated useful lives of major components of this category are as follows: processing plants, 20-35 years; pipelines, 18-35 years (with some equipment at 5 years); terminal facilities, 10-35 years; office furniture and equipment, 3-20 years; buildings 20-35 years; and laboratory and shop equipment, 5-35 years.

(6) In general, the estimated useful lives of major components of this category are as follows: underground storage facilities, 20-35 years (with some components at 5 years); storage tanks, 10-35 years; and water wells, 25-35 years (with some components at 5 years).

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The following table summarizes our depreciation expense and capitalized interest amounts for the periods indicated:

	For the Years Ended December 31,		
	2007	2006	2005
Depreciation expense (1)	$414,901	$350,832	$328,736
Capitalized interest (2)	$ 75,476	$ 55,660	$ 22,046

(1) Depreciation expense is a component of operating costs and expenses as presented in our Statements of Consolidated Operations.

(2) Capitalized interest increases the carrying value of the associated asset and reduces interest expense during the period it is recorded.

Asset retirement obligations

We have recorded asset retirement obligations related to legal requirements to perform retirement activities as specified in contractual arrangements and/or governmental regulations. In general, our asset retirement obligations primarily result from (i) right-of-way agreements associated with our pipeline operations, (ii) leases of plant sites and (iii) regulatory requirements triggered by the abandonment or retirement of certain underground storage assets and offshore facilities. In addition, our asset retirement obligations may result from the renovation or demolition of certain assets containing hazardous substances such as asbestos.

Previously, we recorded asset retirement obligations associated with the future retirement and removal activities of certain offshore assets located in the Gulf of Mexico. In December 2005, we adopted FIN 47 and recorded an additional $10.1 million in connection with conditional asset retirement obligations. The cumulative effect of this change in accounting principle for years prior to 2005 was a non-cash charge of $4.2 million. None of our assets are legally restricted for purposes of settling asset retirement obligations.

The following table presents information regarding our asset retirement obligations since December 31, 2005.

Asset retirement obligation liability balance, December 31, 2005	$ 16,795
Liabilities incurred	1,977
Liabilities settled	(1,348)
Revisions in estimated cash flows	5,650
Accretion expense	1,329
Asset retirement obligation liability balance, December 31, 2006	24,403
Liabilities incurred	1,673
Liabilities settled	(5,069)
Revisions in estimated cash flows	15,645
Accretion expense	3,962
Asset retirement obligation liability balance, December 31, 2007	$ 40,614

Property, plant and equipment at December 31, 2007 and 2006 includes $10.6 million and $3.0 million, respectively, of asset retirement costs capitalized as an increase in the associated long-lived asset. Also, based on information currently available, we estimate that accretion expense will approximate $2.0 million for each of the years 2008 and 2009, $2.1 million for 2010, $2.3 million for 2011 and $2.5 million for 2012.

Certain of our unconsolidated affiliates have AROs recorded at December 31, 2007 and 2006 relating to contractual agreements and regulatory requirements. These amounts are immaterial to our financial statements.

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Note 11. Investments In and Advances to Unconsolidated Affiliates

We own interests in a number of related businesses that are accounted for using the equity method of accounting. Our investments in and advances to unconsolidated affiliates are grouped according to the business segment to which they relate. See Note 16 for a general discussion of our business segments. The following table shows our investments in and advances to unconsolidated affiliates at the dates indicated.

	Ownership Percentage at December 31, 2007	Investments in and advances to Unconsolidated Affiliates at December 31, 2007	December 31, 2006
NGL Pipelines & Services:			
VESCO	13.1%	$ 40,129	$ 39,618
K/D/S Promix, L.L.C. ("Promix")	50%	51,537	46,140
Baton Rouge Fractionators LLC ("BRF")	32.3%	25,423	25,471
Onshore Natural Gas Pipelines & Services:			
Jonah Gas Gathering Company ("Jonah")	19.4%	235,837	120,370
Evangeline (1)	49.5%	3,490	4,221
Offshore Pipelines & Services:			
Poseidon Oil Pipeline, L.L.C. ("Poseidon")	36%	58,423	62,324
Cameron Highway Oil Pipeline Company ("Cameron Highway") (2)	50%	256,588	60,216
Deepwater Gateway, L.L.C. ("Deepwater Gateway")	50%	111,221	117,646
Neptune Pipeline Company, L.L.C. ("Neptune") (3)	25.7%	55,468	58,789
Nemo Gathering Company, LLC ("Nemo") (4)	33.9%	2,888	11,161
Petrochemical Services:			
Baton Rouge Propylene Concentrator, LLC ("BRPC")	30%	13,282	13,912
La Porte (5)	50%	4,053	4,691
Total		$858,339	$564,559

(1) Refers to our ownership interests in Evangeline Gas Pipeline Company, L.P. and Evangeline Gas Corp., collectively.

(2) During the year ended December 31, 2007, we contributed $216.5 million to Cameron Highway to fund our portion of the repayment of Cameron Highway’s debt.

(3) The December 31, 2006 amount includes a $7.4 million non-cash impairment charge attributable to our investment in Neptune.

(4) The December 31, 2007 amount includes a $7.0 million non-cash impairment charge attributable to our investment in Nemo.

(5) Refers to our ownership interests in La Porte Pipeline Company, L.P. and La Porte GP, LLC, collectively.

On occasion, the price we pay to acquire an ownership interest in a company exceeds the underlying book value of the capital accounts we acquire. Such excess cost amounts are included within the carrying values of our investments in and advances to unconsolidated affiliates. At December 31, 2007 and 2006, our investments in Promix, La Porte, Neptune, Poseidon, Cameron Highway, Nemo and Jonah included excess cost amounts totaling $43.8 million and $38.7 million, respectively, all of which were attributable to the fair value of the underlying tangible assets of these entities exceeding their book carrying values at the time of our acquisition of interests in these entities. To the extent that we attribute all or a portion of an excess cost amount to higher fair values, we amortize such excess cost as a reduction in equity earnings in a manner similar to depreciation. To the extent we attribute an excess cost amount to goodwill, we do not amortize this amount but it is subject to evaluation for impairment. Amortization of such excess cost amounts was $2.6 million, $2.1 million and $2.3 million for the years ended December 31, 2007, 2006 and 2005, respectively.

The following table presents our equity in income (loss) of unconsolidated affiliates for the periods indicated:

	For the Year Ended December 31,		
	2007	2006	2005
NGL Pipelines & Services:			
Dixie	$ —	$ —	$ 1,103
VESCO	3,507	1,719	1,412
Belle Rose	—	—	(151)
Promix	514	1,353	1,876
BRF	2,010	2,643	1,313
Onshore Natural Gas Pipelines & Services:			
Evangeline	183	958	331
Coyote	—	1,676	2,053
Jonah	9,357	238	—
Offshore Pipelines & Services:			
Poseidon	10,020	11,310	7,279
Cameron Highway (1)	(11,200)	(11,000)	(15,872)
Deepwater Gateway	20,606	18,392	10,612
Neptune (2)	(821)	(8,294)	2,019
Nemo (3)	(5,977)	1,501	1,774
Starfish Pipeline Company, LLC ("Starfish") (4)	—	—	313
Petrochemical Services:			
BRPC	2,266	1,864	1,224
La Porte	(807)	(795)	(738)
Total	$ 29,658	$ 21,565	$ 14,548

(1) Equity earnings from Cameron Highway for the year ended December 31, 2005 were reduced by a charge of $11.5 million for costs associated with the refinancing of Cameron Highway's project debt.

(2) Equity earnings from Neptune for 2006 include a $7.4 million non-cash impairment charge.

(3) Equity earnings from Nemo for 2007 include a $7.0 million non-cash impairment charge.

(4) We were required under a consent decree published for comment by the U.S. Federal Trade Commission on September 30, 2004 to sell our 50% interest in Starfish. On March 31, 2005, we sold this asset to a third-party.

NGL Pipelines & Services

At December 31, 2007, our NGL Pipelines & Services segment included the following unconsolidated affiliates accounted for using the equity method:

VESCO. We own a 13.1% interest in VESCO, which owns a natural gas processing facility and related assets located in south Louisiana.

Promix. We own a 50.0% interest in Promix, which owns an NGL fractionation facility and related storage and pipeline assets located in south Louisiana.

BRF. We own an approximate 32.3% interest in BRF, which owns an NGL fractionation facility located in south Louisiana.

The combined balance sheet information for the last two years and results of operations data for the last three years of this segment's current unconsolidated affiliates are summarized below.

	At December 31, 2007	At December 31, 2006
BALANCE SHEET DATA:		
Current assets	$112,352	$ 62,138
Property, plant and equipment, net	270,586	242,083
Other assets	11,686	12,189
Total assets	$394,624	$316,410
Current liabilities	$ 75,314	$ 30,686
Other liabilities	9,095	8,117
Combined equity	310,215	277,607
Total liabilities and combined equity	$394,624	$316,410

	For the Year Ended December 31, 2007	2006	2005
INCOME STATEMENT DATA:			
Revenues	$220,381	$190,320	$207,775
Operating income (loss)	41,147	(26,885)	6,696
Net income (loss)	26,506	(25,543)	6,509

Onshore Natural Gas Pipelines & Services

At December 31, 2007, our Onshore Natural Gas Pipelines & Services segment included the following unconsolidated affiliates accounted for using the equity method:

Evangeline. We own an approximate 49.5% aggregate interest in Evangeline, which owns a natural gas pipeline located in south Louisiana. A subsidiary of Acadian Gas, LLC owns the Evangeline interests, which were contributed to Duncan Energy Partners in February 2007 in connection with its initial public offering (see Note 17).

Coyote. We owned a 50.0% interest in Coyote during 2005, which owns a natural gas treating facility located in the San Juan Basin of southwestern Colorado. During 2006, we sold our interest in Coyote and recorded a gain on the sale of $3.3 million.

Jonah. Our equity interest in Jonah at December 31, 2007 is based on capital contributions we made to Jonah in connection with its Phase V expansion project through this date. We completed Phase I of this expansion in July 2007 entitling us to approximately 19.4% in earnings and ownership with the remaining 80.6% entitlement to TEPPCO. See Note 17 for additional information regarding our Jonah affiliate. Jonah owns the Jonah Gas Gathering System located in the Greater Green River Basin of southwestern Wyoming.

The combined balance sheet information for the last two years and results of operations data for the last three years of this segment's current unconsolidated affiliates are summarized below.

	At December 31, 2007	At December 31, 2006
BALANCE SHEET DATA:		
Current assets	$ 83,962	$ 65,048
Property, plant and equipment, net	915,572	639,641
Other assets	176,091	192,027
Total assets	$1,175,625	$896,716
Current liabilities	$ 43,951	$ 49,708
Other liabilities	25,002	28,802
Combined equity	1,106,672	818,206
Total liabilities and combined equity	$1,175,625	$896,716

	For the Year Ended December 31, 2007	2006	2005
INCOME STATEMENT DATA:			
Revenues	$477,077	$372,240	$347,561
Operating income	98,549	48,387	9,142
Net income	93,491	40,608	4,668

Offshore Pipelines & Services

At December 31, 2007, our Offshore Pipelines & Services segment included the following unconsolidated affiliates accounted for using the equity method:

Poseidon. We own a 36.0% interest in Poseidon, which owns a crude oil pipeline that gathers production from the outer continental shelf and deepwater areas of the Gulf of Mexico for delivery to onshore locations in south Louisiana.

Cameron Highway. We own a 50.0% interest in Cameron Highway, which owns a crude oil pipeline that gathers production from deepwater areas of the Gulf of Mexico, primarily the South Green Canyon area, for delivery to refineries and terminals in southeast Texas. The Cameron Highway Oil Pipeline commenced operations during the first quarter of 2005.

Cameron Highway repaid its $365.0 million Series A notes and $50.0 million Series B notes in 2007 using cash contributions from its partners. We funded our 50% share of the capital contributions using borrowings under EPO's Multi-Year Revolving Credit Facility. Cameron Highway incurred a $14.1 million make-whole premium in connection with the repayment of its Series A notes.

Deepwater Gateway. We own a 50.0% interest in Deepwater Gateway, which owns the Marco Polo platform located in the Gulf of Mexico. The Marco Polo platform processes crude oil and natural gas production from the Marco Polo, K2, K2 North and Ghengis Khan fields located in the South Green Canyon area of the Gulf of Mexico.

Neptune. We own a 25.7% interest in Neptune, which owns the Manta Ray Offshore Gathering and Nautilus Systems, which are natural gas pipelines located in the Gulf of Mexico.

Nemo. We own a 33.9% interest in Nemo, which owns the Nemo Gathering System, which is a natural gas pipeline located in the Gulf of Mexico.

In connection with obtaining regulatory approval for the GulfTerra Merger, we were required by the U.S. Federal Trade Commission to sell our ownership interest in Starfish by March 31, 2005. In March 2005, we sold this asset to a third-party for $42.1 million in cash and realized a gain on the sale of $5.5 million.

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The combined balance sheet information for the last two years and results of operations data for the last three years of this segment's current unconsolidated affiliates are summarized below.

	At December 31, 2007	At December 31, 2006
BALANCE SHEET DATA:		
Current assets	$ 46,795	$ 56,689
Property, plant and equipment, net	1,122,108	1,178,811
Other assets	4,338	10,108
Total assets	$1,173,241	$1,245,608
Current liabilities	$ 19,720	$ 22,043
Other liabilities	96,791	510,773
Combined equity	1,056,730	712,792
Total liabilities and combined equity	$1,173,241	$1,245,608

	For the Year Ended December 31, 2007	2006	2005
INCOME STATEMENT DATA:			
Revenues	$156,780	$153,996	$154,297
Operating income	85,550	71,977	78,027
Net income	53,590	42,732	29,086

Neptune owns the Manta Ray Offshore Gathering System ("Manta Ray") and Nautilus Pipeline System ("Nautilus"). Manta Ray gathers natural gas originating from producing fields located in the Green Canyon, Southern Green Canyon, Ship Shoal, South Timbalier and Ewing Bank areas of the Gulf of Mexico to numerous downstream pipelines, including the Nautilus pipeline. Nautilus connects our Manta Ray pipeline to our Neptune natural gas processing plant located in south Louisiana. Due to a recent decrease in throughput volumes on the Manta Ray and Nautilus pipelines, we evaluated our 25.7% investment in Neptune for impairment during the third quarter of 2006. The decrease in throughput volumes is primarily due to underperformance of certain fields, natural depletion and hurricane-related delays in starting new production. These factors contributed to significant delays in throughput volumes Neptune expects to receive. As a result, Neptune has experienced operating losses in recent periods.

At December 31, 2005, the carrying value of our investment in Neptune was $68.1 million, which included $10.9 million of excess cost related to its original acquisition in 2001. Our review of Neptune's estimated cash flows during the third quarter of 2006 indicated that the carrying value of our investment exceeded its fair value, which resulted in a non-cash impairment charge of $7.4 million. This loss is recorded as a component of "Equity in income of unconsolidated affiliates" in our Statement of Consolidated Operations for the year ended December 31, 2006. After recording this impairment charge, the carrying value of our investment in Neptune at December 31, 2006 was $58.8 million.

Nemo was formed in 1999 to construct, own and operate the Nemo Gathering System, a 24-mile natural gas gathering system in the Gulf of Mexico offshore Louisiana. The Nemo Gathering System, which began operations in 2001, gathers natural gas from certain developments in the Green Canyon area of the Gulf of Mexico to a pipeline interconnect with the Manta Ray Gathering System. Due to a recent decrease in throughput volumes on the Nemo Gathering System, we evaluated our 33.9% investment in Nemo for impairment during the second quarter of 2007. The decrease in throughput volumes is primarily due to underperformance of certain fields and natural depletion.

At December 31, 2006, the carrying value of our investment in Nemo was $11.2 million, which included $0.6 million of excess cost related to its original acquisition in 2001. Our review of Nemo's estimated future cash flows during the second quarter of 2007 indicated that the carrying value of our investment exceeded its fair value, which resulted in a non-cash impairment charge of $7.0 million. This loss is recorded as a component of "Equity in income of unconsolidated affiliates" in our Statement of Consolidated Operations for the year ended December 31, 2007. After recording this impairment charge, the carrying value of our investment in Nemo at December 31, 2007 was $2.9 million.

Our investments in Neptune and Nemo were written down to fair value, which management estimated using recognized business valuation techniques. The fair value analysis is based upon management's expectation of future cash flows, which incorporates certain industry information and assumptions made by management. For example, the individual reviews of Neptune and Nemo included management estimates regarding natural gas reserves of producers served by both Neptune and Nemo, respectively. If the assumptions underlying our fair value analysis change and expected cash flows are reduced, additional impairment charges may result.

Petrochemical Services

At December 31, 2007, our Petrochemical Services segment included the following unconsolidated affiliates accounted for using the equity method:

BRPC. We own a 30.0% interest in BRPC, which owns a propylene fractionation facility located in south Louisiana.

La Porte. We own an aggregate 50.0% interest in La Porte, which owns a propylene pipeline extending from Mont Belvieu, Texas to La Porte, Texas.

The combined balance sheet information for the last two years and results of operations data for the last three years of this segment's current unconsolidated affiliates are summarized below.

	At December 31,	
	2007	2006
BALANCE SHEET DATA:		
Current assets	$ 3,187	$ 3,324
Property, plant and equipment, net	47,322	51,159
Total assets	$50,509	$54,483
Current liabilities	$ 970	$ 832
Other liabilities	2	2
Combined equity	49,537	53,649
Total liabilities and combined equity	$50,509	$54,483

	For the Year Ended December 31,		
	2007	2006	2005
INCOME STATEMENT DATA:			
Revenues	$19,844	$19,014	$16,849
Operating income	5,961	4,626	2,606
Net income	6,029	4,729	2,650

Note 12. Business Combinations

2007 Transactions

Our expenditures for business combination during the year ended December 31, 2007 were $35.8 million, which primarily reflect the $35.0 million we spent to acquire the South Monco natural gas pipeline business ("South Monco") in December 2007. This business includes approximately 128 miles of natural gas pipelines located in southeast Texas. The remaining business combination-related amounts for 2007 consist of purchase price adjustments to prior period transactions.

On a pro forma consolidated basis, our revenues, costs and expenses, operating income, net income and earnings per unit amounts would not have differed materially from those we actually reported for 2007 and 2006 due to immaterial nature of our 2007 business combination transactions.

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We accounted for our 2007 business combinations using the purchase method of accounting and, accordingly, such costs have been allocated to assets acquired and liabilities assumed based on estimated preliminary fair values. Such preliminary values have been developed using recognized business valuation techniques and are subject to change pending a final valuation analysis. We expect to finalize the purchase price allocations for these transactions during 2008.

	South Monco Acquisition	Other	Total
Assets acquired in business combination:			
Property, plant and equipment, net	$36,000	$ 8,386	$44,386
Intangible assets	—	(8,460)	(8,460)
Total assets acquired	36,000	(74)	35,926
Liabilities assumed in business combination:			
Other long-term liabilities	(1,000)	(244)	(1,244)
Total liabilities assumed	(1,000)	(244)	(1,244)
Total assets acquired less liabilities assumed	35,000	(318)	34,682
Total cash used for business combinations	35,000	793	35,793
Goodwill	$ —	$ 1,111	$ 1,111

2006 Transactions

Our expenditures for business combinations during the year ended December 31, 2006 were $276.5 million and primarily reflect the Encinal and Piceance Creek acquisitions described below.

Encinal Acquisition. In July 2006, we acquired the Encinal and Canales natural gas gathering systems and related gathering and processing contracts that comprised the South Texas natural gas transportation and processing business of an affiliate of Lewis Energy Group, L.P. ("Lewis"). The aggregate value of total consideration we paid or issued to complete this business combination (referred to as the "Encinal acquisition") was $326.3 million, which consisted of $145.2 million in cash and 7,115,844 of our common units.

The Encinal and Canales gathering systems are located in South Texas and are connected to over 1,450 natural gas wells producing from the Olmos and Wilcox formations. The Encinal system consists of 449 miles of pipeline, which is comprised of 277 miles of pipeline we acquired from Lewis in this transaction and 172 miles of pipeline that we own and had previously leased to Lewis. The Canales gathering system is comprised of 32 miles of pipeline. Currently, natural gas volumes gathered by the Encinal and Canales systems are transported by our existing Texas Intrastate System and are processed by our South Texas natural gas processing plants.

The Encinal and Canales gathering systems will be supported by a life of reserves gathering and processing dedication by Lewis related to its natural gas production from the Olmos formation. In addition, we entered into a 10-year agreement with Lewis for the transportation of natural gas treated at its proposed Big Reef facility. This facility will treat natural gas from the southern portion of the Edwards Trend in South Texas. We also entered into a 10-year agreement with Lewis for the gathering and processing of rich gas it produces from below the Olmos formation.

The total consideration we paid or granted to Lewis in connection with the Encinal acquisition is as follows:

Cash payment to Lewis	$ 145,197
Fair value of our 7,115,844 common units issued to Lewis	181,112
Total consideration	$ 326,309

In accordance with purchase accounting, the value of our common units issued to Lewis was based on the average closing price of such units immediately prior to and after the transaction was announced on July 12, 2006. For purposes of this calculation, the average closing price was $25.45 per unit.

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Since the closing date of the Encinal acquisition was July 1, 2006, our Statements of Consolidated Operations do not include any earnings from these assets prior to this date. Given the relative size of the Encinal acquisition to our other business combination transactions during 2006, the following table presents selected pro forma earnings information for the years ended December 31, 2006 and 2005 as if the Encinal acquisition had been completed on January 1, 2006 and 2005, respectively, instead of July 1, 2006. This information was prepared based on financial data available to us and reflects certain estimates and assumptions made by our management. Our pro forma financial information is not necessarily indicative of what our consolidated financial results would have been had the Encinal acquisition actually occurred on January 1, 2005. The amounts shown in the following table are in millions, except per unit amounts.

	For the Year Ended December 31,	
	2006	2005
Pro forma earnings data:		
Revenues	$14,066	$12,408
Costs and expenses	$13,228	$11,758
Operating income	$ 859	$ 664
Net income	$ 598	$ 418
Basic earnings per unit ("EPU"):		
Units outstanding, as reported	414	382
Units outstanding, pro forma	422	389
Basic EPU, as reported	$ 1.22	$ 0.91
Basic EPU, pro forma	$ 1.19	$ 0.89
Diluted EPU:		
Units outstanding, as reported	415	383
Units outstanding, pro forma	422	390
Diluted EPU, as reported	$ 1.22	$ 0.91
Diluted EPU, pro forma	$ 1.19	$ 0.89

Piceance Creek Acquisition. In December 2006, one of our affiliates, Enterprise Gas Processing, LLC, purchased a 100% interest in Piceance Creek Pipeline, LLC ("Piceance Creek"), for cash consideration of $100.0 million. Piceance Creek was wholly owned by EnCana Oil & Gas ("EnCana").

The assets of Piceance Creek consist of a recently constructed 48-mile natural gas gathering pipeline, the Piceance Creek Gathering System, located in the Piceance Basin of northwestern Colorado. The Piceance Creek Gathering System has a transportation capacity of 1.6 billion cubic feet per day ("Bcf/d") of natural gas and extends from a connection with EnCana's Great Divide Gathering System located near Parachute, Colorado, northward through the heart of the Piceance Basin to our 1.5 Bcf/d Meeker natural gas treating and processing complex. Connectivity to EnCana's Great Divide Gathering System will provide the Piceance Creek Gathering System with access to production from the southern portion of the Piceance basin, including production from EnCana's Mamm Creek field. The Piceance Creek Gathering System was placed in service in January 2007 and began transporting initial volumes of approximately 300 million cubic feet per day ("MMcf/d") of natural gas. Currently, we transport approximately 520 MMcf/d of natural gas volumes, with a significant portion of these volumes being produced by EnCana, one of the largest natural gas producers in the region. In conjunction with our acquisition of Piceance Creek, EnCana signed a long-term, fixed fee gathering agreement with us and dedicated significant production to the Piceance Creek Gathering System for the life of the associated lease holdings.

Other Transactions. In addition to the Encinal and Piceance Creek acquisitions, our business combinations during 2006 included the purchase of (i) an additional 8.2% ownership interest in Dixie for $12.9 million, (ii) all of the capital stock of an affiliated NGL marketing company located in Canada from related parties for $17.7 million (see Note 17) and (iii) a storage business in Flagstaff, Arizona for $0.7 million.

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2005 Transactions

Our expenditures for business combinations during the year ended December 31, 2005 were $326.6 million. In January 2005, we acquired indirect ownership interests in the Indian Springs Gathering System and Indian Springs natural gas processing plant for $74.9 million. In January and February 2005, we acquired an additional 46% of the ownership interests in Dixie for $68.6 million. In June 2005, we acquired additional indirect ownership interests in our Mid-America Pipeline System and Seminole Pipeline for $25.0 million. Also in June 2005, we acquired an additional 41.7% ownership interest in Belle Rose, which owns a NGL pipeline located in Louisiana, for $4.4 million. In July 2005, we purchased three underground NGL storage facilities and four propane terminals from Ferrellgas L.P. ("Ferrellgas") for $145.5 million in cash. Dixie and Belle Rose became consolidated subsidiaries of ours in 2005 as a result of our acquisition of additional ownership interests in these two entities.

Note 13. Intangible Assets and Goodwill

Identifiable Intangible Assets

The following table summarizes our intangible assets at the dates indicated:

	At December 31, 2007			At December 31, 2006		
	Gross Value	Accum. Amort.	Carrying Value	Gross Value	Accum. Amort.	Carrying Value
NGL Pipelines & Services:						
Shell Processing Agreement	$ 206,216	$ (78,252)	$127,964	$ 206,216	$ (67,204)	$ 139,012
Encinal gas processing customer relationship	127,119	(17,470)	109,649	127,119	(6,049)	121,070
STMA and GulfTerra NGL Business customer relationships	49,784	(17,537)	32,247	49,784	(12,980)	36,804
Pioneer gas processing contracts	37,752	(736)	37,016	37,752	—	37,752
Markham NGL storage contracts	32,664	(14,154)	18,510	32,664	(9,800)	22,864
Toca-Western contracts	31,229	(8,718)	22,511	31,229	(7,156)	24,073
Piceance Creek customer relationship	—	—	—	8,460	—	8,460
Other	35,261	(10,087)	25,174	35,370	(7,455)	27,915
Segment total	520,025	(146,954)	373,071	528,594	(110,644)	417,950
Onshore Natural Gas Pipelines & Services:						
San Juan Gathering System customer relationships	331,311	(73,087)	258,224	331,311	(52,318)	278,993
Petal & Hattiesburg natural gas storage contracts	100,499	(27,931)	72,568	100,499	(19,337)	81,162
Other	31,741	(8,381)	23,360	31,741	(5,747)	25,994
Segment total	463,551	(109,399)	354,152	463,551	(77,402)	386,149
Offshore Pipelines & Services:						
Offshore pipeline & platform customer relationships	205,845	(73,905)	131,940	205,845	(54,636)	151,209
Other	1,167	(49)	1,118	1,167	—	1,167
Segment total	207,012	(73,954)	133,058	207,012	(54,636)	152,376
Petrochemical Services:						
Mont Belvieu propylene fractionation contracts	53,000	(8,960)	44,040	53,000	(7,445)	45,555
Other	14,906	(2,227)	12,679	3,674	(1,749)	1,925
Segment total	67,906	(11,187)	56,719	56,674	(9,194)	47,480
Total all segments	$1,258,494	$(341,494)	$917,000	$1,255,831	$(251,876)	$1,003,955

We paid $11.2 million for certain air emission credits related to our Mont Belvieu complex in 2007. These items were recorded as intangible assets within our Petrochemical Services business segment.

The following table presents the amortization expense of our intangible assets by segment for the periods indicated:

	For the Year Ended December 31,		
	2007	2006	2005
NGL Pipelines & Services	$36,419	$31,159	$26,350
Onshore Natural Gas Pipelines & Services	31,997	33,447	35,080
Offshore Pipelines & Services	19,318	22,156	25,515
Petrochemical Services	1,993	1,993	1,993
Total all segments	$89,727	$88,755	$88,938

Based on information currently available, we estimate that amortization expense associated with existing intangible assets will approximate $86.3 million in 2008, $80.4 million in 2009, $75.8 million in 2010, $70.1 million in 2011 and $60.7 million in 2012.

In general, our intangible assets fall within two categories – contract-based intangible assets and customer relationships. Contract-based intangible assets represent commercial rights we acquired in connection with business combinations or asset purchases. Customer relationship intangible assets represent customer bases that we acquired in connection with business combinations and asset purchases. The values assigned to intangible assets are amortized to earnings using either (i) a straight-line approach or (ii) other methods that closely resemble the pattern in which the economic benefits of associated resource bases are estimated to be consumed or otherwise used, as appropriate.

We acquired $141.3 million of intangible assets during the year ended December 31, 2006, primarily attributable to customer relationships we acquired in connection with the Encinal acquisition. The $132.9 million of intangible assets we acquired in connection with the Encinal acquisition (see Note 12) represents the value we assigned to customer relationships, particularly the long-term relationship we now have with Lewis through natural gas processing and gathering arrangements. We recorded $127.1 million in our NGL Pipelines & Services segment associated with processing arrangements and $5.8 million in our Onshore Natural Gas Pipelines & Services segment associated with gathering arrangements. These intangible assets will be amortized to earnings over a 20-year life using methods that closely resemble the pattern in which we estimate the depletion of the underlying natural gas resources to occur.

We acquired numerous customer relationship and contract-based intangible assets in connection with the GulfTerra Merger. The customer relationship intangible assets represent the exploration and production, natural gas processing and NGL fractionation customer bases served by GulfTerra and the South Texas midstream assets at the time the merger was completed. The contract-based intangible assets represent the rights we acquired in connection with discrete contracts to provide storage services for natural gas and NGLs that GulfTerra had entered into prior to the merger.

The value we assigned to these customer relationships is being amortized to earnings using methods that closely resemble the pattern in which the economic benefits of the underlying oil and natural gas resource bases from which the customers produce are estimated to be consumed or otherwise used. Our estimate of the useful life of each resource base is based on a number of factors, including reserve estimates, the economic viability of production and exploration activities and other industry factors. This group of intangible assets primarily consists of the (i) Offshore Pipelines & Platforms customer relationships; (ii) San Juan Gathering System customer relationships; (iii) Texas Intrastate pipeline customer relationships; and (iv) STMA and GulfTerra NGL Business customer relationships.

The contract-based intangible assets we acquired in connection with the GulfTerra Merger are being amortized over the estimated useful life (or term) of each agreement, which we estimate to range from two to eighteen years. This group of intangible assets consists of the (i) Petal and Hattiesburg natural gas storage contracts and (ii) Markham NGL storage contracts.

The Shell Processing Agreement grants us the right to process Shell’s (or its assignee’s) current and future production within the state and federal waters of the Gulf of Mexico. We acquired this

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intangible asset in connection with our 1999 purchase of certain of Shell's midstream energy assets located along the Gulf Coast. The value of the Shell Processing Agreement is being amortized on a straight-line basis over the remainder of its initial 20-year contract term through 2019.

Goodwill

Goodwill represents the excess of the purchase price of an acquired business over the amounts assigned to assets acquired and liabilities assumed in the transaction. Goodwill is not amortized; however, it is subject to annual impairment testing. The following table summarizes our goodwill amounts by segment at the dates indicated:

	At December 31,	
	2007	**2006**
NGL Pipelines & Services		
GulfTerra Merger	$ 23,854	$ 23,854
Acquisition of Indian Springs natural gas processing business	13,162	13,162
Encinal acquisition	95,280	95,166
Other	21,410	20,413
Onshore Natural Gas Pipelines & Services		
GulfTerra Merger	279,956	279,956
Acquisition of Indian Springs natural gas gathering business	2,165	2,165
Offshore Pipelines & Services		
GulfTerra Merger	82,135	82,135
Petrochemical Services		
Acquisition of Mont Belvieu propylene fractionation business	73,690	73,690
Total	$591,652	$590,541

Goodwill recorded in connection with the GulfTerra Merger can be attributed to our belief (at the time the merger was consummated) that the combined partnerships would benefit from the strategic location of each partnership's assets and the industry relationships that each possessed. In addition, we expected that various operating synergies could develop (such as reduced general and administrative costs and interest savings) that would result in improved financial results for the merged entity. Based on miles of pipelines, GulfTerra was one of the largest natural gas gathering and transportation companies in the United States, serving producers in the central and western Gulf of Mexico and onshore in Texas and New Mexico. These regions offer us significant growth potential through the acquisition and construction of additional pipelines, platforms, processing and storage facilities and other midstream energy infrastructure.

In 2006, the only significant change in goodwill was the recording of $95.2 million in connection with our preliminary purchase price allocation for the Encinal acquisition. Management attributes this goodwill to potential future benefits we may realize from our other south Texas processing and NGL businesses as a result of acquiring the Encinal business. Specifically, our acquisition of the long-term dedication rights associated with the Encinal business is expected to add value to our south Texas processing facilities and related NGL businesses due to increased volumes. The Encinal goodwill is recorded as part of the NGL Pipelines & Services business segment due to management's belief that such future benefits will accrue to businesses classified within this segment.

The remainder of our goodwill amounts is associated with prior acquisitions, principally that of our purchase of a propylene fractionation business in February 2002 and our acquisition of indirect ownership interests in the Indian Springs natural gas gathering and processing business in January 2005.

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Note 14. Debt Obligations

Our consolidated debt obligations consisted of the following at the dates indicated:

	At December 31, 2007	At December 31, 2006
EPO senior debt obligations:		
Multi-Year Revolving Credit Facility, variable rate, due November 2012 (1)	$ 725,000	$ 410,000
Pascagoula MBFC Loan, 8.70% fixed-rate, due March 2010	54,000	54,000
Senior Notes B, 7.50% fixed-rate, due February 2011	450,000	450,000
Senior Notes C, 6.375% fixed-rate, due February 2013	350,000	350,000
Senior Notes D, 6.875% fixed-rate, due March 2033	500,000	500,000
Senior Notes E, 4.00% fixed-rate, due October 2007 (2)	—	500,000
Senior Notes F, 4.625% fixed-rate, due October 2009	500,000	500,000
Senior Notes G, 5.60% fixed-rate, due October 2014	650,000	650,000
Senior Notes H, 6.65% fixed-rate, due October 2034	350,000	350,000
Senior Notes I, 5.00% fixed-rate, due March 2015	250,000	250,000
Senior Notes J, 5.75% fixed-rate, due March 2035	250,000	250,000
Senior Notes K, 4.950% fixed-rate, due June 2010	500,000	500,000
Senior Notes L, 6.30% fixed-rate, due September 2017	800,000	—
Petal GO Zone Bonds, variable rate, due August 2034	57,500	—
Duncan Energy Partners' debt obligation:		
$300 Million Revolving Credit Facility, variable rate, due February 2011	200,000	—
Dixie Revolving Credit Facility, variable rate, due June 2010	10,000	10,000
Other, 8.75% fixed-rate, due June 2010 (3)	—	5,068
Total principal amount of senior debt obligations	5,646,500	4,779,068
EPO Junior Subordinated Notes A, due August 2066	550,000	550,000
EPO Junior Subordinated Notes B, due January 2068	700,000	—
Total principal amount of senior and junior debt obligations	6,896,500	5,329,068
Other, including unamortized discounts and premiums and changes in fair value (4)	9,645	(33,478)
Long-term debt	$6,906,145	$5,295,590
Standby letters of credit outstanding	$ 1,100	$ 49,858

(1) In November 2007, EPO executed an amended and restated revolving credit agreement governing its Multi-Year Revolving Credit Facility. This new credit agreement increases the capacity from $1.25 billion to $1.75 billion and extends the maturity date of amounts borrowed under EPO's Multi-Year Revolving Credit Facility from October 2011 to November 2012.

(2) In accordance with SFAS 6, "Classification of Short-Term Obligations Expected to be Refinanced," long-term and current maturities of debt reflects the classification of such obligations at December 31, 2006. With respect to Senior Notes E, EPO repaid this note in October 2007, using cash and available credit capacity under its then $1.25 billion Multi-Year Revolving Credit Facility.

(3) Represents remaining debt obligations assumed in connection with the GulfTerra Merger, which were redeemed in the fourth quarter of 2007.

(4) The December 31, 2007 amount includes an asset of $14.8 million related to fair value hedges offset by a net $5.2 million in unamortized discounts. The December 31, 2006 amount includes a liability of $29.1 million related to fair value hedges and a net $4.4 million in unamortized discounts.

Letters of credit

At December 31, 2007, we had $1.1 million of standby letters outstanding under Duncan Energy Partners' Revolving Credit Facility. At December 31, 2006, we had $49.9 million in standby letters of credit outstanding, all of which were issued under EPO's Multi-Year Revolving Credit Facility. As of February 1, 2008, our standby letters of credit outstanding were $1.1 million under Duncan Energy Partners' Revolving Credit Facility.

Parent-Subsidiary guarantor relationships

We act as guarantor of the debt obligations of EPO with the exception of the Dixie revolving credit facility and the senior subordinated notes we assumed in connection with the GulfTerra Merger. If EPO were to default on any debt we guarantee, we would be responsible for full repayment of that obligation. We do not act as guarantor of the debt obligations of Duncan Energy Partners.

EPO's senior indebtedness is structurally subordinated to and ranks junior in right of payment to the indebtedness of GulfTerra and Dixie. This subordination feature exists only to the extent that the repayment of debt incurred by GulfTerra and Dixie is dependent upon the assets and operations of these two entities. The Dixie revolving credit facility is an unsecured obligation of Dixie (of which we own 74.2% of its capital stock). The senior subordinated notes of GulfTerra are unsecured obligations of GulfTerra (of which we own 100% of its limited and general partnership interests).

EPO's debt obligations

Multi-Year Revolving Credit Facility. In November 2007, EPO executed an amended and restated Multi-Year Revolving Credit Facility totaling $1.75 billion, which replaced an existing $1.25 billion multi-year revolving credit agreement. Amounts borrowed under the amended and restated credit agreement mature in November 2012, although EPO is permitted, 30 to 60 days before the maturity date in effect, to convert the principal balance of the revolving loans then outstanding into a non-revolving, one-year term loan (the "term-out option"). There is no sublimit on the amount of standby letters of credit that can be outstanding under the amended facility. EPO's borrowings under this agreement are unsecured general obligations that are non-recourse to EPGP. We have guaranteed repayment of amounts due under this revolving credit agreement through an unsecured guarantee.

As defined by the credit agreement, variable interest rates charged under this facility bear interest at a Eurodollar rate plus an applicable margin. In addition, EPO is required to pay a quarterly facility fee on each lender's commitment irrespective of commitment usage.

The applicable margins will be increased by 0.100% per annum for each day that the total outstanding loans and letter of credit obligations under the facility exceeds fifty percent of the total lender commitments. Also, upon the conversion of the revolving loans to term loans pursuant to the term-out option described above, the applicable margin will increase by 0.125% per annum and, if immediately prior to such conversion, the total amount of outstanding loans and letter of credit obligations under the facility exceeds fifty percent of the total lender commitments, the applicable margin with respect to the term loans will increase by an additional 0.10% per annum.

EPO may increase the amount that may be borrowed under the facility, without the consent of the lenders, by an amount not exceeding $500.0 million by adding to the facility one or more new lenders and/or requesting that the commitments of existing lenders be increased, although none of the existing lenders has agreed to or is obligated to increase its existing commitment. EPO may request unlimited one-year extensions of the maturity date by delivering a written request to the administrative agent, but any such extension shall be effective only if consented to by the required lenders in their sole discretion.

The Multi-Year Revolving Credit Facility contains various covenants related to EPO's ability to incur certain indebtedness; grant certain liens; enter into certain merger or consolidation transactions; and make certain investments. The loan agreement also requires EPO to satisfy certain financial covenants at the end of each fiscal quarter. The credit agreement also restricts EPO's ability to pay cash distributions to us if a default or an event of default (as defined in the credit agreement) has occurred and is continuing at the time such distribution is scheduled to be paid.

Pascagoula MBFC Loan. In connection with the construction of our Pascagoula, Mississippi natural gas processing plant in 2000, EPO entered into a ten-year fixed-rate loan with the Mississippi Business Finance Corporation ("MBFC"). This loan is subject to a make-whole redemption right and is guaranteed by us through an unsecured and unsubordinated guarantee. The Pascagoula MBFC Loan contains certain covenants including the maintenance of appropriate levels of insurance on the Pascagoula facility.

The indenture agreement for this loan contains an acceleration clause whereby if EPO's credit rating by Moody's declines below Baa3 in combination with our credit rating at Standard & Poor's declining below BBB-, the $54 million principal balance of this loan, together with all accrued and unpaid interest, would become immediately due and payable 120 days following such event. If such an event occurred, we would have to either redeem the Pascagoula MBFC Loan or provide an alternative credit agreement to support our obligation under this loan.

Senior Notes B through L. These fixed-rate notes are unsecured obligations of EPO and rank equally with its existing and future unsecured and unsubordinated indebtedness. They are senior to any future subordinated indebtedness. EPO's borrowings under these notes are non-recourse to EPGP. We have guaranteed repayment of amounts due under these notes through an unsecured and unsubordinated guarantee. Our guarantee of such notes is non-recourse to EPGP. The Senior Notes are subject to make-whole redemption rights and were issued under indentures containing certain covenants, which generally restrict EPO's ability, with certain exceptions, to incur debt secured by liens and engage in sale and leaseback transactions.

EPO used net proceeds from its issuance of Senior Notes L to temporarily reduce indebtedness outstanding under its Multi-Year Revolving Credit Facility and for general partnership purposes. In October 2007, EPO used borrowing capacity under its Multi-Year Revolving Credit Facility to repay its $500.0 million Senior Notes E.

Petal GO Zone Bonds. In August 2007, Petal borrowed $57.5 million from the MBFC pursuant to a loan agreement and promissory note between Petal and the MBFC to pay a portion of the costs of certain natural gas storage facilities located in Petal, Mississippi. The promissory note between Petal and MBFC is guaranteed by EPO and supported by a letter of credit issued by Petal. On the same date, the MBFC issued $57.5 million in Gulf Opportunity Zone Tax-Exempt ("GO Zone") bonds to various third parties. A portion of the GO Zone bond proceeds are being held by a third party trustee and reflected as a component of other assets on our balance sheet. The remaining proceeds held by the trustee will be released to us as we spend capital to complete the construction of the natural gas storage facilities. At December 31, 2007, $17.9 million of the GO Zone bond proceeds remained held by the third party trustee. The promissory note and the GO Zone bonds have identical terms including floating interest rates and maturities of twenty-seven years. The bonds and the associated tax incentives are authorized under the Mississippi Business Finance Act and the Gulf Opportunity Zone Act of 2005.

Petal MBFC Loan. In August 2007, Petal Gas Storage L.L.C. ("Petal"), a wholly owned subsidiary of EPO, entered into a loan agreement and a promissory note with the MBFC under which Petal may borrow up to $29.5 million. On the same date, the MBFC issued taxable bonds to EPO in the maximum amount of $29.5 million. As of December 31, 2007, there was $8.9 million outstanding under the loan and the bonds. EPO will make advances on the bonds to the MBFC and the MBFC will in turn make identical advances to Petal under the promissory note. The promissory note and the taxable bonds have identical terms including fixed interest rates of 5.90% and maturities of fifteen years. The bonds and the associated tax incentives are authorized under the Mississippi Business Finance Act. Petal may prepay on the promissory note without penalty, and thus cause the bonds to be redeemed, any time after one year from their date of issue. The loan and bonds are netted in preparing our consolidated balance sheet, as well the related interest expense and income amounts are netted in preparing our consolidated income statement.

Junior Notes A. In the third quarter of 2006, EPO sold $550.0 million in principal amount of fixed/floating, unsecured, long-term subordinated notes due 2066 ("Junior Notes A"). EPO used the proceeds from this subordinated debt to temporarily reduce borrowings outstanding under its Multi-Year Revolving Credit Facility and for general partnership purposes. EPO's payment obligations under Junior Notes A are subordinated to all of its current and future senior indebtedness (as defined in the related indenture agreement). We guaranteed EPO's repayment of amounts due under Junior Notes A through an unsecured and subordinated guarantee.

The indenture agreement governing Junior Notes A allows EPO to defer interest payments on one or more occasions for up to ten consecutive years, subject to certain conditions. The indenture agreement also provides that, unless (i) all deferred interest on Junior Notes A has been paid in full as of the most recent interest payment date, (ii) no event of default under the indenture agreement has occurred and is continuing and (iii) we are not in default of our obligations under related guarantee agreements, neither we nor EPO cannot declare or make any distributions to any of our respective equity securities or make any

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payments on indebtedness or other obligations that rank pari passu with or are subordinated to the Junior Notes A.

The Junior Notes A bear interest at a fixed annual rate of 8.375% from July 2006 to August 2016, payable semi-annually in arrears in February and August of each year, which commenced in February 2007. After August 2016, the Junior Notes A will bear variable rate interest at an annual rate equal to the 3-month LIBOR rate for the related interest period plus 3.708%, payable quarterly in arrears in February, May, August and November of each year commencing in November 2016. Interest payments may be deferred on a cumulative basis for up to ten consecutive years, subject to the certain provisions. The Junior Notes A mature in August 2066 and are not redeemable by EPO prior to August 2016 without payment of a make-whole premium.

In connection with the issuance of Junior Notes A, EPO entered into a Replacement Capital Covenant in favor of the covered debt holders (as defined in the underlying documents) pursuant to which EPO agreed for the benefit of such debt holders that it would not redeem or repurchase such junior notes unless such redemption or repurchase is made using proceeds from the of issuance of certain securities.

Junior Notes B. EPO sold $700 million in principal amount of fixed/floating, unsecured, long-term subordinated notes due January 2068 ("Junior Notes B") during the second quarter of 2007. EPO used the proceeds from this subordinated debt to temporarily reduce borrowings outstanding under its Multi-Year Revolving Credit Facility and for general partnership purposes. EPO's payment obligations under Junior Notes B are subordinated to all of its current and future senior indebtedness (as defined in the Indenture Agreement). We have guaranteed repayment of amounts due under Junior Notes B through an unsecured and subordinated guarantee.

The indenture agreement governing Junior Notes B allows EPO to defer interest payments on one or more occasions for up to ten consecutive years subject to certain conditions. During any period in which interest payments are deferred and subject to certain exceptions, neither we nor EPO can declare or make any distributions to any of our respective equity securities or make any payments on indebtedness or other obligations that rank pari passu with or are subordinate to Junior Notes B. Junior Notes B rank pari passu with Junior Notes A.

The Junior Notes B will bear interest at a fixed annual rate of 7.034% through January 15, 2018, payable semi-annually in arrears in January and July of each year, commencing in January 2008. After January 2018, the Junior Notes B will bear variable rate interest at the greater of (1) the sum of the 3-month LIBOR for the related interest period plus a spread of 268 basis points or (2) 7.034% per annum, payable quarterly in arrears in January, April, July and October of each year commencing in April 2018. Interest payments may be deferred on a cumulative basis for up to ten consecutive years, subject to certain provisions. The Junior Notes B mature in January 2068 and are not redeemable by EPO prior to January 2018 without payment of a make-whole premium.

In connection with the issuance of Junior Notes B, we and EPO entered into a Replacement Capital Covenant in favor of the covered debt holders (as named therein) pursuant to which we and EPO agreed for the benefit of such debt holders that neither we nor EPO would redeem or repurchase such junior notes on or before January 15, 2038, unless such redemption or repurchase is made from the proceeds of issuance of certain securities.

Duncan Energy Partners' debt obligation

We consolidate the debt of Duncan Energy Partners with that of our own; however, we do not have the obligation to make interest payments or debt payments with respect to the debt of Duncan Energy Partners.

Duncan Energy Partners entered into a $300.0 million revolving credit facility, all of which may be used for letters of credit, with a $30.0 million sublimit for Swingline loans. Letters of credit outstanding under this facility reduce the amount available for borrowings. At the closing of its initial public offering, Duncan Energy Partners made its initial borrowing of $200.0 million under the facility to fund a $198.9 million cash distribution to EPO and the remainder to pay debt issuance costs. At December 31, 2007, the principal balance outstanding under this facility was $200.0 million.

This credit facility matures in February 2011 and will be used by Duncan Energy Partners in the future to fund working capital and other capital requirements and for general partnership purposes. Duncan Energy Partners may make up to two requests for one-year extensions of the maturity date (subject to certain restrictions). The revolving credit facility is available to pay distributions upon the initial contribution of assets to Duncan Energy Partners, fund working capital, make acquisitions and provide payment for general purposes. Duncan Energy Partners can increase the revolving credit facility, without consent of the lenders, by an amount not to exceed $150.0 million by adding to the facility one or more new lenders and/or increasing the commitments of existing lenders. No existing lender is required to increase its commitment, unless it agrees to do so in its sole discretion.

This revolving credit facility offers the following unsecured loans, each having different interest requirements: (i) LIBOR loans bear interest at a rate per annum equal to LIBOR plus the applicable LIBOR margin (as defined in the credit agreement), (ii) Base Rate loans bear interest at a rate per annum equal to the higher of (a) the rate of interest publicly announced by the administrative agent, Wachovia Bank, National Association, as its Base Rate and (b) 0.5% per annum above the Federal Funds Rate in effect on such date and (iii) Swingline loans bear interest at a rate per annum equal to LIBOR plus an applicable LIBOR margin.

The Duncan Energy Partners' credit facility contains certain financial and other customary covenants. Also, if an event of default exists under the credit agreement, the lenders will be able to accelerate the maturity date of amounts borrowed under the credit agreement and exercise other rights and remedies.

Dixie Revolving Credit Facility

As a result of acquiring a controlling interest in Dixie in February 2005, we began consolidating the financial statements of Dixie with those of our own. In accordance with GAAP, we consolidate the debt of Dixie with that of our own; however we do not have the obligation to make interest or debt payments with respect to Dixie's debt. Dixie's debt obligations consist of a senior, unsecured revolving credit facility having a borrowing capacity of $28.0 million. The maturity date of this facility was extended from June 2007 to June 2010 in August 2006.

As defined in the Dixie credit agreement, variable interest rates charged under this facility generally bear interest, at our election at the time of each borrowing, at either (i) a Eurodollar rate plus an applicable margin or (ii) the greater of (a) the Prime Rate or (b) the Federal Funds Rate plus $^1/_2$%.

The credit agreement contains various covenants related to Dixie's ability to incur certain indebtedness; grant certain liens; enter into merger transactions; and make certain investments. The loan agreement also requires Dixie to satisfy a minimum net worth financial covenant. The revolving credit agreement restricts Dixie's ability to pay cash dividends to us and its other stockholders if a default or an event of default (as defined in the credit agreement) has occurred and its continuing at the time such dividend is scheduled to be paid.

Canadian Debt Obligations

In May 2007, Canadian Enterprise Gas Products, Ltd. ("Canadian Enterprise"), a wholly-owned subsidiary of EPO, entered into a $30.0 million Canadian revolving credit facility with The Bank of Nova Scotia. The credit facility, which includes the issuance of letters of credit, matures in October 2011. Letters of credit outstanding under this facility reduce the amount available for borrowings.

Borrowings may be made in Canadian or U.S. dollars. Canadian denominated borrowings may be comprised of Canadian Prime Rate ("CPR") loans or Bankers' Acceptances and U.S. denominated borrowings may be comprised of Alternative Base Rate ("ABR") or Eurodollar loans, each having different interest rate requirements. CPR loans bear interest at a rate determined by reference to the Canadian Prime Rate. ABR loans bear interest at a rate determined by reference to an alternative base rate as defined in the credit agreement. Eurodollar loans bear interest at a rate determined by the LIBOR plus an applicable rate as defined in the credit agreement. Bankers' Acceptances carry interest at the rate for Canadian bankers' acceptances plus an applicable rate as defined in the credit agreement.

The credit facility contains customary covenants and events of default. The restrictive covenants limit Canadian Enterprise from materially changing the nature of its business or operations, dissolving, or completing mergers. A continuing event of default would accelerate the maturity of amounts borrowed under the credit facility. The obligations under the credit facility are guaranteed by EPO. As of December 31, 2007, there were no debt obligations outstanding under this credit facility.

Covenants

We are in compliance with the covenants of our consolidated debt agreements at December 31, 2007 and 2006.

Information regarding variable interest rates paid

The following table shows the range of interest rates paid and weighted-average interest rate paid on our consolidated variable-rate debt obligations during the year ended December 31, 2007.

	Range of interest rates paid	Weighted-average interest rate paid
EPO's Multi-Year Revolving Credit Facility	5.10% to 8.25%	5.78%
Duncan Energy Partners' Revolving Credit Facility	5.52% to 6.42%	6.23%
Dixie Revolving Credit Facility	5.50% to 5.67%	5.63%
Canadian Enterprise Revolving Credit Facility	5.01% to 5.82%	5.68%
Petal GO Zone Bonds	3.11% to 4.15%	3.56%

Consolidated debt maturity table

The following table presents the scheduled maturities of principal amounts of our debt obligations for the next five years and in total thereafter.

2008	$ —
2009	500,000
2010	591,840
2011	650,000
2012	697,160
Thereafter	4,457,500
Total scheduled principal payments	$6,896,500

In accordance with SFAS 6, long-term and current maturities of debt reflect the classification of such obligations at December 31, 2006. With respect to the $500.0 million in principal that was due under Senior Notes E in October 2007, EPO repaid this note in October 2007 using cash and available credit capacity under its Multi-Year Revolving Credit Facility. The preceding table and our Consolidated Balance Sheet at December 31, 2006 reflect this ability to refinance.

Debt Obligations of Unconsolidated Affiliates

We have two unconsolidated affiliates with long-term debt obligations. The following table shows (i) our ownership interest in each entity at December 31, 2007, (ii) total debt of each unconsolidated affiliate at December 31, 2007 (on a 100% basis to the affiliate) and (iii) the corresponding scheduled maturities of such debt.

	Our Ownership Interest	Total	Scheduled Maturities of Debt					
			2008	2009	2010	2011	2012	After 2012
Poseidon	36%	$ 91,000	$ —	$ —	$ —	$91,000	$—	$—
Evangeline	49.5%	20,650	5,000	5,000	10,650	—	—	—
Total		$111,650	$5,000	$5,000	$10,650	$91,000	$—	$—

The credit agreements of our unconsolidated affiliates contain various affirmative and negative covenants, including financial covenants. These businesses were in compliance with such covenants at December 31, 2007. The credit agreements of our unconsolidated affiliates restrict their ability to pay cash dividends if a default or an event of default (as defined in each credit agreement) has occurred and is continuing at the time such dividend is scheduled to be paid. Cameron Highway repaid its debt obligations during the second quarter of 2007 using pro rata capital contributions from EPO and its joint venture partner in Cameron Highway.

The following information summarizes significant terms of the debt obligations of our unconsolidated affiliates at December 31, 2007:

Poseidon. Poseidon has $91.0 million outstanding under its $150.0 million revolving credit facility that matures in May 2011. Interest rates charged under this revolving credit facility are variable and depend on the ratio of Poseidon’s total debt to its earnings before interest, taxes, depreciation and amortization. This credit agreement is secured by substantially all of Poseidon’s assets. The variable interest rates charged on this debt at December 31, 2007 and 2006 were 6.62% and 6.68%, respectively.

Evangeline. At December 31, 2007, short and long-term debt for Evangeline consisted of (i) $13.2 million in principal amount of 9.90% fixed-rate Series B senior secured notes due December 2010 and (ii) a $7.5 million subordinated note payable. The Series B senior secured notes are collateralized by Evangeline’s property, plant and equipment; proceeds from a gas sales contract; and by a debt service reserve requirement. Scheduled principal repayments on the Series B notes are $5.0 million annually through 2009 with a final repayment in 2010 of approximately $3.2 million. The trust indenture governing the Series B notes contains covenants such as requirements to maintain certain financial ratios.

Evangeline incurred the subordinated note payable as a result of its acquisition of a contract-based intangible asset in the 1990s. This note is subject to a subordination agreement which prevents the repayment of principal and accrued interest on the note until such time as the Series B noteholders are either fully cash secured through debt service accounts or have been completely repaid. Variable rate interest accrues on the subordinated note at a Eurodollar rate plus $^{1}/_{2}$%. The variable interest rates charged on this note at December 31, 2007 and 2006 were 5.88% and 6.08%, respectively. Accrued interest payable related to the subordinated note was $9.1 million and $7.9 million at December 31, 2007 and 2006, respectively.

Note 15. Partners’ Equity and Distributions

Our common units represent limited partner interests, which give the holders thereof the right to participate in distributions and to exercise the other rights or privileges available to them under our Fifth Amended and Restated Agreement of Limited Partnership (together with all amendments thereto, the "Partnership Agreement"). We are managed by our general partner, EPGP.

In accordance with the Partnership Agreement, capital accounts are maintained for our general partner and limited partners. The capital account provisions of our Partnership Agreement incorporate principles established for U.S. Federal income tax purposes and are not comparable to the equity accounts reflected under GAAP in our consolidated financial statements.

Our Partnership Agreement sets forth the calculation to be used in determining the amount and priority of cash distributions that our limited partners and general partner will receive. The Partnership Agreement also contains provisions for the allocation of net earnings and losses to our limited partners and general partner. For purposes of maintaining partner capital accounts, the Partnership Agreement specifies that items of income and loss shall be allocated among the partners in accordance with their respective percentage interests. Normal income and loss allocations according to percentage interests are done only after giving effect to priority earnings allocations in an amount equal to incentive cash distributions allocated to our general partner.

In August 2005, we revised our Partnership Agreement to allow EPGP, at its discretion, to elect not to make its proportionate capital contributions to us in connection with our issuance of limited partner interests, in which case its 2% general partner interest would be proportionately reduced. At the time of such offerings, EPGP has historically contributed cash to us to maintain its 2% general partner interest. EPGP made such cash contributions to us during the years ended December 31, 2007 and 2006. If EPGP exercises this option in the future, the amount of earnings we allocate to it and the cash distributions it receives from us will be reduced accordingly. If this occurs, EPGP can, under certain conditions, restore its full 2% general partner interest by making additional cash contributions to us.

Equity offerings and registration statements

In general, the Partnership Agreement authorizes us to issue an unlimited number of additional limited partner interests and other equity securities for such consideration and on such terms and conditions as may be established by EPGP in its sole discretion (subject, under certain circumstances, to the approval of our unitholders).

In August 2007, we filed a universal shelf registration statement with the SEC that allows us to issue an unlimited amount of debt and equity securities.

During 2003, we instituted a distribution reinvestment plan ("DRIP"). In April 2007, we filed a registration statement with the SEC authorizing the issuance of up to 25,000,000 common units in connection with the DRIP. The DRIP provides unitholders of record and beneficial owners of our common units a voluntary means by which they can increase the number of common units they own by reinvesting the quarterly cash distributions they would otherwise receive into the purchase of additional common units. A total of 16,102,737 common units have been issued under this registration statement through December 31, 2007.

We also have a registration statement on file related to our employee unit purchase plan, under which we can issue up to 1,200,000 common units. Under this plan, employees of EPCO can purchase our common units at a 10% discount through payroll deductions. A total of 495,661 common units have been issued to employees under this plan through December 31, 2007.

The following table reflects the number of common units issued and the net proceeds received from underwritten and other common unit offerings completed during the years ended December 31, 2007, 2006 and 2005:

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	Net Proceeds from Sale of Common Units			
	Number of common units issued	Contributed by Limited Partners	Contributed by General Partner	Total Net Proceeds
Fiscal 2005:				
Underwritten offerings	21,250,000	$544,347	$11,109	$555,456
Other offerings, primarily DRIP	2,729,740	68,269	1,393	69,662
Total 2005	23,979,740	$612,616	$12,502	$625,118
Fiscal 2006:				
Underwritten offerings	31,050,000	$735,819	$15,003	$750,822
Other offerings, primarily DRIP	3,774,649	95,006	1,940	96,946
Total 2006	34,824,649	$830,825	$16,943	$847,768
Fiscal 2007:				
Other offerings, primarily DRIP	2,056,615	$ 60,445	$ 1,232	$ 61,677
Total 2007	2,056,615	$ 60,445	$ 1,232	$ 61,677

Other offerings primarily represent the issuance of common units under our distribution reinvestment plan. Net proceeds received from our underwritten offerings completed during 2005 were generally used to repay an interim credit facility related to the GulfTerra Merger and to temporarily reduce borrowings outstanding under EPO’s Multi-Year Revolving Credit Facility. Net proceeds from our other offerings were used for general partnership purposes.

Net proceeds received from our underwritten and other offerings completed during 2006 were used to temporarily reduce borrowings outstanding under EPO’s Multi-Year Revolving Credit Facility and for general partnership purposes.

Net proceeds received from our other offerings completed during 2007 were used to temporarily reduce borrowings outstanding under EPO’s Multi-Year Revolving Credit Facility and for general partnership purposes.

Summary of Changes in Outstanding Units

The following table summarizes changes in our outstanding units since December 31, 2004:

	Common Units	Restricted Common Units	Treasury Units
Balance, December 31, 2004	364,297,340	488,525	427,200
Units issued in connection with underwritten offerings	21,250,000	—	—
Units issued in connection with other offerings	2,729,740	—	—
Units issued in connection with equity-based awards	826,000	362,011	—
Forfeiture of restricted units	—	(92,448)	—
Conversion of restricted units to common units	6,484	(6,484)	—
Cancellation of treasury units	—	—	(427,200)
Balance, December 31, 2005	389,109,564	751,604	—
Units issued in connection with underwritten offerings	31,050,000	—	—
Units issued in connection with other offerings	3,774,649	—	—
Units issued in connection with equity-based awards	211,000	466,400	—
Forfeiture of restricted units	—	(70,631)	—
Conversion of restricted units to common units	42,136	(42,136)	—
Units issued in connection with Encinal acquisition	7,115,844	—	—
Balance, December 31, 2006	431,303,193	1,105,237	—
Units issued in connection with other offerings	2,056,615	—	—
Units issued in connection with equity-based awards	244,071	738,040	—
Forfeiture or settlement of restricted units	—	(149,853)	—
Conversion of restricted units to common units	4,884	(4,884)	—
Balance, December 31, 2007	433,608,763	1,688,540	—

Treasury Units. In 2000, we and a consolidated trust (the "1999 Trust") were authorized by EPGP to repurchase up to 2,000,000 publicly-held common units under an announced buy-back program. The repurchases would be made during periods of temporary market weakness at price levels that would be accretive to our remaining unitholders. After deducting for repurchases under the program in prior periods, we and the 1999 Trust could repurchase up to 618,400 common units at December 31, 2005. We cancelled our 427,200 treasury units in 2005.

Summary of Changes in Limited Partners' Equity

The following table details the changes in limited partners' equity since December 31, 2004:

	Common units	Restricted Common units	Total
Balance, December 31, 2004	$5,204,940	$ 12,327	$5,217,267
Net income	347,948	564	348,512
Operating leases paid by EPCO	2,067	3	2,070
Cash distributions to partners	(629,629)	(931)	(630,560)
Unit option reimbursements to EPCO	(9,199)	—	(9,199)
Net proceeds from sales of common units	612,616	—	612,616
Proceeds from exercise of unit options	21,374	—	21,374
Issuance of restricted units	—	9,478	9,478
Vesting of restricted units	143	(143)	—
Forfeiture of restricted units	—	(2,663)	(2,663)
Amortization of equity-based awards	1,355	3	1,358
Cancellation of treasury units	(8,915)	—	(8,915)
Balance, December 31, 2005	5,542,700	18,638	5,561,338
Net income	502,969	1,187	504,156
Operating leases paid by EPCO	2,062	5	2,067
Cash distributions to partners	(738,004)	(1,628)	(739,632)
Unit option reimbursements to EPCO	(1,818)	—	(1,818)
Net proceeds from sales of common units	830,825	—	830,825
Common units issued in connection with Encinal acquisition	181,112	—	181,112
Proceeds from exercise of unit options	5,601		5,601
Amortization of equity-based awards	2,209	6,073	8,282
Change in accounting method for equity Awards (see Note 5)	(896)	(14,919)	(15,815)
Acquisition-related disbursement of cash	(6,183)	(16)	(6,199)
Balance, December 31, 2006	6,320,577	9,340	6,329,917
Net income	416,323	1,405	417,728
Operating leases paid by EPCO	2,056	7	2,063
Cash distributions to partners	(831,155)	(2,638)	(833,793)
Unit option reimbursements to EPCO	(2,999)	—	(2,999)
Net proceeds from sales of common units	60,445	—	60,445
Proceeds from exercise of unit options	7,549	—	7,549
Repurchase of restricted units and options	(512)	(1,056)	(1,568)
Amortization of equity-based awards	4,663	8,890	13,553
Balance, December 31, 2007	$5,976,947	$ 15,948	$5,992,895

In October 2006, we acquired all of the capital stock of an affiliated NGL marketing company located in Canada from EPCO and Dan L. Duncan for $17.7 million in cash. The amount we paid for this business exceeded the carrying values of the assets acquired and liabilities assumed from this related party (which is under common control with us) by $6.3 million, of which $6.2 million was allocated to limited partners and $0.1 million to our general partner. The excess of the acquisition price over the net book value of this business at the time of acquisition is treated as a deemed distribution to our owners and presented as an "Acquisition-related disbursement of cash" in our Statement of Partners' Equity for the year ended December 31, 2006. The total purchase price is a component of "Cash used for business combinations" as presented in our Statement of Consolidated Cash Flows for the year ended December 31, 2006 (see Note 12).

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Distributions to Partners

The percentage interest of EPGP in our quarterly cash distributions is increased after certain specified target levels of quarterly distribution rates are met. At current distribution rates, we are in the highest tier of such incentive targets. EPGP's quarterly incentive distribution thresholds are as follows:

- 2% of quarterly cash distributions up to $0.253 per unit;
- 15% of quarterly cash distributions from $0.253 per unit up to $0.3085 per unit; and
- 25% of quarterly cash distributions that exceed $0.3085 per unit.

We paid incentive distributions of $107.4 million, $86.7 million and $63.9 million to EPGP during the years ended December 31, 2007, 2006 and 2005, respectively.

The following table presents our declared quarterly cash distribution rates per unit since the first quarter of 2006 and the related record and distribution payment dates. The quarterly cash distribution rates per unit correspond to the fiscal quarters indicated. Actual cash distributions are paid within 45 days after the end of such fiscal quarter.

	Distribution per Unit	Record Date	Payment Date
2006			
1st Quarter	$0.4450	Apr. 28, 2006	May 10, 2006
2nd Quarter	$0.4525	Jul. 31, 2006	Aug. 10, 2006
3rd Quarter	$0.4600	Oct. 31, 2006	Nov. 8, 2006
4th Quarter	$0.4675	Jan. 31, 2007	Feb. 8, 2007
2007			
1st Quarter	$0.4750	Apr. 30, 2007	May 10, 2007
2nd Quarter	$0.4825	Jul. 31, 2007	Aug. 9, 2007
3rd Quarter	$0.4900	Oct. 31, 2007	Nov. 8, 2007
4th Quarter	$0.5000	Jan. 31, 2008	Feb. 7, 2008

Accumulated Other Comprehensive Income

The following table presents the components of accumulated other comprehensive income at the dates indicated:

	At December 31, 2007	At December 31, 2006
Commodity financial instruments (1)	$(21,619)	$ (3,622)
Interest rate financial instruments (1)	34,980	26,034
Foreign currency hedges (1)	1,308	—
Foreign currency translation adjustment (1)	1,200	(807)
Pension and postretirement benefit plans (2)	588	(464)
Total accumulated other comprehensive income	$ 16,457	$21,141

(1) See Note 2 for additional information regarding these components of accumulated other comprehensive income.

(2) See Note 6 for additional information regarding pension and postretirement benefit plans.

Note 16. Business Segments

We have four reportable business segments: NGL Pipelines & Services; Onshore Natural Gas Pipelines & Services; Offshore Pipelines & Services; and Petrochemical Services. Our business segments are generally organized and managed according to the type of services rendered (or technologies employed) and products produced and/or sold.

We evaluate segment performance based on the non-GAAP financial measure of gross operating margin. Gross operating margin (either in total or by individual segment) is an important performance measure of the core profitability of our operations. This measure forms the basis of our internal financial reporting and is used by senior management in deciding how to allocate capital resources among business segments. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating segment results. The GAAP financial measure most directly comparable to total segment gross operating margin is operating income. Our non-GAAP financial measure of total segment gross operating margin should not be considered an alternative to GAAP operating income.

We define total segment gross operating margin as consolidated operating income before: (i) depreciation, amortization and accretion expense; (ii) operating lease expenses for which we do not have the payment obligation; (iii) gains and losses on the sale of assets; and (iv) general and administrative costs. Gross operating margin is exclusive of other income and expense transactions, provision for income taxes, minority interest, extraordinary charges and the cumulative effect of change in accounting principle. Gross operating margin by segment is calculated by subtracting segment operating costs and expenses (net of the adjustments noted above) from segment revenues, with both segment totals before the elimination of intersegment and intrasegment transactions.

Segment revenues include intersegment and intrasegment transactions, which are generally based on transactions made at market-related rates. Our consolidated revenues reflect the elimination of intercompany (both intersegment and intrasegment) transactions.

We include equity earnings from unconsolidated affiliates in our measurement of segment gross operating margin and operating income. Our equity investments with industry partners are a vital component of our business strategy. They are a means by which we conduct our operations to align our interests with those of our customers and/or suppliers. This method of operation enables us to achieve favorable economies of scale relative to the level of investment and business risk assumed versus what we could accomplish on a stand-alone basis. Many of these businesses perform supporting or complementary roles to our other business operations.

Our integrated midstream energy asset system (including the midstream energy assets of our equity method investees) provides services to producers and consumers of natural gas, NGLs, crude oil and certain petrochemicals. In general, hydrocarbons enter our asset system in a number of ways, such as an offshore natural gas or crude oil pipeline, an offshore platform, a natural gas processing plant, an onshore natural gas gathering pipeline, an NGL fractionator, an NGL storage facility, or an NGL transportation or distribution pipeline.

Many of our equity investees are included within our integrated midstream asset system. For example, we have ownership interests in several offshore natural gas and crude oil pipelines. Other examples include our use of the Promix NGL fractionator to process mixed NGLs extracted by our gas plants. The fractionated NGLs we receive from Promix can then be sold in our NGL marketing activities. Given the integral nature of our equity method investees to our operations, we believe the presentation of earnings from such investees as a component of gross operating margin and operating income is meaningful and appropriate.

Historically, substantially all of our consolidated revenues were earned in the United States and derived from a wide customer base. The majority of our plant-based operations are located in Texas, Louisiana, Mississippi, New Mexico and Wyoming. Our natural gas, NGL and crude oil pipelines are located in a number of regions of the United States including (i) the Gulf of Mexico offshore Texas and Louisiana; (ii) the south and southeastern United States (primarily in Texas, Louisiana, Mississippi and Alabama); and (iii) certain regions of the central and western United States, including the Rocky Mountains. Our marketing activities are headquartered in Houston, Texas and serve customers in a number of regions of the United States including the Gulf Coast, West Coast and Mid-Continent areas.

Consolidated property, plant and equipment and investments in and advances to unconsolidated affiliates are assigned to each segment on the basis of each asset's or investment's principal operations.

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The principal reconciling difference between consolidated property, plant and equipment and the total value of segment assets is construction-in-progress. Segment assets represent the net book carrying value of facilities and other assets that contribute to gross operating margin of that particular segment. Since assets under construction generally do not contribute to segment gross operating margin, such assets are excluded from segment asset totals until they are placed in service. Consolidated intangible assets and goodwill are assigned to each segment based on the classification of the assets to which they relate.

We consolidate the financial statements of Duncan Energy Partners with those of our own. As a result, our consolidated gross operating margin amounts include the gross operating margin amounts of Duncan Energy Partners on a 100% basis.

The following table shows our measurement of total segment gross operating margin for the periods indicated:

		For the Year Ended December 31,		
		2007	2006	2005
Revenues (1)		$ 16,950,125	$ 13,990,969	$ 12,256,959
Less:	Operating costs and expenses (1)	(16,009,051)	(13,089,091)	(11,546,225)
Add:	Equity in income of unconsolidated affiliates (1)	29,658	21,565	14,548
	Depreciation, amortization and accretion in operating costs and expenses (2)	513,840	440,256	413,441
	Operating lease expenses paid by EPCO (2)	2,105	2,109	2,112
	Loss (gain) on sale of assets in operating costs and expenses (2)	5,391	(3,359)	(4,488)
Total segment gross operating margin		$ 1,492,068	$ 1,362,449	$ 1,136,347

(1) These amounts are taken from our Statements of Consolidated Operations.

(2) These non-cash expenses are taken from the operating activities section of our Statements of Consolidated Cash Flows.

A reconciliation of our total segment gross operating margin to operating income and income before provision for income taxes, minority interest and the cumulative effect of changes in accounting principles follows:

	For the Year Ended December 31,		
	2007	2006	2005
Total segment gross operating margin	$1,492,068	$1,362,449	$1,136,347
Adjustments to reconcile total segment gross operating margin to operating income:			
Depreciation, amortization and accretion in operating costs and expenses	(513,840)	(440,256)	(413,441)
Operating lease expense paid by EPCO	(2,105)	(2,109)	(2,112)
Gain (loss) on sale of assets in operating costs and expenses	(5,391)	3,359	4,488
General and administrative costs	(87,695)	(63,391)	(62,266)
Consolidated operating income	883,037	860,052	663,016
Other expense, net	(303,463)	(229,967)	(225,178)
Income before provision for income taxes, minority interest and cumulative effect of change in accounting principle	$ 579,574	$ 630,085	$ 437,838

Information by segment, together with reconciliations to our consolidated totals, is presented in the following table:

	Reportable Segments					
	NGL Pipelines & Services	Onshore Natural Gas Pipelines & Services	Offshore Pipelines & Services	Petrochemical Services	Adjustments and Eliminations	Consolidated Totals
Revenues from third parties:						
Year ended December 31, 2007	$12,101,715	$1,788,219	$ 222,642	$2,184,833	$ —	$16,297,409
Year ended December 31, 2006	10,079,534	1,407,872	144,065	1,956,268	—	13,587,739
Year ended December 31, 2005	9,006,730	1,185,577	110,100	1,587,037	—	11,889,444
Revenues from related parties:						
Year ended December 31, 2007	369,654	281,876	1,169	17	—	652,716
Year ended December 31, 2006	110,409	291,023	1,798	—	—	403,230
Year ended December 31, 2005	16,689	350,025	696	105	—	367,515
Intersegment and intrasegment revenues:						
Year ended December 31, 2007	5,346,571	191,741	1,959	514,852	(6,055,123)	—
Year ended December 31, 2006	4,131,776	113,132	1,679	383,754	(4,630,341)	—
Year ended December 31, 2005	3,334,763	41,576	1,353	346,458	(3,724,150)	—
Total revenues:						
Year ended December 31, 2007	17,817,940	2,261,836	225,770	2,699,702	(6,055,123)	16,950,125
Year ended December 31, 2006	14,321,719	1,812,027	147,542	2,340,022	(4,630,341)	13,990,969
Year ended December 31, 2005	12,358,182	1,577,178	112,149	1,933,600	(3,724,150)	12,256,959
Equity in income of unconsolidated affiliates:						
Year ended December 31, 2007	6,031	9,540	12,628	1,459	—	29,658
Year ended December 31, 2006	5,715	2,872	11,909	1,069	—	21,565
Year ended December 31, 2005	5,553	2,384	6,125	486	—	14,548
Gross operating margin by individual business segment and in total:						
Year ended December 31, 2007	812,521	335,683	171,551	172,313	—	1,492,068
Year ended December 31, 2006	752,548	333,399	103,407	173,095	—	1,362,449
Year ended December 31, 2005	579,706	353,076	77,505	126,060	—	1,136,347
Segment assets:						
At December 31, 2007	4,570,555	3,702,297	1,452,568	687,856	1,173,988	11,587,264
At December 31, 2006	3,249,486	3,611,974	734,659	502,345	1,734,083	9,832,547
Investments in and advances to unconsolidated affiliates (see Note 11):						
At December 31, 2007	117,089	239,327	484,588	17,335	—	858,339
At December 31, 2006	111,229	124,591	310,136	18,603	—	564,559
Intangible Assets (see Note 13):						
At December 31, 2007	373,071	354,152	133,058	56,719	—	917,000
At December 31, 2006	417,950	386,149	152,376	47,480	—	1,003,955
Goodwill (see Note 13):						
At December 31, 2007	153,706	282,121	82,135	73,690	—	591,652
At December 31, 2006	152,595	282,121	82,135	73,690	—	590,541

In general, our historical operating results and/or financial position have been affected by business combinations and other acquisitions. The operating results of entities and assets we acquire are included in our financial results prospectively from their purchase dates.

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Note 17. Related Party Transactions

The following table summarizes our related party transactions for the periods indicated.

	For the Year Ended December 31,		
	2007	2006	2005
Revenues from consolidated operations			
EPCO and affiliates	$362,076	$ 98,671	$ 311
Unconsolidated affiliates	290,640	304,559	367,204
Total	$652,716	$403,230	$367,515
Operating costs and expenses			
EPCO and affiliates	$329,699	$311,537	$293,134
Unconsolidated affiliates	32,765	31,606	23,563
Total	$362,464	$343,143	$316,697
General and administrative expenses			
EPCO and affiliates	$ 56,518	$ 41,265	$ 40,954

We believe that the terms and provisions of our related party agreements are fair to us; however, such agreements and transactions may not be as favorable to us as we could have obtained from unaffiliated third parties.

Relationship with EPCO and affiliates

We have an extensive and ongoing relationship with EPCO and its affiliates, which include the following significant entities that are not a part of our consolidated group of companies:

- EPCO and its private company subsidiaries;
- EPGP, our sole general partner;
- Enterprise GP Holdings, which owns and controls our general partner;
- TEPPCO, which is owned and controlled by Enterprise GP Holdings;
- the Employee Partnerships (see Note 5); and
- Energy Transfer Equity, an equity method investment of Enterprise GP Holdings.

We also have an ongoing relationship with Duncan Energy Partners, the financial statements of which are consolidated with those of our own. Our transactions with Duncan Energy Partners are eliminated in consolidation. A description of our relationship with Duncan Energy Partners is presented within this Note 17.

EPCO is a private company controlled by Dan L. Duncan, who is also a Director and Chairman of EPGP, our general partner. At December 31, 2007, EPCO and its affiliates beneficially owned 147,986,045 (or 34.0%) of our outstanding common units, which includes 13,454,498 of our common units owned by Enterprise GP Holdings. In addition, at December 31, 2007, EPCO and its affiliates beneficially owned 77.1% of the limited partner interests of Enterprise GP Holdings and 100% of its general partner, EPE Holdings. Enterprise GP Holdings owns all of the membership interests of EPGP. The principal business activity of EPGP is to act as our managing partner. The executive officers and certain of the directors of EPGP and EPE Holdings are employees of EPCO.

As our general partner, EPGP received cash distributions of $124.4 million, $101.8 million and $76.8 million from us during the years ended December 31, 2007, 2006 and 2005, respectively. These amounts include incentive distributions of $107.4 million, $86.7 million and $63.9 million for the years ended December 31, 2007, 2006 and 2005, respectively.

We and EPGP are both separate legal entities apart from each other and apart from EPCO, Enterprise GP Holdings and their respective other affiliates, with assets and liabilities that are separate from those of EPCO, Enterprise GP Holdings and their respective other affiliates. EPCO and its private company subsidiaries and affiliates depend on the cash distributions they receive from us, Enterprise GP Holdings and other investments to fund their other operations and to meet their debt obligations. EPCO and its private company affiliates received $355.5 million, $306.5 million and $243.9 million in cash distributions from us and Enterprise GP Holdings during the years ended December 31, 2007, 2006 and 2005, respectively.

The ownership interests in us that are owned or controlled by Enterprise GP Holdings are pledged as security under its credit facility. In addition, substantially all of the ownership interests in us that are owned or controlled by EPCO and its affiliates, other than those interests owned by Enterprise GP Holdings, Dan Duncan LLC and certain trusts affiliated with Dan L. Duncan, are pledged as security under the credit facility of a private company affiliate of EPCO. This credit facility contains customary and other events of default relating to EPCO and certain affiliates, including Enterprise GP Holdings, TEPPCO and us.

We have entered into an agreement with EPCO to provide trucking services to us for the transportation of NGLs and other products. For the years ended December 31, 2007, 2006 and 2005, we paid this trucking affiliate $17.5 million, $20.7 million and $17.6 million, respectively, for such services.

We lease office space in various buildings from affiliates of EPCO. The rental rates in these lease agreements approximate market rates. For the years ended December 31, 2007, 2006 and 2005, we paid EPCO $5.6 million, $3.0 million and $2.7 million, respectively, for office space leases.

Historically, we entered into transactions with a Canadian affiliate of EPCO for the purchase and sale of NGL products in the normal course of business. These transactions were at market-related prices. We acquired this affiliate in October 2006 and began consolidating its financial statements with those of our own from the date of acquisition. For the year ended December 31, 2005 our revenues from this former affiliate were $0.3 million and our purchases were $61.0 million. For the nine months ended September 30, 2006, our revenues from this former affiliate were $55.8 million and our purchases were $43.4 million.

EPCO Administrative Services Agreement

We have no employees. All of our operating functions and general and administrative support services are provided by employees of EPCO pursuant to an administrative services agreement (the "ASA"). We, Duncan Energy Partners, Enterprise GP Holdings, TEPPCO and our respective general partners are parties to the ASA. The significant terms of the ASA are as follows:

- EPCO will provide selling, general and administrative services, and management and operating services, as may be necessary to manage and operate our businesses, properties and assets (all in accordance with prudent industry practices). EPCO will employ or otherwise retain the services of such personnel as may be necessary to provide such services.

- We are required to reimburse EPCO for its services in an amount equal to the sum of all costs and expenses incurred by EPCO which are directly or indirectly related to our business or activities (including expenses reasonably allocated to us by EPCO). In addition, we have agreed to pay all sales, use, excise, value added or similar taxes, if any, that may be applicable from time to time in respect of the services provided to us by EPCO.

- EPCO will allow us to participate as named insureds in its overall insurance program, with the associated premiums and other costs being allocated to us.

Under the ASA, EPCO subleases to us (for $1 per year) certain equipment which it holds pursuant to operating leases and has assigned to us its purchase option under such leases (the "retained leases").

EPCO remains liable for the actual cash lease payments associated with these agreements. We record the full value of these payments made by EPCO on our behalf as a non-cash related party operating lease expense, with the offset to partners' equity accounted for as a general contribution to our partnership. At December 31, 2007, the retained leases were for a cogeneration unit and approximately 100 railcars. Should we decide to exercise the purchase options associated with the retained leases, $2.3 million would be payable in 2008 and $3.1 million in 2016.

Our operating costs and expenses for the years ended December 31, 2007, 2006 and 2005 include reimbursement payments to EPCO for the costs it incurs to operate our facilities, including compensation of employees. We reimburse EPCO for actual direct and indirect expenses it incurs related to the operation of our assets. These reimbursements were $273.0 million, $285.4 million and $273.8 million during the years ended December 31, 2007, 2006 and 2005, respectively.

Likewise, our general and administrative costs for the years ended December 31, 2007, 2006 and 2005 include amounts we reimburse to EPCO for administrative services, including compensation of employees. In general, our reimbursement to EPCO for administrative services is either (i) on an actual basis for direct expenses it may incur on our behalf (e.g., the purchase of office supplies) or (ii) based on an allocation of such charges between the various parties to ASA based on the estimated use of such services by each party (e.g., the allocation of general legal or accounting salaries based on estimates of time spent on each entity's business and affairs). These reimbursements were $56.5 million, $41.3 million and $41.0 million during the years ended December 31, 2007, 2006 and 2005, respectively.

The ASA also addresses potential conflicts that may arise among Enterprise Products Partners (including EPGP), Enterprise GP Holdings (including EPE Holdings), Duncan Energy Partners (including DEP GP), and the EPCO Group. The EPCO Group includes EPCO and its other affiliates, but excludes Enterprise Products Partners, Enterprise GP Holdings, Duncan Energy Partners and their respective general partners. With respect to potential conflicts, the ASA provides, among other things, that:

- If a business opportunity to acquire "equity securities" (as defined below) is presented to the EPCO Group, Enterprise Products Partners (including EPGP), Enterprise GP Holdings (including EPE Holdings), Duncan Energy Partners (including DEP GP), then Enterprise GP Holdings will have the first right to pursue such opportunity. The term "equity securities" is defined to include:

  - general partner interests (or securities which have characteristics similar to general partner interests) or interests in "persons" that own or control such general partner or similar interests (collectively, "GP Interests") and securities convertible, exercisable, exchangeable or otherwise representing ownership or control of such GP Interests; and

  - incentive distribution rights and limited partner interests (or securities which have characteristics similar to incentive distribution rights or limited partner interests) in publicly traded partnerships or interests in "persons" that own or control such limited partner or similar interests (collectively, "non-GP Interests"); provided that such non-GP Interests are associated with GP Interests and are owned by the owners of GP Interests or their respective affiliates.

  Enterprise GP Holdings will be presumed to want to acquire the equity securities until such time as EPE Holdings advises the EPCO Group, EPGP and DEP GP that it has abandoned the pursuit of such business opportunity. In the event that the purchase price of the equity securities is reasonably likely to equal or exceed $100 million, the decision to decline the acquisition will be made by the Chief Executive Officer of EPE Holdings after consultation with and subject to the approval of the ACG Committee of EPE Holdings. If the purchase price is reasonably likely to be less than $100 million, the Chief Executive Officer of EPE Holdings may make the determination to decline the acquisition without consulting the ACG Committee of EPE Holdings.

  In the event that Enterprise GP Holdings abandons the acquisition and so notifies the EPCO Group, EPGP and DEP GP, Enterprise Products Partners will have the second right to pursue such acquisition. Enterprise Products Partners will be presumed to want to acquire the equity securities until such time as EPGP advises the EPCO Group and DEP GP that Enterprise Products Partners has abandoned the pursuit of such acquisition. In determining whether or not to pursue the acquisition, Enterprise Products Partners will follow the same procedures applicable to Enterprise GP Holdings, as described above but utilizing EPGP's Chief Executive Officer and ACG Committee.

In its sole discretion, Enterprise Products Partners may affirmatively direct such acquisition opportunity to Duncan Energy Partners. In the event this occurs, Duncan Energy Partners may pursue such acquisition.

In the event Enterprise Products Partners abandons the acquisition opportunity for the equity securities and so notifies the EPCO Group and DEP GP, the EPCO Group may pursue the acquisition or offer the opportunity to TEPPCO (including TEPPCO GP) and their controlled affiliates, in either case, without any further obligation to any other party or offer such opportunity to other affiliates.

- If any business opportunity not covered by the preceding bullet point (i.e. not involving "equity securities") is presented to the EPCO Group, Enterprise Products Partners (including EPGP), Enterprise GP Holdings (including EPE Holdings), or Duncan Energy Partners (including DEP GP), Enterprise Products Partners will have the first right to pursue such opportunity either for itself or, if desired by Enterprise Products Partners in its sole discretion, for the benefit of Duncan Energy Partners. It will be presumed that Enterprise Products Partners will pursue the business opportunity until such time as its general partner advises the EPCO Group, EPE Holdings and DEP GP that it has abandoned the pursuit of such business opportunity.

  In the event the purchase price or cost associated with the business opportunity is reasonably likely to equal or exceed $100 million, any decision to decline the business opportunity will be made by the Chief Executive Officer of EPGP after consultation with and subject to the approval of the ACG Committee of EPGP. If the purchase price or cost is reasonably likely to be less than $100 million, the Chief Executive Officer of EPGP may make the determination to decline the business opportunity without consulting EPGP's ACG Committee.

  In its sole discretion, Enterprise Products Partners may affirmatively direct such acquisition opportunity to Duncan Energy Partners. In the event this occurs, Duncan Energy Partners may pursue such acquisition.

  In the event that Enterprise Products Partners abandons the business opportunity for itself and Duncan Energy Partners and so notifies the EPCO Group, EPE Holdings and DEP GP, Enterprise GP Holdings will have the second right to pursue such business opportunity. It will be presumed that Enterprise GP Holdings will pursue such acquisition until such time as its general partner declines such opportunity (in accordance with the procedures described above for Enterprise Products Partners) and advises the EPCO Group that it has abandoned the pursuit of such business opportunity. Should this occur, the EPCO Group may either pursue the business opportunity or offer the business opportunity to TEPPCO (including TEPPCO GP) and their controlled affiliates without any further obligation to any other party or offer such opportunity to other affiliates.

None of Enterprise Products Partners, Enterprise GP Holdings, Duncan Energy Partners or their respective general partners or the EPCO Group have any obligation to present business opportunities to TEPPCO (including TEPPCO GP) or their controlled affiliates. Likewise, TEPPCO (including TEPPCO GP) and their controlled affiliates have no obligation to present business opportunities to Enterprise Products Partners, Enterprise GP Holdings, Duncan Energy Partners or their respective general partners or the EPCO Group.

Relationship with TEPPCO

TEPPCO became a related party to us in February 2005 in connection with the acquisition of TEPPCO GP by a private company subsidiary of EPCO. In May 2007, Enterprise GP Holdings purchased TEPPCO GP from this private company subsidiary of EPCO.

We received $67.6 million, $42.9 million and a nominal amount from TEPPCO during the years ended December 31, 2007, 2006 and 2005, respectively, from the sale of hydrocarbon products. We paid TEPPCO $19.4 million, $24.0 million and $17.2 million for NGL pipeline transportation and storage services during the years ended December 31, 2007, 2006 and 2005, respectively.

Purchase of Pioneer I plant from TEPPCO. In March 2006, we paid TEPPCO $38.2 million for its Pioneer I natural gas processing plant located in Opal, Wyoming and certain natural gas processing rights related to natural gas production from the Jonah and Pinedale fields located in the Greater Green River Basin in Wyoming. After an in-depth consideration of all relevant factors, this transaction was approved by the ACG Committee of our general partner and the Audit and Conflicts Committee of the general partner of TEPPCO. In addition, each party received a fairness opinion rendered by an independent advisor. TEPPCO will have no continued involvement in the contracts or in the operations of the Pioneer facility.

Jonah Joint Venture with TEPPCO. In August 2006, we became a joint venture partner with TEPPCO in its Jonah Gas Gathering Company ("Jonah"), which owns the Jonah Gas Gathering System located in the Greater Green River Basin of southwestern Wyoming. The Jonah Gathering System gathers and transports natural gas produced from the Jonah and Pinedale fields to regional natural gas processing plants and major interstate pipelines that deliver natural gas to end-user markets.

Prior to entering into the Jonah joint venture, we managed the construction of the Phase V expansion and funded the initial construction costs under a letter of intent we entered into in February 2006. In connection with the joint venture arrangement, we and TEPPCO plan to continue the Phase V expansion, which is expected to increase the capacity of the Jonah Gathering System from 1.5 Bcf/d to 2.4 Bcf/d and to significantly reduce system operating pressures, which we anticipate will lead to increased production rates and ultimate reserve recoveries. The first portion of the expansion, which has increased the system gathering capacity to 2.0 Bcf/d, was completed in July 2007 and the final phase of this expansion is expected to be completed by April 2008. The total anticipated cost of the Phase V expansion is expected to be approximately $505.0 million. We continue to manage the Phase V construction project.

Since August 1, 2006, we and TEPPCO have equally shared in the construction costs of the Phase V expansion. TEPPCO has reimbursed us $261.6 million, which represents 50% of total Phase V costs incurred through December 31, 2007. We had a receivable of $9.9 million from TEPPCO at December 31, 2007 for Phase V expansion costs.

TEPPCO was entitled to all distributions from the joint venture until specified milestones were achieved, at which point, we became entitled to receive 50% of the incremental cash flow from portions of the system placed in service as part of the expansion. Since the first phase of this expansion was reached in July 2007, we and TEPPCO have shared earnings based on a formula that takes into account our respective capital contributions, including expenditures by TEPPCO prior to the expansion.

At December 31, 2007, we owned an approximate 19.4% interest in Jonah and TEPPCO owns 80.6%. We operate the Jonah system. We account for our investment in the Jonah joint venture using the equity method.

The Jonah joint venture is governed by a management committee comprised of two representatives approved by us and two appointed by TEPPCO, each with equal voting power. After an in-depth consideration of all relevant factors, this transaction was approved by the ACG Committee of our general partner and the Audit and Conflicts Committee of the general partner of TEPPCO. The ACG Committee of our general partner received a fairness opinion in connection with this transaction. The transaction was reviewed and recommended for approval by the Audit and Conflicts Committee of TEPPCO GP with assistance from an independent financial advisor.

We have agreed to indemnify TEPPCO from any and all losses, claims, demands, suits, liabilities, costs and expenses arising out of or related to breaches of our representations, warranties, or covenants related to the Jonah joint venture. A claim for indemnification cannot be filed until the losses suffered by TEPPCO exceed $1.0 million. The maximum potential amount of future payments under the indemnity agreement is limited to $100.0 million. All indemnity payments are net of insurance recoveries that TEPPCO may receive from third-party insurance carriers. We carry insurance coverage that may offset any payments required under the indemnification.

Purchase of Houston-area pipelines from TEPPCO. In October 2006, we purchased certain idle pipeline assets in the Houston, Texas area from TEPPCO for $11.7 million in cash. The acquired pipelines became part of our Texas Intrastate System. The purchase of this asset was in accordance with the Board-approved management authorization policy.

Purchase and lease of pipelines for DEP South Texas NGL Pipeline System from TEPPCO. In January 2007, we purchased a 10-mile segment of pipeline from TEPPCO located in the Houston area for $8.0 million. This pipeline segment is part of the DEP South Texas NGL Pipeline System that commenced operations in January 2007. In addition, we entered into a lease with TEPPCO for an 11-mile interconnecting pipeline located in the Houston area that is part of the DEP South Texas NGL Pipeline System. Although the primary term of the lease expired in September 2007, it is being renewed on a month-to-month basis until construction of a parallel pipeline is completed in early 2008. These transactions were in accordance with the Board-approved management authorization policy.

Relationship with Energy Transfer Equity

Enterprise GP Holdings acquired equity method investments in Energy Transfer Equity and its general partner in May 2007. As a result, Energy Transfer Equity and its consolidated subsidiaries became related parties to our consolidated businesses.

For the eight months ended December 31, 2007, we recorded $294.4 million of revenues from Energy Transfer Partners, L.P. ("ETP"), primarily from NGL marketing activities. We incurred $35.2 million in operating costs and expenses for the eight months ended December 31, 2007. We have a long-term revenue generating contract with Titan Energy Partners, L.P. ("Titan"), a consolidated subsidiary of ETP. Titan purchases substantially all of its propane requirements from us. The contract continues until March 31, 2010 and contains renewal and extension options. We and Energy Transfer Company ("ETC OLP") transport natural gas on each other's systems and share operating expenses on certain pipelines. ETC OLP also sells natural gas to us.

Relationships with Unconsolidated Affiliates

Many of our unconsolidated affiliates perform supporting or complementary roles to our other business operations. See Note 16 of the Notes to Consolidated Financial Statements for a discussion of this alignment of commercial interests. Since we and our affiliates hold ownership interests in these entities and directly or indirectly benefit from our related party transactions with such entities, they are presented here.

The following information summarizes significant related party transactions with our current unconsolidated affiliates:

- We sell natural gas to Evangeline, which, in turn, uses the natural gas to satisfy supply commitments it has with a major Louisiana utility. Revenues from Evangeline were $268.0 million, $277.7 million and $331.5 million for the years ended December 31, 2007, 2006 and 2005. In addition, we furnished $1.1 million in letters of credit on behalf of Evangeline at December 31, 2007.

- We pay Promix for the transportation, storage and fractionation of NGLs. In addition, we sell natural gas to Promix for its plant fuel requirements. Expenses with Promix were $30.4 million, $34.9 million and $26.0 million for the years ended December 31, 2007, 2006 and 2005. Revenues from Promix were $17.3 million, $21.8 million and $25.8 million for the years ended December 31, 2007, 2006 and 2005.

- We perform management services for certain of our unconsolidated affiliates. We charged such affiliates $9.3 million, $8.9 million and $8.3 million for the years ended December 31, 2007, 2006 and 2005.

Relationship with Duncan Energy Partners

In September 2006, we formed a consolidated subsidiary, Duncan Energy Partners, to acquire, own and operate a diversified portfolio of midstream energy assets and to support the growth objectives of EPO. On February 5, 2007, this subsidiary completed its initial public offering of 14,950,000 common units at $21.00 per unit, which generated net proceeds to Duncan Energy Partners of $291.9 million. As consideration for assets contributed and reimbursement for capital expenditures related to these assets, Duncan Energy Partners distributed $260.6 million of these net proceeds to Enterprise Products Partners (along with $198.9 million in borrowings under its credit facility and a final amount of 5,351,571 common units of Duncan Energy Partners). Duncan Energy Partners used $38.5 million of net proceeds from the overallotment to redeem 1,950,000 of the 7,301,571 common units it had originally issued to Enterprise Products Partners, resulting in the final amount of 5,351,571 common units beneficially owned by Enterprise Products Partners. We used the cash received from Duncan Energy Partners to temporarily reduce amounts outstanding under EPO's Multi-Year Revolving Credit Facility.

In addition to the 34% direct ownership interest we retained in certain subsidiaries of Duncan Energy Partners, we also own the 2% general partner interest in Duncan Energy Partners and 26.4% of Duncan Energy Partners' outstanding common units. EPO directs the business operations of Duncan Energy Partners through its control of Duncan Holdings, LLC ("DEP GP"). Certain of our officers and directors are also beneficial owners of common units of Duncan Energy Partners (see Item 12).

For financial reporting purposes, we consolidate the financial statements of Duncan Energy Partners with those of our own and reflect its operations in our business segments. All intercompany transactions between us and Duncan Energy Partners are eliminated in the preparation of our consolidated financial statements. Also, due to common control of the entities by Dan L. Duncan, the initial consolidated balance sheet of Duncan Energy Partners reflects our historical carrying basis in each of the subsidiaries contributed to Duncan Energy Partners. Public ownership of Duncan Energy Partners' net assets and earnings are presented as a component of minority interest in our consolidated financial statements.

The borrowings of Duncan Energy Partners are presented as part of our consolidated debt; however, we do not have any obligation for the payment of interest or repayment of borrowings incurred by Duncan Energy Partners.

We have significant involvement with all of the subsidiaries of Duncan Energy Partners, including the following types of transactions: (i) we utilize storage services provided by Mont Belvieu Caverns to support our Mont Belvieu fractionation and other businesses; (ii) we buy natural gas from and sell natural gas to Acadian Gas in connection with our normal business activities; and (iii) we are the sole shipper on the DEP South Texas NGL Pipeline System.

We may contribute other equity interests in our subsidiaries to Duncan Energy Partners in the near term and use the proceeds we receive from Duncan Energy Partners to fund our capital spending program.

For additional information regarding Duncan Energy Partners, see "Other Items — Initial Public Offering of Duncan Energy Partners" under Item 7 of this annual report.

Omnibus Agreement. On February 5, 2007, EPO and Duncan Energy Partners entered into an Omnibus Agreement that governs our relationship with Duncan Energy Partners on the following matters:

- indemnification for certain environmental liabilities, tax liabilities and right-of-way defects;
- reimbursement of certain expenditures incurred by DEP South Texas NGL and Mont Belvieu Caverns;
- a right of first refusal to EPO in Duncan Energy Partners' current and future subsidiaries and a right of first refusal on the material assets of these entities, other than sales of inventory and other assets in the ordinary course of business; and
- a preemptive right with respect to equity securities issued by certain of Duncan Energy Partners' subsidiaries, other than as consideration in an acquisition or in connection with a loan or debt financing.

EPO has indemnified Duncan Energy Partners against certain pre-February 2007 environmental and related liabilities associated with the assets EPO contributed to Duncan Energy Partners at the time of its initial public offering. These liabilities include both known and unknown environmental and related liabilities. This indemnification obligation will terminate on February 5, 2010. There is an aggregate cap of $15.0 million on the amount of indemnity coverage. In addition, Duncan Energy Partners is not entitled to indemnification until the aggregate amount of claims it incurs exceeds $250 thousand. Liabilities resulting from a change of law after February 5, 2007 are excluded from the EPO environmental indemnity. In addition, EPO has indemnified Duncan Energy Partners for liabilities related to:

- certain defects in the easement rights or fee ownership interests in and to the lands on which any assets contributed to Duncan Energy Partners in connection with its initial public offering are located and failure to obtain certain consents and permits necessary to conduct its business that arise through February 5, 2010; and
- certain income tax liabilities attributable to the operation of the assets contributed to Duncan Energy Partners in connection with its initial public offering prior to February 5, 2007.

The Omnibus Agreement may not be amended without the prior approval of the ACG Committee if the proposed amendment will, in the reasonable discretion of DEP GP, adversely affect holders of the it's common units.

Neither we, nor EPO and any of its affiliates are restricted under the Omnibus Agreement from competing with Duncan Energy Partners. Except as otherwise expressly agreed in the EPCO administrative services agreement, EPO and any of its affiliates may acquire, construct or dispose of additional midstream energy or other assets in the future without any obligation to offer Duncan Energy Partners the opportunity to purchase or construct those assets. These agreements are in addition to other agreements relating to business opportunities and potential conflicts of interest set forth in the administrative services agreement with EPO, EPCO and other affiliates of EPCO.

In certain cases, EPO is responsible for funding 100% of project costs rather than sharing such costs with Duncan Energy Partners in accordance with the existing sharing ratio of 66% funded by Duncan Energy Partners and 34% funded by EPO. Under the Omnibus Agreement, EPO agreed to make additional contributions to Duncan Energy Partners as reimbursement for Duncan Energy Partners' 66% share of any excess project costs above (i) the $28.6 million of estimated project costs to complete the Phase II expansions of the DEP South Texas NGL Pipeline System and (ii) $14.1 million of estimated project costs for additional Mont Belvieu brine production capacity and above-ground storage reservoir projects. These projects were in progress at the time of Duncan Energy Partners' initial public offering. In December 2007, EPO made cash contributions totaling $9.9 million to Duncan Energy Partners' subsidiaries in connection with the Omnibus Agreement.

In December 2007, EPO made an additional $38.1 million cash contribution to Mont Belvieu Caverns for capital expenditures in which Duncan Energy Partners is not a participant. This contribution was in accordance with provisions of the Mont Belvieu Caverns' limited liability company agreement, which states that when Duncan Energy Partners elects to not participate in certain projects, then EPO is responsible for funding 100% of such projects. To the extent such non-participated projects generate incremental earnings for Mont Belvieu Caverns in the future, the sharing ratio for Mont Belvieu Caverns will be adjusted to allocate such incremental cash flows to EPO. Under the terms of the agreement, Duncan Energy Partners may elect to reacquire for consideration a 66% share of these projects at a later date.

Note 18. Provision for Income Taxes

Our provision for income taxes relates primarily to federal and state income taxes of Seminole and Dixie, our two largest corporations subject to such income taxes. In addition, with the amendment of the Texas Franchise Tax in 2006, we have become a taxable entity in the state of Texas. Our federal and state income tax provision is summarized below:

	For the Year Ended December 31,		
	2007	2006	2005
Current:			
Federal	$ 4,828	$ 7,694	$1,105
State	3,871	1,148	301
Total current	8,699	8,842	1,406
Deferred:			
Federal	2,784	6,109	5,968
State	3,774	6,372	988
Total deferred	6,558	12,481	6,956
Total provision for income taxes	$15,257	$21,323	$8,362

A reconciliation of the provision for income taxes with amounts determined by applying the statutory U.S. federal income tax rate to income before income taxes is as follows:

	For the Year Ended December 31,		
	2007	2006	2005
Pre Tax Net Book Income ("NBI")	$579,574	$630,085	$437,838
Revised Texas franchise tax	7,146	8,119	—
State income taxes (net of federal benefit)	325	(396)	838
Federal income taxes computed by applying the federal statutory rate to NBI of corporate entities	5,318	13,347	7,656
Taxes charged to cumulative effect of changes in accounting principle	—	(3)	65
Valuation allowance	2,347	123	—
Other permanent differences	121	133	(197)
Provision for income taxes	15,257	$ 21,323	$ 8,362
Effective income tax rate	2.6%	3.4%	1.9%

Significant components of deferred tax liabilities and deferred tax assets as of December 31, 2007 and 2006 are as follows:

	At December 31, 2007	At December 31, 2006
Deferred Tax Assets:		
Net operating loss carryovers	$ 23,270	$ 19,175
Credit carryover	26	26
Charitable contribution carryover	16	12
Employee benefit plans	3,214	1,990
Deferred revenue	642	328
Reserve for legal fees and damages	478	—
Equity investment in partnerships	409	223
Asset retirement obligation	80	43
Accruals	1,068	709
Total Deferred Tax Assets	29,203	22,506
Valuation allowance	(5,345)	(2,994)
Net Deferred Tax Assets	23,858	19,512
Deferred Tax Liabilities:		
Property, plant and equipment	40,520	30,604
Other	99	78
Total Deferred Tax Liabilities	40,619	30,682
Total Net Deferred Tax Liabilities	$ (16,761)	$ (11,170)
Current portion of total net deferred tax assets	$ 1,081	$ 698
Long-term portion of total net deferred tax liabilities	$ (17,842)	$ (11,868)

We had net operating loss carryovers of $23.3 million and $19.2 million at December 31, 2007 and 2006, respectively. These losses expire in various years between 2008 and 2028 and are subject to limitations on their utilization. We record a valuation allowance to reduce our deferred tax assets to the amount of future tax benefit that is more likely than not to be realized. The valuation allowance was $5.3 million and $3.0 million at December 31, 2007 and 2006, respectively, and serves to reduce the recognized tax benefit associated with carryovers of our corporate entities to an amount that will, more likely than not, be realized. The $2.3 million increase in valuation allowance for 2007 is comprised primarily of $1.6 million for Canadian Enterprise Gas Products, Ltd.

On May 18, 2006, the State of Texas enacted House Bill 3 which revised the pre-existing state franchise tax. In general, legal entities that conduct business in Texas are subject to the Revised Texas Franchise Tax, including previously non-taxable entities such as limited partnerships and limited liability partnerships. The tax is assessed on Texas sourced taxable margin which is defined as the lesser of (i) 70% of total revenue or (ii) total revenue less (a) cost of goods sold or (b) compensation and benefits.

Although the bill states that the Revised Texas Franchise Tax is not an income tax, it has the characteristics of an income tax since it is determined by applying a tax rate to a base that considers both revenues and expenses. Due to the enactment of the Revised Texas Franchise Tax, we recorded a net deferred tax liability of $3.8 million and $6.6 million during the years ended December 31, 2007 and 2006, respectively. The offsetting net charge of $3.8 million and $6.6 million is shown on our Statement of Consolidated Operations for the years ended December 31, 2007 and 2006, respectively, as a component of provision for income taxes.

Note 19. Earnings Per Unit

Basic earnings per unit is computed by dividing net income or loss allocated to limited partner interests by the weighted-average number of distribution-bearing units outstanding during a period. Diluted earnings per unit is computed by dividing net income or loss allocated to limited partner interests by the sum of (i) the weighted-average number of distribution-bearing units outstanding during a period (as used in determining basic earnings per unit); (ii) the weighted-average number of performance-based phantom units outstanding during a period; and (iii) the number of incremental common units resulting from the assumed exercise of dilutive unit options outstanding during a period (the "incremental option units").

In a period of net losses, restricted units, phantom units and incremental option units are excluded from the calculation of diluted earnings per unit due to their antidilutive effect. The dilutive incremental option units are calculated using the treasury stock method, which assumes that proceeds from the exercise of all in-the-money options at the end of each period are used to repurchase common units at an average market value during the period. The amount of common units remaining after the proceeds are exhausted represents the potentially dilutive effect of the securities.

The amount of net income or loss allocated to limited partner interests is net of our general partner's share of such earnings. The following table presents the allocation of net income to EPGP for the periods indicated:

	For The Year Ended December 31,		
	2007	2006	2005
Net income	$ 533,674	$601,155	$419,508
Less incentive earnings allocations to EPGP	(107,421)	(86,710)	(63,884)
Net income available after incentive earnings allocation	426,253	514,445	355,624
Multiplied by EPGP ownership interest	2.0%	2.0%	2.0%
Standard earnings allocation to EPGP	$ 8,525	$ 10,289	$ 7,112
Incentive earnings allocation to EPGP	$ 107,421	$ 86,710	$ 63,884
Standard earnings allocation to EPGP	8,525	10,289	7,112
EPGP interest in net income	$ 115,946	$ 96,999	$ 70,996

The following table presents our calculation of basic and diluted earnings per unit for the periods indicated:

	For The Year Ended December 31,		
	2007	2006	2005
Income before change in accounting principle and EPGP interest	$ 533,674	$ 599,683	$ 423,716
Cumulative effect of change in accounting principle	—	1,472	(4,208)
Net income	533,674	601,155	419,508
EPGP interest in net income	(115,946)	(96,999)	(70,996)
Net income available to limited partners	$ 417,728	$ 504,156	$ 348,512
BASIC EARNINGS PER UNIT			
Numerator			
Income before change in accounting principle and EPGP interest	$ 533,674	$ 599,683	$ 423,716
Cumulative effect of change in accounting principle	—	1,472	(4,208)
EPGP interest in net income	(115,946)	(96,999)	(70,996)
Limited partners' interest in net income	$ 417,728	$ 504,156	$ 348,512
Denominator			
Common units	432,513	413,472	413,472
Time-vested restricted units	1,446	970	970
Total	433,959	414,442	414,442
Basic earnings per unit			
Income per unit before change in accounting principle and EPGP interest	$ 1.23	$ 1.45	$ 1.11
Cumulative effect of change in accounting principle	—	—	(0.01)
EPGP interest in net income	(0.27)	(0.23)	(0.19)
Limited partners' interest in net income	$ 0.96	$ 1.22	$ 0.91
DILUTED EARNINGS PER UNIT			
Numerator			
Income before change in accounting principle and EPGP interest	$ 533,674	$ 599,683	$ 423,716
Cumulative effect of change in accounting principle	—	1,472	(4,208)
EPGP interest in net income	(115,946)	(96,999)	(70,996)
Limited partners' interest in net income	$ 417,728	$ 504,156	$ 348,512
Denominator			
Common units	432,513	413,472	381,857
Time-vested restricted units	1,446	970	606
Performance-based restricted units	9	20	45
Incremental option units	459	297	455
Total	434,427	414,759	382,963
Diluted earnings per unit			
Income per unit before change in accounting principle and EPGP interest	$ 1.23	$ 1.45	$ 1.11
Cumulative effect of change in accounting principle	—	—	(0.01)
EPGP interest in net income	(0.27)	(0.23)	(0.19)
Limited partners' interest in net income	$ 0.96	$ 1.22	$ 0.91

Note 20. Commitments and Contingencies

Litigation

On occasion, we or our unconsolidated affiliates are named as defendants in litigation relating to our normal business activities, including regulatory and environmental matters. Although we are insured against various business risks to the extent we believe it is prudent, there is no assurance that the nature and amount of such insurance will be adequate, in every case, to indemnify us against liabilities arising from future legal proceedings as a result of our ordinary business activities. We are unaware of any significant litigation, pending or threatened, that could have a significant adverse effect on our financial position, cash flows or results of operations.

On September 18, 2006, Peter Brinckerhoff, a purported unitholder of TEPPCO, filed a complaint in the Court of Chancery of New Castle County in the State of Delaware, in his individual capacity, as a putative class action on behalf of other unitholders of TEPPCO, and derivatively on behalf of TEPPCO, concerning, among other things, certain transactions involving TEPPCO and us or our affiliates. Mr. Brinkerhoff filed an amended complaint on July 12, 2007. The amended complaint names as defendants (i) TEPPCO, its current and certain former directors, and certain of its affiliates; (ii) us and certain of our affiliates; (iii) EPCO, Inc.; and (iv) Dan L. Duncan.

The amended complaint alleges, among other things, that the defendants have caused TEPPCO to enter into certain transactions with us or our affiliates that were unfair to TEPPCO or otherwise unfairly favored us or our affiliates over TEPPCO. These transactions are alleged to include the joint venture to further expand the Jonah Gathering System entered into by TEPPCO and one of our affiliates in August 2006 and the sale by TEPPCO to one of our affiliates of the Pioneer gas processing plant in March 2006. The amended complaint seeks (i) rescission of these transactions or an award of rescissory damages with respect thereto; (ii) damages for profits and special benefits allegedly obtained by defendants as a result of the alleged wrongdoings in the amended complaint; and (iii) awarding plaintiff costs of the action, including fees and expenses of his attorneys and experts. We believe this lawsuit is without merit and intend to vigorously defend against it. See Note 17 for additional information regarding our relationship with TEPPCO.

On February 13, 2007, EPO received notice from the U.S. Department of Justice ("DOJ") that it was the subject of a criminal investigation related to an ammonia release in Kingman County, Kansas on October 27, 2004 from a pressurized anhydrous ammonia pipeline owned by a third party, Magellan Ammonia Pipeline, L.P. ("Magellan"). EPO is the operator of this pipeline. On February 14, 2007, EPO received a letter from the Environment and Natural Resources Division ("ENRD") of the DOJ regarding this incident and a previous release of ammonia on September 27, 2004 from the same pipeline. The ENRD has indicated that it may pursue civil damages against EPO and Magellan as a result of these incidents. Based on this correspondence from the ENRD, the statutory maximum amount of civil fines that could be assessed against EPO and Magellan is up to $17.4 million in the aggregate. EPO is cooperating with the DOJ and is hopeful that an expeditious resolution of this civil matter acceptable to all parties will be reached in the near future. Magellan has agreed to indemnify EPO for the civil matter. On September 4, 2007, we and the DOJ entered into a plea agreement whereby a wholly-owned subsidiary of EPO, Mapletree, LLC, pleaded guilty to a misdemeanor charge of negligence in connection with the releases and paid a fine of $1.0 million. The plea agreement concludes the DOJ’s criminal investigation into the ammonia releases. At this time, we do not believe that a final resolution of the civil claims by the ENRD will have a material impact on our consolidated financial position, cash flows or results of operations.

On October 25, 2006, a rupture in the Magellan Ammonia Pipeline resulted in the release of ammonia near Clay Center, Kansas. The pipeline has been repaired and environmental remediation tasks related to this incident have been completed. At this time, we do not believe that this incident will have a material impact on our consolidated financial position, cash flows or results of operations.

Several lawsuits have been filed by municipalities and other water suppliers against a number of manufacturers of reformulated gasoline containing methyl tertiary butyl ether. In general, such suits have not named manufacturers of this product as defendants, and there have been no such lawsuits filed against our subsidiary that owns an octane-additive production facility. It is possible, however, that former manufacturers such as our subsidiary could ultimately be added as defendants in such lawsuits or in new lawsuits.

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Contractual Obligations

The following table summarizes our various contractual obligations at December 31, 2007. A description of each type of contractual obligation follows:

	Payment or Settlement due by Period						
Contractual Obligations	**Total**	**2008**	**2009**	**2010**	**2011**	**2012**	**Thereafter**
Scheduled maturities of long-term debt	$6,896,500	$ —	$500,000	$591,840	$650,000	$697,160	$4,457,500
Operating lease obligations	$ 325,705	$ 27,785	$ 25,866	$ 23,306	$ 23,785	$ 23,137	$ 201,826
Purchase obligations:							
Product purchase commitments:							
Estimated payment obligations:							
Natural gas	$ 685,600	$ 137,345	$136,970	$136,970	$136,970	$137,345	$ —
NGLs	$4,041,275	$ 697,277	$415,132	$415,132	$415,132	$415,132	$1,683,470
Petrochemicals	$4,065,675	$1,751,152	$746,916	$514,155	$233,745	$141,623	$ 678,084
Other	$ 60,385	$ 31,392	$ 14,962	$ 2,152	$ 2,051	$ 1,780	$ 8,048
Underlying major volume commitments:							
Natural gas (in BBtus)	91,350	18,300	18,250	18,250	18,250	18,300	—
NGLs (in MBbls)	50,798	9,745	5,086	5,086	5,086	5,086	20,709
Petrochemicals (in MBbls)	45,207	20,115	8,100	5,604	2,541	1,556	7,291
Service payment commitments	$ 8,962	$ 6,745	$ 1,564	$ 93	$ 93	$ 93	$ 374
Capital expenditure commitments	$ 569,654	$ 569,654	$ —	$ —	$ —	$ —	$ —

*Scheduled Maturities of Long-Term Debt***.** We have long-term and short-term payment obligations under debt agreements such as the indentures governing EPO's senior notes and the credit agreement governing EPO's Multi-Year Revolving Credit Facility. Amounts shown in the preceding table represent our scheduled future maturities of debt principal for the periods indicated. See Note 14 for additional information regarding our consolidated debt obligations.

Operating Lease Obligations. We lease certain property, plant and equipment under noncancelable and cancelable operating leases. Amounts shown in the preceding table represent minimum cash lease payment obligations under our operating leases with terms in excess of one year.

Our significant lease agreements involve (i) the lease of underground caverns for the storage of natural gas and NGLs, (ii) leased office space with an affiliate of EPCO, (iii) a railcar unloading terminal in Mont Belvieu, Texas and (iv) land held pursuant to right-of-way agreements. In general, our material lease agreements have original terms that range from 2 to 28 years and include renewal options that could extend the agreements for up to an additional 20 years.

Lease expense is charged to operating costs and expenses on a straight line basis over the period of expected economic benefit. Contingent rental payments are expensed as incurred. We are generally required to perform routine maintenance on the underlying leased assets. In addition, certain leases give us the option to make leasehold improvements. Maintenance and repairs of leased assets resulting from our operations are charged to expense as incurred. We did not make any significant leasehold improvements during the years ended December 31, 2007, 2006 or 2005; however, we did incur $9.3 million of repair costs associated with our lease of an underground natural gas storage facility in 2006.

The operating lease commitments shown in the preceding table exclude the non-cash, related party expense associated with equipment leases contributed to us by EPCO at our formation (the "retained leases"). EPCO remains liable for the actual cash lease payments associated with these agreements, which it accounts for as operating leases. At December 31, 2007, the retained leases were for a cogeneration unit and approximately 100 railcars. EPCO's minimum future rental payments under these leases are $2.1 million for 2008, $0.7 million for each of the years 2009 through 2015 and $0.3 million for 2016. We record the full value of these payments made by EPCO on our behalf as a non-cash related party operating lease expense, with the offset to partners' equity accounted for as a general contribution to our partnership.

The retained lease agreements contain lessee purchase options, which are at prices that approximate fair value of the underlying leased assets. EPCO has assigned these purchase options to us.

Should we decide to exercise the remaining purchase options, up to an additional $2.3 million would be payable in 2008 and $3.1 million in 2016.

Lease and rental expense included in operating costs and expenses was $38.5 million, $39.3 million and $34.9 million during the years ended December 31, 2007, 2006 and 2005, respectively.

*Purchase Obligations***.** We define a purchase obligation as an agreement to purchase goods or services that is enforceable and legally binding (unconditional) on us that specifies all significant terms, including: fixed or minimum quantities to be purchased; fixed, minimum or variable price provisions; and the approximate timing of the transactions. We have classified our unconditional purchase obligations into the following categories:

- We have long and short-term product purchase obligations for NGLs, certain petrochemicals and natural gas with third-party suppliers. The prices that we are obligated to pay under these contracts approximate market prices at the time we take delivery of the volumes. The preceding table shows our volume commitments and estimated payment obligations under these contracts for the periods indicated. Our estimated future payment obligations are based on the contractual price under each contract for purchases made at December 31, 2007 applied to all future volume commitments. Actual future payment obligations may vary depending on market prices at the time of delivery. At December 31, 2007, we do not have any product purchase commitments with fixed or minimum pricing provisions with remaining terms in excess of one year.

- We have long and short-term commitments to pay third-party providers for services such as equipment maintenance agreements. Our contractual payment obligations vary by contract. The preceding table shows our future payment obligations under these service contracts.

- We have short-term payment obligations relating to our capital projects and those of our unconsolidated affiliates. These commitments represent unconditional payment obligations to vendors for services rendered or products purchased. The preceding table presents our share of such commitments for the periods indicated.

Commitments under equity compensation plans of EPCO

In accordance with our agreements with EPCO, we reimburse EPCO for our share of its compensation expense associated with certain employees who perform management, administrative and operating functions for us (see Note 17). This includes costs associated with unit option awards granted to these employees to purchase our common units. At December 31, 2007, there were 2,315,000 unit options outstanding for which we were responsible for reimbursing EPCO for the costs of such awards.

The weighted-average strike price of unit option awards outstanding at December 31, 2007 was $26.18 per common unit. At December 31, 2007, 335,000 of these unit options were exercisable. An additional 285,000, 380,000, 510,000 and 805,000 of these unit options will be exercisable in 2008, 2009, 2010 and 2011, respectively. As these options are exercised, we will reimburse EPCO in the form of a special cash distribution for the difference between the strike price paid by the employee and the actual purchase price paid for the units awarded to the employee. See Note 5 for additional information regarding our accounting for equity awards.

Performance Guaranty

In December 2004, a subsidiary of ours entered into the Independence Hub Agreement (the "Agreement") with six oil and natural gas producers. The Agreement, as amended, obligated our subsidiary to construct the Independence Hub offshore platform and to process 1 Bcf/d of natural gas and condensate for the producers. We guaranteed to the producers the construction-related performance of our subsidiary up to an amount of $340.8 million. The performance guaranty expired during the second quarter of 2007. However at December 31, 2006, as a component of other current liabilities on our Consolidated Balance Sheet, we recorded the fair value of the performance guaranty at an estimated $1.2 million using an expected present value approach. This was in accordance with FIN 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others,"

Other Claims

As part of our normal business activities with joint venture partners and certain customers and suppliers, we occasionally have claims made against us as a result of disputes related to contractual agreements or similar arrangements. As of December 31, 2007, claims against us totaled approximately $37.9 million. These matters are in various stages of assessment and the ultimate outcome of such disputes cannot be reasonably estimated. However, in our opinion, the likelihood of a material adverse outcome related to disputes against us is remote. Accordingly, accruals for loss contingencies related to these matters, if any, that might result from the resolution of such disputes have not been reflected in our consolidated financial statements.

Other Commitments

We transport and store natural gas, NGLs and petrochemicals for third parties under various processing, storage, transportation and similar agreements. These volumes are (i) accrued as product payables on our Consolidated Balance Sheets, (i) in transit for delivery to our customers or (iii) held at our storage facilities for redelivery to our customers. We are insured against any physical loss of such volumes due to catastrophic events. Under the terms of our natural gas, NGL and petrochemical storage agreements, we are generally required to redeliver volumes to the owner on demand. At December 31, 2007, NGL and petrochemical products aggregating 25.2 million barrels were due to be redelivered to their owners along with 16,223 BBtus of natural gas. See Note 2 for more information regarding accrued product payables.

Note 21. Significant Risks and Uncertainties

Nature of Operations in Midstream Energy Industry

Our operations are within the midstream energy industry, which includes gathering, transporting, processing, fractionating and storing natural gas, NGLs, certain petrochemicals and crude oil. As such, our results of operations, cash flows and financial condition may be affected by changes in the commodity prices of these hydrocarbon products, including changes in the relative price levels among these products. In general, the prices of natural gas, NGLs, crude oil and other hydrocarbon products are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control.

Our profitability could be impacted by a decline in the volume of hydrocarbon products transported, gathered or processed at our facilities. A material decrease in natural gas or crude oil production or crude oil refining for reasons such as depressed commodity prices or a decrease in exploration and development activities, could result in a decline in the volume of natural gas, NGLs and crude oil handled by our facilities.

A reduction in demand for NGL products by the petrochemical, refining or heating industries, whether because of (i) general economic conditions, (ii) reduced demand by consumers for the end products made using NGLs, (iii) increased competition from petroleum-based products due to pricing differences, (iv) adverse weather conditions, (v) government regulations affecting energy commodity prices, production levels of hydrocarbons or the content of motor gasoline or (vi) other reasons, could adversely affect our results of operations, cash flows and financial position.

Credit Risk due to Industry Concentrations

A substantial portion of our revenues are derived from companies in the domestic natural gas, NGL and petrochemical industries. This concentration could affect our overall exposure to credit risk since these customers may be affected by similar economic or other conditions. We generally do not require collateral for our accounts receivable; however, we do attempt to negotiate offset, prepayment, or automatic debit agreements with customers that are deemed to be credit risks in order to minimize our potential exposure to any defaults.

Our revenues are derived from a wide customer base. During 2007, 2006 and 2005, our largest customer was The Dow Chemical Company and its affiliates, which accounted for 6.9%, 6.1% and 6.8%, respectively, of our consolidated revenues.

Counterparty Risk with respect to Financial Instruments

Where we are exposed to credit risk in our financial instrument transactions, we analyze the counterparty's financial condition prior to entering into an agreement, establish credit and/or margin limits and monitor the appropriateness of these limits on an ongoing basis. We generally do not require collateral for our financial instrument transactions.

Weather-Related Risks

We participate as named insureds in EPCO's current insurance program, which provides us with property damage, business interruption and other coverages, which are customary for the nature and scope of our operations. EPCO attempts to place all insurance coverage with carriers having ratings of "A" or higher. However, two carriers associated with the EPCO insurance program were downgraded by Standard & Poor's during 2006. One of these carriers is currently at "A-" and the other, "BBB." At present, there is no indication that these two carriers would be unable to fulfill any insuring obligation. Furthermore, we currently do not have any claims which might be affected by these carriers. EPCO continues to monitor these situations.

We believe EPCO maintains adequate insurance coverage on our behalf; however, insurance will not cover every type of interruption that might occur. As a result of severe hurricanes such as Katrina and Rita that occurred in 2005, market conditions for obtaining property damage insurance coverage were difficult during 2006. Under EPCO's renewed insurance programs, coverage was more restrictive, including increased physical damage and business interruption deductibles. For example, our deductible for onshore physical damage increased from $2.5 million to $5.0 million per event and our deductible period for onshore business interruption claims increased from 30 days to 60 days. Additional restrictions will be applied in connection with damage caused by named windstorms.

In addition to changes in coverage, the cost of property damage insurance increased substantially between 2006 and prior periods. At present, our annualized cost of insurance premiums for all lines of coverage is approximately $52.4 million. During the year ended December 31, 2006, our annualized cost of insurance premiums for all lines of coverage was approximately $49.2 million, which represented a $28.1 million, or 133%, increase from our 2005 annualized insurance cost.

If we were to incur a significant liability for which we were not fully insured, it could have a material impact on our consolidated financial position and results of operations. In addition, the proceeds of any such insurance may not be paid in a timely manner and may be insufficient to reimburse us for repair costs or lost income. Any event that interrupts the revenues generated by our consolidated operations, or which causes us to make significant expenditures not covered by insurance, could reduce our ability to pay distributions to partners and, accordingly, adversely affect the market price of our common units.

The following is a discussion of the general status of our insurance claims related to recent significant storm events. To the extent we include any estimate or range of estimates regarding the dollar value of damages, please be aware that a change in our estimates may occur as additional information becomes available.

Hurricane Ivan insurance claims. During the years ended December 31, 2007 and 2006, we received cash reimbursements from insurance carriers totaling $1.3 million and $24.1 million, respectively,

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related to property damage claims. If the final recovery of funds is different than the amount previously expended, we will recognize an income impact at that time.

We have submitted business interruption insurance claims for our estimated losses caused by Hurricane Ivan, which struck the eastern U.S. Gulf Coast region in September 2004. During the years ended December 31, 2007 and 2006, we received $0.4 million and $17.4 million of nonrefundable cash proceeds from such claims. We are continuing our efforts to collect residual balances and expect to complete the process during 2008. To the extent we receive nonrefundable cash proceeds from business interruption insurance claims, they are recorded as a gain in our Statements of Consolidated Operations in the period of receipt.

Hurricanes Katrina and Rita insurance claims. Hurricanes Katrina and Rita, both significant storms, affected certain of our Gulf Coast assets in August and September of 2005, respectively. With respect to these storms, we have $37.6 million of estimated property damage claims outstanding at December 31, 2007, that we believe are probable of collection during the period 2008 through 2009. We continue to pursue collection of our property damage claims related to these named storms. As of December 31, 2007, we had received practically all proceeds from our business interruption claims related to these storm events.

The following table summarizes proceeds we received during the periods indicated from business interruption and property damage insurance claims with respect to certain named storms:

	For the Year Ended December 31,	
	2007	**2006**
Business interruption proceeds:		
Hurricane Ivan	$ 377	$17,382
Hurricane Katrina	19,005	24,500
Hurricane Rita	14,955	22,000
Other	996	—
Total proceeds	35,333	63,882
Property damage proceeds:		
Hurricane Ivan	1,273	24,104
Hurricane Katrina	79,651	7,500
Hurricane Rita	24,105	3,000
Other	184	—
Total proceeds	105,213	34,604
Total	$140,546	$98,486

During 2007, we collected $0.8 million of business interruption proceeds that were not related to storm events. As well, during 2005, we received $4.8 million of nonrefundable cash proceeds from business interruption claims.

Note 22. Supplemental Cash Flow Information

The following table provides information regarding (i) the net effect of changes in our operating assets and liabilities; (ii) cash payments for interest and (iii) cash payments for federal and state income taxes for the periods indicated.

	For the Year Ended December 31,		
	2007	2006	2005
Decrease (increase) in:			
Accounts and notes receivable	$(703,346)	$155,628	$(363,857)
Inventories	(14,051)	(66,288)	(148,846)
Prepaid and other current assets	41,266	14,261	(51,163)
Other assets	5,630	(22,581)	58,762
Increase (decrease) in:			
Accounts payable	53,981	(12,278)	45,802
Accrued product payables	862,941	(8,344)	349,979
Accrued expenses	120,054	(62,963)	(161,989)
Accrued interest	40,107	19,671	858
Other current liabilities	37,248	74,206	2,274
Other liabilities	(2,524)	(7,894)	1,785
Net effect of changes in operating accounts	$ 441,306	$ 83,418	$(266,395)
Cash payments for interest, net of $75,476, $55,660 and $22,046 capitalized in 2007, 2006 and 2005, respectively	$ 325,339	$213,365	$ 239,088
Cash payments for federal and state income taxes	$ 5,760	$ 10,497	$ 5,160

The following table provides supplemental cash flow information regarding business combinations we completed during the periods indicated. See Note 12, for additional information regarding our business combination transactions.

	For the Year Ended December 31,		
	2007	2006	2005
Assets acquired	$37,037	$ 477,015	$353,176
Less liabilities assumed	(1,244)	(19,403)	(23,940)
Net assets acquired	35,793	457,612	329,236
Less equity issued	—	(181,112)	—
Less cash acquired	—	—	(2,634)
Cash used for business combinations, net of cash received	$35,793	$ 276,500	$326,602

We incurred liabilities for construction in progress that had not been paid at December 31, 2007, 2006 and 2005 of $95.5 million, $195.1 million and $130.2 million, respectively. Such amounts are not included under the caption "Capital expenditures" on the Statements of Consolidated Cash Flows.

Third parties may be obligated to reimburse us for all or a portion of expenditures on certain of our capital projects. The majority of such arrangements are associated with projects related to pipeline construction and production well tie-ins. We received $57.5 million, $60.5 million and $47.0 million as contributions in aid of our construction costs during the years ended December 31, 2007, 2006 and 2005, respectively.

In June 2005, we received $47.5 million in cash from Cameron Highway as a return of investment. These funds were distributed to us in connection with the refinancing of Cameron Highway’s project debt.

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Note 23. Quarterly Financial Information (Unaudited)

The following table presents selected quarterly financial data for the years ended December 31, 2007 and 2006:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
For the Year Ended December 31, 2007:				
Revenues	$3,322,854	$4,212,806	$4,111,996	$5,302,469
Operating income	187,924	214,562	210,830	269,721
Income before change in accounting principle	112,045	142,154	117,606	161,869
Net income	112,045	142,154	117,606	161,869
Income per unit before change in accounting principle:				
Basic	$ 0.20	$ 0.26	$ 0.20	$ 0.30
Diluted	$ 0.20	$ 0.26	$ 0.20	$ 0.30
Net income per unit:				
Basic	$ 0.20	$ 0.26	$ 0.20	$ 0.30
Diluted	$ 0.20	$ 0.26	$ 0.20	$ 0.30
For the Year Ended December 31, 2006:				
Revenues	$3,250,074	$3,517,853	$3,872,525	$3,350,517
Operating income	193,500	186,045	274,184	206,323
Income before change in accounting principle	132,302	126,295	208,302	132,784
Net income	133,777	126,295	208,302	132,781
Income per unit before change in accounting principle:				
Basic	$ 0.28	$ 0.26	$ 0.43	$ 0.25
Diluted	$ 0.28	$ 0.26	$ 0.43	$ 0.25
Net income per unit:				
Basic	$ 0.28	$ 0.26	$ 0.43	$ 0.25
Diluted	$ 0.28	$ 0.26	$ 0.43	$ 0.25

Note 24. Condensed Financial Information of EPO

EPO conducts substantially all of our business. Currently, we have no independent operations and no material assets outside those of EPO. EPO consolidates the financial statements of Duncan Energy Partners with those of its own.

We guarantee the debt obligations of EPO, with the exception of the Dixie revolving credit facility, Duncan Energy Partners' credit facility and the senior subordinated notes assumed in connection with the GulfTerra Merger. If EPO were to default on any debt we guarantee, we would be responsible for full repayment of that obligation. See Note 14 for additional information regarding our consolidated debt obligations.

The reconciling items between our consolidated financial statements and those of EPO are insignificant. The following table presents condensed consolidated balance sheet data for EPO at the dates indicated:

	At December 31,	
	2007	2006
ASSETS		
Current assets	$ 2,544,973	$ 1,915,937
Property, plant and equipment, net	11,587,264	9,832,547
Investments in and advances to unconsolidated affiliates, net	858,339	564,559
Intangible assets, net	917,000	1,003,955
Goodwill	591,652	590,541
Deferred tax asset	3,113	1,632
Other assets	112,345	74,103
Total	$16,614,686	$13,983,274
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities	$ 3,044,002	$ 1,986,444
Long-term debt	6,906,145	5,295,590
Other long-term liabilities	95,112	99,845
Minority interest	439,854	136,249
Partners' equity	6,129,573	6,465,146
Total	$16,614,686	$13,983,274
Total EPO debt obligations guaranteed by us	$ 6,686,500	$ 5,314,000

The following table presents condensed consolidated statements of operations data for EPO for the periods indicated:

	For the Year Ended December 31,		
	2007	2006	2005
Revenues	$16,950,125	$13,990,969	$12,256,959
Costs and expenses	16,094,248	13,148,530	11,605,923
Equity in income of unconsolidated affiliates	29,658	21,565	14,548
Operating income	885,535	864,004	665,584
Other expense	(305,236)	(231,876)	(226,075)
Income before provision for income taxes, minority interest and change in accounting principle	580,299	632,128	439,509
Provision for income taxes	(15,317)	(21,198)	(8,362)
Income before minority interest and change in accounting principle	564,982	610,930	431,147
Minority interest	(30,737)	(9,190)	(5,989)
Income before change in accounting principle	534,245	601,740	425,158
Cumulative effect of change in accounting principle	—	1,472	(4,208)
Net income	$ 534,245	$ 603,212	$ 420,950

Note 25. Subsequent Event

Enterprise Products 2008 Long-Term Incentive Plan

On January 29, 2008, the unitholders of Enterprise Products Partners approved the Enterprise Products 2008 Long-Term Incentive Plan (the "Incentive Plan"), which provides for awards of the Partnership's common units and other rights to the Partnership's non-employee directors and to consultants and employees of EPCO and its affiliates providing services to the Partnership. Awards under the Incentive Plan may be granted in the form of restricted units, phantom units, unit options, unit appreciation rights and distribution equivalent rights. The Incentive Plan will be administered by EPGP's ACG Committee. Up to 10,000,000 of the Partnership's common units may be granted as awards under the Incentive Plan, with such amount subject to adjustment as provided for under the terms of the plan.

The exercise price of unit options or UARs awarded to participants will be determined by the ACG Committee (at its discretion) at the date of grant and may be no less than the fair market value of the option award as of the date of grant. The Incentive Plan may be amended or terminated at any time by the Board of Directors of EPCO or EPGP's ACG Committee; however, any material amendment, such as a significant increase in the number of units available under the plan or a change in the types of awards available under the plan, would require the approval of the unitholders of the Partnership. The ACG Committee is also authorized to make adjustments in the terms and conditions of, and the criteria included in awards under the plan in specified circumstances. The Incentive Plan is effective until January 29, 2018 or, if earlier, the time which all available units under the Incentive Plan have been delivered to participants or the time of termination of the plan by EPCO or EPGP's ACG Committee.

Enterprise Unit L.P. Long-Term Incentive Plan

On February 20, 2008, EPCO formed Enterprise Unit L.P. ("Enterprise LP") to serve as an incentive arrangement for certain employees of EPCO through a "profits interest" in Enterprise LP. On that date, EPCO Holdings, Inc. ("EPCO Holdings") agreed to contribute $18,000,000 in the aggregate (the "Initial Contribution") to Enterprise LP and was admitted as the Class A limited partner. Certain key employees of EPCO including our Chief Executive Officer and Chief Financial Officer were issued Class B limited partner interests and admitted as Class B limited partners of Enterprise LP without any capital contribution. As with the awards granted in connection with the other Employee Partnerships, these awards are designed to provide additional long-term incentive compensation for such employees. The profits interest awards (or Class B limited partner interests) in Enterprise LP entitle the holder to participate in the appreciation in value of Enterprise GP Holdings units and our common units and are subject to forfeiture.

A portion of the fair value of these equity awards will be allocated to us under the EPCO administrative services agreement as a non-cash expense. We will not reimburse EPCO, Enterprise LP or any of their affiliates or partners, through the administrative services agreement or otherwise, for any expenses related to Enterprise LP, including the Initial Contribution by EPCO Holdings.

The Class B limited partner interests in Enterprise LP that are owned by EPCO employees are subject to forfeiture if the participating employee's employment with EPCO and its affiliates is terminated prior to February 20, 2014, with customary exceptions for death, disability and certain retirements. The risk of forfeiture associated with the Class B limited partner interests in Enterprise LP will also lapse upon certain change of control events.

Unless otherwise agreed to by EPCO, EPCO Holdings and a majority in interest of the Class B limited partners of Enterprise LP, Enterprise LP will terminate at the earlier of February 20, 2014 (six years from the date of the agreement) or a change in control of us or Enterprise GP Holdings. Enterprise LP has the following material terms regarding its quarterly cash distribution to partners:

- Distributions of cash flow - Each quarter, 100% of the cash distributions received by Enterprise LP from Enterprise GP Holdings and us will be distributed to the Class A limited partner until EPCO Holdings has received an amount equal to the Class A preferred return (as defined below), and any remaining distributions received by Enterprise LP will be distributed to the Class B limited partners. The Class A preferred return equals the Class A capital base (as defined below) multiplied by 5.0% per annum. The Class A limited partner's capital base equals the amount of any contributions of cash or cash equivalents made by the Class A limited partner to Enterprise LP, plus any unpaid Class A preferred return from prior periods, less any distributions made by Enterprise LP of proceeds from the sale of units owned by Enterprise LP (as described below).

- Liquidating Distributions - Upon liquidation of Enterprise LP, units having a fair market value equal to the Class A limited partner capital base will be distributed to EPCO Holdings, plus any accrued Class A preferred return for the quarter in which liquidation occurs. Any remaining units will be distributed to the Class B limited partners.

- Sale Proceeds - If Enterprise LP sells any units that it beneficially owns, the sale proceeds will be distributed to the Class A limited partner and the Class B limited partners in the same manner as liquidating distributions described above.

Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure*.**

None.

Item 9A. ***Controls and Procedures*.**

Disclosure controls and procedures

Our management, with the participation of the chief executive officer ("CEO") and chief financial officer ("CFO") of our general partner, has evaluated the effectiveness of our disclosure controls and procedures, including internal controls over financial reporting, as of December 31, 2007. This evaluation concluded that our disclosure controls and procedures, including internal controls over financial reporting, are effective to provide us with a reasonable assurance that the information required to be disclosed in reports filed with the SEC is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. Our management noted no material weaknesses in the design or operation of our internal controls over financial reporting that are likely to adversely affect our ability to record, process, summarize and report financial information. In addition, no fraud involving management or employees who have a significant role in our internal controls over financial reporting was detected.

The disclosure controls and procedures are also designed to provide reasonable assurance that such information is accumulated and communicated to our management, including the CEO and CFO of our general partner, as appropriate to allow such persons to make timely decisions regarding required disclosures.

Our management does not expect that our disclosure controls and procedures will prevent all errors and all fraud. The design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Based on the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within Enterprise Products Partners have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple errors or mistakes. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the controls. The design of any system of controls is also based in part upon certain assumptions about the likelihood of future events. Therefore, a control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Internal control over financial reporting

Our internal controls over financial reporting are designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our financial statements in accordance with GAAP. These internal controls over financial reporting were designed under the supervision of our management, including the CEO and CFO of our general partner, and include policies and procedures that:

(i) pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of our assets,

(ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP, and that our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and

(iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on our financial statements.

In accordance with Item 308 of SEC Regulation S-K, management is required to provide an annual report regarding internal controls over our financial reporting. This report, which includes management's assessment of the effectiveness of our internal controls over financial reporting, is found elsewhere in this Item 9A.

There were no changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) or in other factors during the fourth quarter of 2007, that have materially affected or are reasonably likely to materially affect our internal controls over financial reporting.

The certifications of our general partner's CEO and CFO required under Sections 302 and 906 of the Sarbanes-Oxley Act of 2002 have been included as exhibits to this annual report on Form 10-K.

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING AS OF DECEMBER 31, 2007

The management of Enterprise Products Partners L.P. and its consolidated subsidiaries, including its Chief Executive Officer and Chief Financial Officer, is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934, as amended. Our internal control system was designed to provide reasonable assurance to Enterprise Products Partners' management and board of directors regarding the preparation and fair presentation of published financial statements. However, our management does not represent that our disclosure controls and procedures or internal controls over financial reporting will prevent all error and all fraud. A control system, no matter how well conceived and operated, can provide only a reasonable, not an absolute, assurance that the objectives of the control system are met.

Our management assessed the effectiveness of Enterprise Products Partners' internal control over financial reporting as of December 31, 2007. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") in Internal Control—Integrated Framework. This assessment included design effectiveness and operating effectiveness of internal controls over financial reporting as well as the safeguarding of assets. Based on our assessment, we believe that, as of December 31, 2007, Enterprise Products Partners' internal control over financial reporting is effective based on those criteria.

Our Audit, Conflicts and Governance Committee is composed of directors who are not officers or employees of our general partner. It meets regularly with members of management, the internal auditors and the representatives of the independent registered public accounting firm to discuss the adequacy of Enterprise Products Partners' internal controls over financial reporting, financial statements and the nature, extent and results of the audit effort. Management reviews with the Audit, Conflicts and Governance Committee all of Enterprise Products Partners' significant accounting policies and assumptions affecting the results of operations. Both the independent registered public accounting firm and internal auditors have direct access to the Audit, Conflicts and Governance Committee without the presence of management.

Our independent registered public accounting firm has issued an attestation report on our internal control over financial reporting. That report is included under Item 9A of this annual report.

Pursuant to the requirements of Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934, as amended, this Annual Report on Internal Control Over Financial Reporting has been signed below by the following persons on behalf of the registrant and in the capacities indicated below on February 29, 2008.

/s/ Michael A. Creel
Name: Michael A. Creel
Title: Chief Executive Officer of our general partner, Enterprise Products GP, LLC

/s/ W. Randall Fowler
Name: W. Randall Fowler
Title: Chief Financial Officer of our general partner, Enterprise Products GP, LLC

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Enterprise Products GP, LLC and
Unitholders of Enterprise Products Partners L.P.
Houston, Texas

We have audited the internal control over financial reporting of Enterprise Products Partners LP and subsidiaries (the "Company") as of December 31, 2007, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company’s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management’s Annual Report on Internal Control over Financial Reporting as of December 31, 2007. Our responsibility is to express an opinion on the Company’s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company’s internal control over financial reporting is a process designed by, or under the supervision of, the company’s principal executive and principal financial officers, or persons performing similar functions, and effected by the company’s board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company’s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet and the related statements of consolidated operations, consolidated comprehensive income, consolidated cash flows, and consolidated partners’ equity as of and for the year ended December 31, 2007 of the Company and our report dated February 28, 2008 expressed an unqualified opinion on those financial statements.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 28, 2008

Item 9B. *Other Information*.

None.

PART III

Item 10. *Directors, Executive Officers and Corporate Governance*.

Partnership Management

As is commonly the case with publicly traded limited partnerships, we do not directly employ any of the persons responsible for the management or operations of our business. These functions are performed by the employees of EPCO pursuant to an administrative services agreement under the direction of the Board of Directors (the "Board") and executive officers of EPGP. For a description of the administrative services agreement, see "Certain Relationships and Related Transactions — Relationship with EPCO" under Item 13 of this annual report.

The executive officers of our general partner are elected for one-year terms and may be removed, with or without cause, only by the Board. Our unitholders do not elect the officers or directors of our general partner. Dan. L. Duncan, through his indirect control of EPGP, has the ability to elect, remove and replace at any time, all of the officers and directors of our general partner. Each member of the Board of our general partner serves until such member's death, resignation or removal. The employees of EPCO who served as directors of EPGP were Messrs. Dan L. Duncan, Michael A. Creel, W. Randall Fowler, Ralph S. Cunningham and Richard H. Bachmann.

Because we are a limited partnership and meet the definition of a "controlled company" under the listing standards of the NYSE, we are not required to comply with certain requirements of the NYSE. Accordingly, we have elected to not comply with Section 303A.01 of the NYSE Listed Company Manual, which would require that the Board of our general partner be comprised of a majority of independent directors. In addition, we have elected to not comply with Sections 303A.04 and 303A.05 of the NYSE Listed Company Manual, which would require that the Board of our general partner maintain a Nominating Committee and a Compensation Committee, each consisting entirely of independent directors.

Notwithstanding any contractual limitation on its obligations or duties, EPGP is liable for all debts we incur (to the extent not paid by us), except to the extent that such indebtedness or other obligations are non-recourse to EPGP. Whenever possible, EPGP intends to make any such indebtedness or other obligations non-recourse to itself.

Under our limited partnership agreement and subject to specified limitations, we will indemnify to the fullest extent permitted by Delaware law, from and against all losses, claims, damages or similar events any director or officer, or while serving as director or officer, any person who is or was serving as a tax matters member or as a director, officer, tax matters member, employee, partner, manager, fiduciary or trustee of our partnership or any of our affiliates. Additionally, we will indemnify to the fullest extent permitted by law, from and against all losses, claims, damages or similar events any person who is or was an employee (other than an officer) or agent of our partnership.

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Corporate Governance

We are committed to sound principles of governance. Such principles are critical for us to achieve our performance goals, and maintain the trust and confidence of investors, employees, suppliers, business partners and stakeholders.

A key element for strong governance is independent members of the Board of Directors. Pursuant to the NYSE listing standards, a director will be considered independent if the Board determines that he or she does not have a material relationship with EPGP or us (either directly or as a partner, unitholder or officer of an organization that has a material relationship with EPGP or us). Based on the foregoing, the Board has affirmatively determined that Messrs. Rex C. Ross, Charles M. Rampacek and E. William Barnett are "independent" directors under the NYSE rules.

As required by the Sarbanes-Oxley Act of 2002, the SEC adopted rules that direct national securities exchanges and associations to prohibit the listing of securities of a public company if its audit committee members do not satisfy a heightened independence standard. In order to meet this standard, members of such audit committees may not receive any consulting fee, advisory fee or other compensation from the public company other than fees for service as a director or committee member and may not be considered an affiliate of the public company. Neither EPGP nor any individual member of its ACG Committee has relied on any exemption in the NYSE rules to establish such individual's independence. Based on the foregoing criteria, the Board has affirmatively determined that all members of its ACG Committee satisfy this heightened independence requirement.

Code of Conduct and Ethics and Corporate Governance Guidelines

EPGP has adopted a "Code of Conduct" that applies to all directors, officers and employees. This code sets out our requirements for compliance with legal and ethical standards in the conduct of our business, including general business principles, legal and ethical obligations, compliance policies for specific subjects, obtaining guidance, the reporting of compliance issues and discipline for violations of the code.

Our Code of Conduct also establishes policies applicable to our chief executive officer, chief financial officer, principal accounting officer and senior financial and other managers to prevent wrongdoing and to promote honest and ethical conduct, including ethical handling of actual and apparent conflicts of interest, compliance with applicable laws, rules and regulations, full, fair, accurate, timely and understandable disclosure in public communications and prompt internal reporting of violations of the code.

Governance guidelines, together with committee charter, provide the framework for effective governance. The Board has adopted the *Governance Guidelines of Enterprise Products Partners,* which address several matters, including qualifications for directors, responsibilities of directors, retirement of directors, the composition and responsibility of ACG Committee, the conduct and frequency of board and committee meetings, management succession, director access to management and outside advisors, director compensation, director orientation and continuing education, and annual self-evaluation of the board. The Board recognizes that effective governance is an on-going process, and thus, the Board will review the Governance Guidelines of Duncan Energy Partners annually or more often as deemed necessary.

We provide access through our website at www.epplp.com to current information relating to governance, including the Code of Conduct, the Governance Guidelines of Enterprise Products Partners and other matters impacting our governance principles. You may also contact our investor relations department at (866) 230-0745 for printed copies of these documents free of charge.

ACG Committee

The sole committee of the Board is its ACG Committee. In accordance with NYSE rules and Section 3(a)(58)(A) of the Securities Exchange Act of 1934, the Board has named three of its members to serve on its ACG Committee. The members of the ACG Committee are independent directors, free from any relationship with us or any of our subsidiaries that would interfere with the exercise of independent judgment.

The members of the ACG Committee must have a basic understanding of finance and accounting and be able to read and understand fundamental financial statements, and at least one member of the ACG Committee shall have accounting or related financial management expertise. The members of the ACG Committee are Messrs. Ross, Rampacek and Barnett. The Board has affirmatively determined that Mr. Rampacek satisfies the definition of "audit committee financial expert" as defined in Item 401(h) of Regulation S-K promulgated by the SEC.

The ACG Committee’s duties are addressing audit and conflicts-related items and general corporate governance. From an audit and conflicts standpoint, the primary responsibilities of the ACG Committee include:

- review potential conflicts of interest, including related party transactions;
- monitoring the integrity of our financial reporting process and related systems of internal control;
- ensuring our legal and regulatory compliance and that of EPGP;
- overseeing the independence and performance of our independent public accountant;
- approving all services performed by our independent public accountant;
- providing for an avenue of communication among the independent public accountant, management, internal audit function and the Board;
- encouraging adherence to and continuous improvement of our policies, procedures and practices at all levels;
- reviewing areas of potential significant financial risk to our businesses; and
- approving awards granted under our long-term incentive plans.

If the Board believes that a particular matter presents a conflict of interest and proposes a resolution, the ACG Committee has the authority to review such matter to determine if the proposed resolution is fair and reasonable to us. Any matters approved by the ACG Committee are conclusively deemed to be fair and reasonable to our business, approved by all of our partners and not a breach by EPGP or the Board of any duties they may owe us or our unitholders.

Pursuant to its formal written charter, the ACG Committee has the authority to conduct any investigation appropriate to fulfilling its responsibilities, and it has direct access to our independent public accountants as well as any EPCO personnel whom it deems necessary in fulfilling its responsibilities. The ACG Committee has the ability to retain, at our expense, special legal, accounting or other consultants or experts it deems necessary in the performance of its duties.

From a governance standpoint, the ACG Committee’s primary duties and responsibilities are to develop and recommend to the Board a set of governance principles applicable to us and review such guidelines from time to time, making any changes that the ACG Committee deems necessary. The ACG Committee assists the Board in fulfilling its oversight responsibilities.

A copy of the ACG Committee charter is available on our website, www.epplp.com. You may also contact our investor relations department at (866) 230-0745 for a printed copy of this document free of charge.

NYSE Corporate Governance Listing Standards

On April 2, 2007, Robert G. Phillips, our chief executive officer on such date, certified to the NYSE (as required by Section 303A.12(a) of the NYSE Listed Company Manual) that he was not aware of any violation by us of the NYSE's Corporate Governance listing standards as of April 2, 2007.

Executive Sessions of Non-Management Directors

The Board holds regular executive sessions in which non-management directors meet without any members of management present. The purpose of these executive sessions is to promote open and candid discussion among the non-management directors. During such executive sessions, one director is designated as the "presiding director," who is responsible for leading and facilitating such executive sessions. Currently, the presiding director is Mr. Barnett.

In accordance with NYSE rules, we have established a toll-free, confidential telephone hotline (the "Hotline") so that interested parties may communicate with the presiding director or with all the non-management directors as a group. All calls to this Hotline are reported to the chairman of the ACG Committee, who is responsible for communicating any necessary information to the other non-management directors. The number of our confidential Hotline is (877) 888-0002.

Directors and Executive Officers of EPGP

The following table sets forth the name, age and position of each of the directors and executive officers of EPGP at February 29, 2008. Each executive officer holds the same respective office shown below in the general partner of the Operating Partnership.

Name	Age	Position with EPGP
Dan L. Duncan (1)	75	Director and Chairman
Michael A. Creel (1)	54	Director, President and Chief Executive Officer
W. Randall Fowler (1)	51	Director, Executive Vice President and Chief Financial Officer
Richard H. Bachmann (1)	55	Director, Executive Vice President, Chief Legal Officer and Secretary
Dr. Ralph S. Cunningham	67	Director
E. William Barnett (2,3)	75	Director
Rex C. Ross (2)	64	Director
Charles M. Rampacek (2)	64	Director
William Ordemann (1)	48	Executive Vice President and Chief Operating Officer
James H. Lytal (1)	50	Executive Vice President
A.J. Teague (1)	62	Executive Vice President
Gil H. Radtke	46	Senior Vice President
James M. Collingsworth	53	Senior Vice President
Michael J. Knesek (1)	53	Senior Vice President, Controller and Principal Accounting Officer

(1) Executive officer

(2) Member of ACG Committee

(3) Chairman of ACG Committee

The following information presents a brief history of the business experience of our directors and executive officers serving as of December 31, 2007:

Dan L. Duncan. Mr. Duncan was elected Chairman and a Director of EPGP in April 1998, Chairman and a Director of the general partner of EPO in December 2003, Chairman and a Director of EPE Holdings in August 2005 and Chairman and a Director of DEP GP in October 2006. Mr. Duncan served as the sole Chairman of EPCO from 1979 to December 2007. Mr. Duncan now serves as Group Co-Chairman of EPCO with his daughter, Ms. Randa Duncan Williams, also a Director of EPE Holdings. He also serves as a Honorary Trustee of the Board of Trustees of the Texas Heart Institute at Saint Luke's Episcopal Hospital.

Michael A. Creel. Mr. Creel was elected President and Chief Executive Officer of EPGP in August 2007. From June 2000 to August 2007, Mr. Creel served as Chief Financial Officer of EPGP and an Executive Vice President of EPGP from January 2001 to August 2007. Mr. Creel, a certified public accountant, also served as a Senior Vice President of EPGP from November 1999 to January 2001.

In December 2007, Mr. Creel was elected Group Vice Chairman and Chief Financial Officer of EPCO. Prior to these elections in EPCO, Mr. Creel served as Chief Operating Officer from April 2005 to December 2007 and Chief Financial Officer from June 2000 to April 2005 for EPCO. He also serves as a Director of DEP GP and EPGP since October 2006 and 2005, respectively. Mr. Creel served as President, Chief Executive Officer and a Director of EPE Holdings from August 2005 through August 2007. In October 2005, Mr. Creel was elected a Director of Edge Petroleum Corporation (a publicly traded oil and natural gas exploration and production company).

W. Randall Fowler. Mr. Fowler was elected Executive Vice President and Chief Financial Officer of EPGP, EPE Holdings and DEP GP in August 2007. Mr. Fowler has served as Senior Vice President and Treasurer of EPGP from February 2005 to August 2007 and of DEP GP from October 2006 to August 2007. In February 2006, Mr. Fowler became a Director of EPGP and EPE Holdings and of DEP GP since October 2006. Mr. Fowler also served as Senior Vice President and Chief Financial Officer of EPE Holdings from August 2005 to August 2007.

Mr. Fowler was elected President and Chief Executive Officer of EPCO in December 2007. Prior to these elections, he served as Chief Financial Officer of EPCO from April 2005 to December 2007. Mr. Fowler, a certified public accountant (inactive), joined Enterprise Products Partners as Director of Investor Relations in January 1999.

Richard H. Bachmann. Mr. Bachmann was elected an Executive Vice President, Chief Legal Officer and Secretary of EPGP and a Director of EPGP in February 2006. He previously served as a Director of EPGP from June 2000 to January 2004. Mr. Bachmann has served as a Director of the general partner of EPO since December 2003 and has served as Executive Vice President, Chief Legal Officer and Secretary of EPE Holdings since August 2005.

Mr. Bachmann was elected Group Vice Chairman, Chief Legal Officer and Secretary of EPCO in December 2007. In October 2006, Mr. Bachmann was elected President, Chief Executive Officer and a Director of DEP GP. Mr. Bachmann was also elected a Director of DEP GP in October 2006 and a Director of EPE Holdings in February 2006. Since January 1999, Mr. Bachmann has served as a Director of EPCO. In November 2006, Mr. Bachmann was appointed an independent manager of Constellation Energy Partners LLC. Mr. Bachmann also serves as a member of the audit, compensation and nominating and governance committee of Constellation Energy Partners LLC.

Dr. Ralph S. Cunningham. Dr. Cunningham was elected a Director of EPGP in February 2006 and also served as a Director of EPGP from 1998 until March 2005. In addition to these duties Dr. Cunningham served as Group Executive Vice President and Chief Operating Officer of EPGP from December 2005 to August 2007 and Interim President and Interim Chief Executive Officer from June 2007 to August 2007. Dr. Cunningham was elected President and Chief Executive Officer of EPE Holdings in August 2007. He served as Chairman and a Director of TEPPCO GP from March 2005 until November 2005.

Dr. Cunningham was elected a Group Vice Chairman of EPCO in December 2007 and served as a Director from 1987 to 1997. He serves as a Director of Tetra Technologies, Inc. (a publicly traded energy services and chemical company), EnCana Corporation (a Canadian publicly traded independent oil and natural gas company) and Agrium, Inc. (a Canadian publicly traded agricultural chemicals company). Dr. Cunningham retired in 1997 from CITGO Petroleum Corporation, where he had served as President and Chief Executive Officer since 1995.

E. William Barnett. Mr. Barnett was elected a Director of EPGP in March 2005. Mr. Barnett is a member of our ACG Committee and serves as its Chairman. Mr. Barnett practiced law with Baker Botts

L.L.P. from 1958 until his retirement in 2004. In 1984, he became Managing Partner of Baker Botts L.L.P. and continued in that role for fourteen years until 1998. He was Senior Counsel to the firm from 1998 until June 2004, when he retired from the firm. Mr. Barnett served as Chairman of the Board of Trustees of Rice University from 1996 to July 2005.

Mr. Barnett is a Life Trustee of The University of Texas Law School Foundation; a Director of St. Luke's Episcopal Health System; and a Director and former Chairman of the Houston Zoo, Inc. (the operating arm of the Houston Zoo). He is a Director of Reliant Energy, Inc. (a publicly traded electric services company) and Westlake Chemical Corporation (a publicly traded chemical company). Mr. Barnett is Chairman of the Advisory Board of the Baker Institute for Public Policy at Rice University and a Director and former Chairman of the Greater Houston Partnership. Mr. Barnett served as a Trustee of the Baylor College of Medicine from 1993 until 2004.

Rex C. Ross. Mr. Ross was elected a Director of EPGP in October 2006 and is a member of its ACG Committee. Mr. Ross serves as a Director of Schlumberger Technology Corporation, the holding company for all Schlumberger Limited assets and entities in the United States. Prior to his executive retirement from Schlumberger Limited in May 2004, Mr. Ross held a number of executive management positions during his 11-year career with the company, including President of Schlumberger Oilfield Services North America; President, Schlumberger GeoQuest; and President of SchlumbergerSema North & South America. Mr. Ross also serves on the board of directors of Gulfmark Offshore, Inc. (a publicly traded offshore marine services company) and is a member of its Governance Committee.

Charles M. Rampacek. Mr. Rampacek was elected a Director of EPGP in October 2006 and is a member of its ACG Committee. Mr. Rampacek is currently a business and management consultant in the energy industry. Mr. Rampacek served as Chairman, Chief Executive Officer and President of Probex Corporation ("Probex"), an energy technology company that developed a proprietary used oil recovery process, from 2000 until his retirement in 2003. Prior to joining Probex Corporation, Mr. Rampacek was President and Chief Executive Officer of Lyondell-Citgo Refining L.P, a manufacturer of petroleum products, from 1996 through 2000. From 1982 to 1995, he held various executive positions with Tenneco Inc. and its energy-related subsidiaries, including President of Tenneco Gas Transportation Company, Executive Vice President of Tenneco Gas Operations and Senior Vice President of Refining and Supply. Mr. Rampacek also spent 16 years with Exxon Company USA, where he held various supervisory and management positions. Mr. Rampacek has been a Director of Flowserve Corporation since 1998 and is Chairman of its Corporate Governance and Nominating Committee and a member of its Organization and Compensation Committee.

In 2005, two complaints requesting recovery of certain costs were filed against former officers and directors of Probex Corporation as a result of the bankruptcy of Probex in 2003. These complaints were defended under Probex's director and officer insurance by AIG and settlement was reached and paid by AIG with bankruptcy court approval in the first half of 2006. An additional complaint was filed in 2005 against noteholders of certain Probex debt of which Mr. Rampacek was one. A settlement of $2,000 was reached and approved by the bankruptcy court in the first half of 2006.

William Ordemann. Mr. Ordemann was elected an Executive Vice President and the Chief Operating Officer of EPGP in August 2007. He previously served as a Senior Vice President of EPGP from September 2001 to August 2007 and was a Vice President of EPGP from October 1999 to September 2001. Mr. Ordemann joined us in connection with our purchase of certain midstream energy assets from affiliates of Shell Oil Company in 1999. Prior to joining us, he was a Vice President of Shell Midstream Enterprises, LLC from January 1997 to February 1998, and Vice President of Tejas Natural Gas Liquids, LLC from February 1998 to September 1999.

James H. Lytal. Mr. Lytal was elected an Executive Vice President of EPGP in September 2004. Mr. Lytal served as a Director of the general partner of GulfTerra Energy Partners, L.P. from August 1994 until September 2004, and as President of GulfTerra and its general partner from July 1995 until September 2004. He served as a Senior Vice President of GulfTerra and its general partner from August 1994 to June 1995. Prior to joining GulfTerra, Mr. Lytal served in various capacities with the oil and gas exploration and production and natural gas pipeline businesses of United Gas Pipeline Company, Texas Oil and Gas, Inc. and American Pipeline Company

A.J. Teague. Mr. Teague was elected an Executive Vice President of EPGP in November 1999. Mr. Teague joined us in connection with our purchase of certain midstream energy assets from affiliates of Shell Oil Company in 1999. From 1998 to 1999, Mr. Teague served as President of Tejas Natural Gas Liquids, LLC

Gil H. Radtke. Mr. Radtke was elected a Senior Vice President of EPGP in February 2002. Mr. Radtke joined us in connection with our purchase of Diamond-Koch's storage and propylene fractionation assets in 2002. Before joining us, Mr. Radtke served as president of the Diamond-Koch joint venture from 1999 to 2002, where he was responsible for its storage, propylene fractionation, pipeline and NGL fractionation businesses. From 1997 to 1999 he was Vice President, Petrochemicals and Storage of Diamond-Koch. In October 2006, Mr. Radtke was elected a Senior Vice President, Chief Operating Officer and a Director of the general partner of Duncan Energy Partners.

James M. Collingsworth. Mr. Collingsworth was elected a Vice President of EPGP in November 2001 and subsequently promoted to a Senior Vice President in November 2002. Mr. Collingsworth joined us in connection with our acquisition of the Mid-America and Seminole Pipeline Systems in 2002. Before joining us, he served as a board member of Texaco Canada Petroleum Inc. from July 1998 to October 2001 and was employed by Texaco from 1991 to 2001 in various management positions, including Senior Vice President of NGL Assets and Business Services from July 1998 to October 2001.

Michael J. Knesek. Mr. Knesek, a certified public accountant, was elected a Senior Vice President of EPGP in February 2005 having served as a Vice President of EPGP since August 2000. Mr. Knesek has been the Principal Accounting Officer and Controller of EPGP since August 2000, EPE Holdings since August 2005 and DEP GP since October 2006. He has served as Senior Vice President of EPE Holdings since August 2005 and of DEP GP since October 2006. Mr. Knesek has been the Controller of EPCO since 1990 and currently serves as one of its Senior Vice Presidents.

Section 16(a) Beneficial Ownership Reporting Compliance

Under federal securities laws, EPGP, directors and executive officers of EPGP, and certain other officers, and any persons holding more than 10% of our common units are required to report their ownership of common units and any changes in their ownership levels to us and the SEC. Specific due dates for these reports have been established by regulation, and we are required to disclose in this annual report any failure to file this information within the specified timeframes. With the exception of the following late filing, all such reporting was done in a timely manner in 2007.

The spouse of Mr. Rex Ross serves as trustee for a trust that benefits, in part, certain of his immediate family members. This trust holds 4,500 common units of Enterprise that have not been previously reported for Section 16 purposes. On November 14, 2007, this trust purchased 1,000 common units of Enterprise at an average price of $31.95 per unit. The remaining 3,500 common units held in the trust were purchased more than six months before Mr. Ross became a Director of EPGP and should have been reflected on his Form 3, which was filed on October 23, 2006. These trust holdings were properly reflected on a Form 4 for Mr. Ross on Friday, February 29, 2008.

Item 11. *Executive Compensation*.

Executive Officer Compensation

We do not directly employ any of the persons responsible for managing our partnership. Instead, we are managed by our general partner, the executive officers of which are employees of EPCO. Our reimbursement of EPCO's compensation costs is governed by the administrative services agreement with EPCO (see Item 13).

Summary Compensation Table

The following table presents consolidated compensation amounts paid, accrued or otherwise expensed by us with respect to the years ended December 31, 2007 and 2006 for our general partner's Chief Executive Officer ("CEO"), Chief Financial Officer ("CFO") and three other most highly compensated executive officers as of December 31, 2007. We also include Robert G. Phillips and Dr. Ralph S. Cunningham, both of whom served as our CEO during 2007 prior to Michael A. Creel's appointment to this position effective August 1, 2007. Collectively, these seven individuals were our "Named Executive Officers" for 2007. Compensation paid or awarded by us with respect to such Named Executive Officers reflects only that portion of compensation paid by EPCO allocated to us pursuant to an administrative services agreement, including an allocation of a portion of the cost of EPCO's equity-based long-term incentive plans.

Name and Principal Position	Year	Salary ($)	Bonus ($) (5)	Unit Awards ($) (6)	Option Awards ($) (7)	All Other Compensation ($) (8)	Total ($)
Michael A. Creel (1)	2007	$361,808	$365,370	$517,707	$ 44,449	$ 108,017	$1,397,351
	2006	306,000	125,000	303,622	23,613	71,812	830,047
Robert G. Phillips (former CEO) (2)	2007	372,300	—	202,755	166,498	8,950,109	9,691,662
	2006	722,500	300,000	660,270	357,209	150,984	2,190,963
Dr. Ralph S. Cunningham (former CEO) (3)	2007	281,828	171,190	231,645	23,564	37,896	746,123
	2006	478,667	250,000	52,815	13,707	33,208	828,397
W. Randall Fowler (4)	2007	213,145	129,720	297,976	25,033	53,425	719,299
	2006	215,875	70,000	173,874	14,242	40,601	514,592
James H. Lytal	2007	386,250	210,000	730,634	77,980	162,494	1,567,358
	2006	367,500	187,500	455,462	47,227	101,639	1,159,328
A. J. Teague	2007	445,660	300,000	587,905	77,980	110,336	1,521,881
	2006	428,480	250,000	299,984	47,227	69,563	1,095,254
Richard H. Bachmann	2007	306,900	186,000	454,130	38,990	94,752	1,080,772
	2006	177,420	75,000	182,174	14,168	43,088	491,850

(1) Mr. Creel was appointed our Chief Executive Officer effective August 1, 2007. He served as our Chief Financial Officer through August 1, 2007. Amounts presented for the years ended December 31, 2007 and 2006 reflect his tenure in both positions.

(2) Mr. Phillips served as our Chief Executive Officer until his resignation effective June 30, 2007. The amount presented as "All Other Compensation" for 2007 includes a separation payment of $8,822,400.

(3) Dr. Cunningham served as our Acting Chief Executive Officer from June 30, 2007 to August 1, 2007. Amounts presented for the years ended December 31, 2007 and 2006 reflect his total compensation allocated to us with respect to these periods.

(4) Mr. Fowler was appointed our Chief Financial Officer effective August 1, 2007. Amounts presented for the years ended December 31, 2007 and 2006 reflect his total compensation allocated to us with respect to these periods.

(5) Amounts represent discretionary annual cash awards accrued for the years ended December 31, 2007 and 2006. Cash awards are paid in February of the following year (e.g. 2007 cash awards are paid in February 2008).

(6) Amounts represent expense recognized in accordance with SFAS 123(R) for the years ended December 31, 2007 and 2006 with respect to restricted unit and Employee Partnership awards.

(7) Amounts represent expense recognized in accordance with SFAS 123(R) for the years ended December 31, 2007 and 2006 with respect to unit options.

(8) Amounts primarily represent (i) matching contributions under funded, qualified, defined contribution retirement plans, (ii) quarterly distributions paid on equity incentive plan awards and (iii) the imputed value of life insurance premiums paid on behalf of the officer.

(9) Mr. Lytal's total compensation for 2007 includes perquisites totaling $13,111.

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Compensation Discussion and Analysis

With respect to our Named Executive Officers, compensation paid or awarded by us for the last two fiscal years reflects only that portion of compensation paid by EPCO allocated to us pursuant to the administrative services agreement, including an allocation of a portion of the cost of equity-based long-term incentive plans of EPCO. Dan L. Duncan controls EPCO and has ultimate decision-making authority with respect to the compensation of our Named Executive Officers. The following elements of compensation, and EPCO's decisions with respect to determination of payments, are not subject to approvals by our Board or the ACG Committee. Awards under EPCO's long-term incentive plans are approved by the ACG Committee. We do not have a separate compensation committee.

As discussed below, the elements of EPCO's compensation program, along with EPCO's other rewards (e.g., benefits, work environment, career development), are intended to provide a total rewards package to employees. The compensation package is designed to reward contributions by employees in support of the business strategies of EPCO and its affiliates at both the partnership and individual levels. With respect to the years ended December 31, 2007 and 2006, EPCO's compensation package for Named Executive Officers did not include any elements based on targeted performance-related criteria.

The primary elements of EPCO's compensation program are a combination of annual cash and long-term equity-based incentive compensation. For the years ended December 31, 2007 and 2006, the elements of compensation for the Named Executive Officers consisted of the following:

- Annual base salary;
- Discretionary annual cash awards;
- Awards under long-term incentive arrangements; and
- Other compensation, including very limited perquisites.

In order to assist Mr. Duncan and EPCO with compensation decisions, our Chief Executive Officer and the Senior Vice President of Human Resources for EPCO formulate preliminary compensation recommendations for all of the Named Executive Officers other than our Chief Executive Officer. Mr. Duncan, after consulting with the Senior Vice President of Human Resources for EPCO, independently makes compensation decisions with respect to our Chief Executive Officer. EPCO takes note of market data for determining relevant compensation levels and compensation program elements through the review of and, in certain cases, participation in, various relevant compensation surveys. Mr. Duncan and EPCO do not use any formula or specific performance-based criteria for our Named Executive Officers in connection with services performed for us. All compensation determinations are discretionary and, as noted above, subject to Mr. Duncan's ultimate decision-making authority.

The discretionary cash awards paid to each of our Named Executive Officers were determined by consultation among Mr. Duncan, our Chief Executive Officer and the Senior Vice President of Human Resources for EPCO, subject to Mr. Duncan's final determination. These cash awards, in combination with annual base salaries, are intended to yield competitive total cash compensation levels for the Named Executive Officers and drive performance in support of our business strategies, as well as the performance of other EPCO affiliates for which the Named Executive Officers perform services. It is EPCO's general policy to pay these awards during the first quarter of each year.

The equity awards granted under the EPCO 1998 Plan to our Named Executive Officers were determined by consultation among Mr. Duncan, our Chief Executive Officer and the Senior Vice President of Human Resources for EPCO, and were approved by our general partner's ACG Committee. These awards (restricted units and unit options) are intended to align the long-term interests of the executive officers with those of our unitholders. It is EPCO's general policy to recommend, and the ACG Committee typically approves, these grants to employees during the second quarter of each fiscal year. In addition, our Named Executive Officers are Class B limited partners in certain of the Employee Partnerships. Mr. Duncan approves the issuance of all limited partnership interests in such Employee Partnerships to our Named Executive Officers. See "Summary of Long-Term Incentive Arrangements Underlying 2007 Award Grants" within this Item 11 for information regarding the long-term incentive plans. See Notes 2 and 5 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding the accounting for such awards.

EPCO generally does not pay for perquisites for any of our Named Executive Officers, other than reimbursement of certain parking expenses, and expects to continue its policy of covering very limited perquisites allocable to our Named Executive Officers. EPCO also makes matching contributions under its 401(k) plan for the benefit of our Named Executive Officers in the same manner as it does for other EPCO employees.

EPCO does not offer our Named Executive Officers a defined benefit pension plan. Also, none of our Named Executive Officers had nonqualified deferred compensation during the years ended December 31, 2007 or 2006.

We believe that each of the base salary, cash awards, and incentive awards fit the overall compensation objectives of us and of EPCO, as stated above (i.e., to provide competitive compensation opportunities to align and drive employee performance toward the creation of sustained long-term unitholder value, which will also allow us to attract, motivate and retain high quality talent with the skills and competencies required by us).

Compensation Committee Report

We do not have a separate compensation committee. As discussed in the Compensation Discussion and Analysis, we do not directly employ or compensate our Named Executive Officers. Rather, under the administrative services agreement with EPCO, we reimburse EPCO for the compensation of our executive officers. Accordingly, to the extent that decisions are made regarding the compensation policies pursuant to which our Named Executive Officers are compensated, they are made by Dan L. Duncan and EPCO (except for equity awards under long-term incentive plans, as discussed above), and not by our Board of Directors.

In light of the foregoing, the Board of Directors of our general partner has reviewed and discussed the Compensation Discussion and Analysis with management. Based on our review of and discussion with management with respect to the Compensation Discussion and Analysis, we determined that the Compensation Discussion and Analysis be included in this Report.

Submitted by: Dan L. Duncan
Michael A. Creel
W. Randall Fowler
Richard H. Bachmann
Dr. Ralph S. Cunningham
E. William Barnett
Charles M. Rampacek
Rex C. Ross

Notwithstanding anything to the contrary set forth in any previous filings under the Securities Act, as amended, or the Exchange Act, as amended, that incorporate future filings, including this Report, in whole or in part, the foregoing report shall not be incorporated by reference into any such filings.

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Grants of Plan-Based Awards in Fiscal Year 2007

The following table presents information concerning each grant of a plan-based award made to a Named Executive Officer in 2007. The restricted unit and unit option awards granted during 2007 were under EPCO's 1998 Long-Term Incentive Plan (the "1998 Plan"). See "Summary of Long-Term Incentive Arrangements Underlying 2007 Award Grants" within this Item 11 for additional information regarding EPCO's long-term incentive plans.

Name	Grant Date	Estimated Future Payouts Under Equity Incentive Plan Awards Threshold (#)	Target (#)	Maximum (#)	Exercise or Base Price of Option Awards ($/Unit)	Grant Date Fair Value of Unit and Option Awards ($) (1)
Restricted unit awards: (2)						
Michael A. Creel	5/29/07	—	26,500	—	—	$ 481,926
Dr. Ralph S. Cunningham	5/29/07	—	26,500	—	—	434,812
W. Randall Fowler	5/29/07	—	17,000	—	—	235,686
James H. Lytal	5/29/07	—	26,500	—	—	820,440
A.J. Teague	5/29/07	—	26,500	—	—	820,440
Richard H. Bachmann	5/29/07	—	26,500	—	—	341,697
Unit option awards: (3)						
Michael A. Creel	5/29/07	—	60,000	—	$30.96	94,454
Dr. Ralph S. Cunningham	5/29/07	—	60,000	—	$30.96	85,224
W. Randall Fowler	5/29/07	—	45,000	—	$30.96	54,005
James H. Lytal	5/29/07	—	60,000	—	$30.96	160,800
A.J. Teague	5/29/07	—	60,000	—	$30.96	160,800
Richard H. Bachmann	5/29/07	—	60,000	—	$30.96	66,973
EPE Unit III profits interest award: (4)						
Michael A. Creel	5/7/07	—	—	—	—	1,032,387
Dr. Ralph S. Cunningham	5/7/07	—	—	—	—	931,504
W. Randall Fowler	5/7/07	—	—	—	—	787,033
James H. Lytal	5/7/07	—	—	—	—	1,464,621
A.J. Teague	5/7/07	—	—	—	—	1,464,621
Richard H. Bachmann	5/7/07	—	—	—	—	732,021

(1) Amounts presented reflect that portion of grant date fair value allocable to us based on the percentage of time each Named Executive Officer spent on our consolidated business activities during 2007. Based on current allocations, we estimate that the consolidated compensation expense we record for each Named Executive Officer with respect to these awards will equal these amounts over time.

(2) For the period in which the restricted unit awards were outstanding during 2007, we recognized a total of $0.4 million of consolidated compensation expense related to these awards. The remaining portion of grant date fair value will be recognized as expense in future periods.

(3) For the period in which the unit option awards were outstanding during 2007, we recognized a total of $72 thousand of consolidated compensation expense related to these awards. The remaining portion of grant date fair value will be recognized as expense in future periods.

(4) For the period in which the profits interest awards were outstanding during 2007, we recognized a total of $1.0 million of consolidated compensation expense related to these awards. The remaining portion of grant date fair value will be recognized as expense in future periods.

The fair value amounts shown in the preceding table are based on certain assumptions and considerations made by management. The grant date fair values of restricted unit awards issued in May 2007 were based on a market price of Enterprise Products Partners' common units of $30.96 per unit.

The grant date fair values of unit option awards issued in May 2007 were based on the following assumptions: (i) expected life of the options of seven years; (ii) risk-free interest rate of 4.8%; (iii) an expected distribution yield on our common units of 8.4%; and (iv) an expected unit price volatility of our common units of 23.2%.

The fair value of the EPE Unit III profits interest awards issued in May 2007 was based on the following assumptions: (i) remaining life of the award of five years; (ii) risk-free interest rate of 4.6%; (iii) an expected distribution yield on Enterprise GP Holdings' units of 4.1% and (iv) an expected unit price volatility of Enterprise GP Holdings' units of 17.6%.

Awards granted to Robert G. Phillips in May 2007 were cancelled in connection with his $8.8 million cash separation payment paid in June 2007.

Summary of Long-Term Incentive Arrangements Underlying 2007 Award Grants

The following information summarizes the types of awards granted to our Named Executive Officers during the year ended December 31, 2007. For detailed information regarding our accounting for unit-based awards, see Note 5 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Unit option awards. Under EPCO's 1998 Plan, non-qualified, incentive options to purchase a fixed number of our common units may be granted to EPCO's key employees who perform management, administrative or operational functions for us or our affiliates. When issued, the exercise price of each option grant is equivalent to the market price of the underlying equity on the date of grant. In general, options granted under the 1998 Plan have a vesting period of four years and remain exercisable for ten years from the date of grant. In order to fund its obligations under the 1998 Plan, EPCO may purchase common units at fair value either in the open market or directly from us. When employees exercise unit options, we reimburse EPCO for the cash difference between the strike price paid by the employee and the actual purchase price paid by EPCO for the units issued to the employee.

Restricted unit awards. Under the 1998 Plan, EPCO's key employees who perform management, administrative or operational functions for us or our affiliates may be awarded restricted common units. In general, our restricted unit awards allow recipients to acquire the underlying common units (at no cost to the recipient) once a defined vesting period expires, subject to certain forfeiture provisions. The restrictions on such nonvested units generally lapse four years from the date of grant. The fair value of restricted units is based on the market price of the underlying common units on the date of grant less an allowance for estimated forfeitures. Each recipient is also entitled to cash distributions equal to the product of the number of restricted units outstanding for the participant and the cash distribution per unit paid by us to our unitholders.

As used in the context of the EPCO plans, the term "restricted unit" represents a time-vested unit under SFAS 123(R). Such awards are non-vested until the required service period expires.

Phantom unit awards. The EPCO 1998 Plan also provides for the issuance of phantom unit awards. These liability awards are automatically redeemed for cash based on the vested portion of the fair market value of the phantom units at redemption dates in each award. The fair market value of each phantom unit award is equal to the market closing price of our common units on the redemption date. Each participant is required to redeem their phantom units as they vest, which typically is four years from the date the award is granted. No phantom unit awards have been issued to date under the EPCO 1998 Plan.

The EPCO 1998 Plan also provides for the award of distribution equivalent rights ("DERs") in tandem with its phantom unit awards. A DER entitles the participant to cash distributions equal to the product of the number of phantom units outstanding for the participant and the cash distribution rate paid by us to our unitholders.

Profits interests awards. EPCO formed the Employee Partnerships to serve as long-term incentive arrangements for certain employees of EPCO by providing "profits interests" in the underlying limited partnerships (i.e. EPE Unit I, EPE Unit II and EPE Unit III). Our Named Executive Officers have been granted profits interest awards in EPE Unit I (formed in August 2005), EPE Unit II (formed in December 2006) and EPE Unit III (formed in May 2007). The profits interest awards (or Class B limited partner interests) entitle each holder to participate in the appreciation in value of Enterprise GP Holdings' units and are subject to forfeiture. See Item 13 of this annual report for additional information regarding the Employee Partnerships.

The following table provides information regarding the Named Executive Officers' share of such profits interest at December 31, 2007:

Plan Name	Percentage Ownership of Class B Interests (1)	Estimated Liquidation Value To Be Received by Officer (2)
EPE Unit I: (3)		
Michael A. Creel	7.92%	$1,100,679
W. Randall Fowler	5.32%	739,257
James H. Lytal	5.32%	739,257
A.J. Teague	5.32%	739,257
Richard H. Bachmann	7.92%	1,100,679
EPE Unit II: (4)		
Dr. Ralph S. Cunningham	100.0%	$ 0
EPE Unit III: (5)		
Michael A. Creel	7.63%	$ 0
Dr. Ralph S. Cunningham	7.63%	$ 0
W. Randall Fowler	7.63%	$ 0
James H. Lytal	6.36%	$ 0
A.J. Teague	6.36%	$ 0
Richard H. Bachmann	7.63%	$ 0

(1) Reflects Named Executive Officer share of profits interest at December 31, 2007.

(2) Values based on December 31, 2007 closing price of Enterprise GP Holdings' units of $37.02 per unit and taking into account the terms of liquidation outlined in each Employee Partnership agreement.

(3) At December 31, 2007, the total profits interests of EPE Unit I would have been worth $13.9 million, of which each Named Executive Officer would have received his proportionate share.

(4) The EPE Unit II Class B partnership interest had no liquidation value at December 31, 2007 due to a decrease in the market value of Enterprise GP Holdings' units since the formation of EPE Unit II.

(5) The EPE Unit III Class B partnership interests had no liquidation value at December 31, 2007 due to a decrease in the market value of Enterprise GP Holdings' units since the formation of EPE Unit III.

See Note 25 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report for information regarding the formation of Enterprise Products 2008 Long-Term Incentive Plan in January 2008 and Enterprise Unit L.P. in February 2008.

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Equity Awards Outstanding at December 31, 2007

The following tables present information concerning each Named Executive Officer's nonvested restricted units and unexercised unit options as of December 31, 2007.

		Option Awards			Unit Awards	
Name	Vesting Date	Number of Units Underlying Options Unexercisable (#)	Option Exercise Price ($/Unit)	Option Expiration Date	Number of Units That Have Not Vested (#)	Market Value of Units That Have Not Vested ($)
Restricted unit awards:						
Michael A. Creel	Various (1)	—	—	—	103,053	$3,285,330
Dr. Ralph S. Cunningham	Various (1)	—	—	—	38,500	1,227,380
W. Randall Fowler	Various (1)	—	—	—	58,777	1,873,811
James H. Lytal	Various (1)	—	—	—	86,032	2,742,700
A.J. Teague	Various (1)	—	—	—	60,500	1,928,740
Richard H. Bachmann	Various (1)	—	—	—	103,053	3,285,330
Unit option awards:						
Michael A. Creel:						
May 10, 2004 option grant	5/10/08	35,000	$20.00	5/10/14	—	—
August 4, 2005 option grant	8/04/09	35,000	26.47	8/04/15	—	—
May 1, 2006 option grant	5/01/10	40,000	24.85	5/01/16	—	—
May 29, 2007 option grant	5/29/11	60,000	30.96	5/29/17	—	—
Dr. Ralph S. Cunningham:						
May 1, 2006 option grant	5/01/10	40,000	24.85	5/01/16	—	—
May 29, 2007 option grant	5/29/11	60,000	30.96	5/29/17	—	—
W. Randall Fowler:						
May 10, 2004 option grant	5/10/08	10,000	20.00	5/10/14	—	—
August 4, 2005 option grant	8/04/09	25,000	26.47	8/04/15	—	—
May 1, 2006 option grant	5/01/10	40,000	24.85	5/01/16	—	—
May 29, 2007 option grant	5/29/11	45,000	30.96	5/29/17	—	—
James H. Lytal:						
September 30, 2004 option grant	9/30/08	35,000	23.18	9/30/14	—	—
August 4, 2005 option grant	8/04/09	35,000	26.47	8/04/15	—	—
May 1, 2006 option grant	5/01/10	40,000	24.85	5/01/16	—	—
May 29, 2007 option grant	5/29/11	60,000	30.96	5/29/17	—	—
A.J. Teague:						
May 10, 2004 option grant	5/10/08	35,000	20.00	5/10/14	—	—
August 4, 2005 option grant	8/04/09	35,000	26.47	8/04/15	—	—
May 1, 2006 option grant	5/01/10	40,000	24.85	5/01/16	—	—
May 29, 2007 option grant	5/29/11	60,000	30.96	5/29/17	—	—
Richard H. Bachmann:						
May 10, 2004 option grant	5/10/08	35,000	20.00	5/10/14	—	—
August 4, 2005 option grant	8/04/09	35,000	26.47	8/04/15	—	—
May 1, 2006 option grant	5/01/10	40,000	24.85	5/01/16	—	—
May 29, 2007 option grant	5/29/11	60,000	30.96	5/29/17	—	—

(1) Of the 449,915 restricted units presented in the table, 182,415 vest in 2008, 46,000 vest in 2009, 72,000 vest in 2010, and 149,500 vest in 2011.

The following tables present information concerning each Named Executive Officer's nonvested profits interest awards as of December 31, 2007.

		Option Awards			Unit Awards	
Name	Vesting Date	Number of Units Underlying Options Unexercisable (#)	Option Exercise Price ($/Unit)	Option Expiration Date	Number of Units That Have Not Vested (#)	Market Value of Units That Have Not Vested ($)
EPE Unit I profits interest awards:						
Michael A. Creel	8/30/10	—	—	—	—	1,100,679
W. Randall Fowler	8/30/10	—	—	—	—	739,257
James H. Lytal	8/30/10	—	—	—	—	739,257
A.J. Teague	8/30/10	—	—	—	—	739,257
Richard H. Bachmann	8/30/10	—	—	—	—	1,100,679

Option Exercises and Stock Vested Table

The Named Executive Officers did not exercise any unit options during 2007. In addition, the Named Executive Officers did not vest in any equity-based awards during the year.

Director Compensation

The following table presents information regarding compensation paid to the independent directors of our general partner for the year ended December 31, 2007.

Name	Fees Earned or Paid in Cash ($)	Unit Awards ($) (1)	Option Awards ($) (2)	All Other Compensation ($) (5)	Total ($)
E. William Barnett	$77,500	$68,562	$32,948 (3)	$3,933	$182,943
Rex C. Ross	62,500	19,575	34,530 (4)	890	117,496
Charles M. Rampacek	62,500	19,575	34,530 (4)	890	117,496

(1) In November 2007, each of the restricted unit grants made to our independent directors was amended to provide that the restricted units subject to such grants would immediately vest. The amounts presented for each director represent the expense recognized by us related to such restricted units during the year ended December 31, 2007. The number of restricted units that vested for each independent director was as follows: Mr. Barnett, 2,154; Mr. Ross, 615; and Mr. Rampacek, 615.

(2) Amounts presented reflect the compensation expense recognized by EPGP related to unit appreciation rights ("UARs") granted in 2006 under letter agreements. The UARs are accounted for as liability awards under SFAS 123(R) since they will be settled with cash.

(3) At December 31, 2007, the fair value of UARs granted to Mr. Barnett was $96 thousand.

(4) At December 31, 2007, the fair value of UARs granted to each of Mr. Ross and Mr. Rampacek was $102 thousand.

(5) Amounts primarily represent the quarterly cash distributions each independent director received from restricted unit awards prior to the vesting of such awards in November 2007.

Neither we nor EPGP provide any additional compensation to employees of EPCO who serve as directors of EPGP. The employees of EPCO who served as directors of EPGP during 2007 were Messrs. Duncan, Creel, Fowler, Bachmann, Cunningham and Phillips.

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Currently, EPGP's three independent directors, Messrs. Barnett, Ross and Rampacek, are provided cash compensation for their services as follows:

- Each independent director receives $75,000 in cash annually. Prior to August 2007, the annual retainer was $50,000 in cash and $25,000 worth of restricted units.
- If the individual serves as chairman of a committee of the Board of Directors, then he receives an additional $15,000 in cash annually.

The independent directors of our general partner have also received unit-based compensation in the form of UARs. These awards consist of letter agreements with each of the independent directors and are not part of any established long-term incentive plan of the EPCO group of companies. The awards are based upon an incentive plan of EPE Holdings, and are made in the form of UAR grants for non-employee directors. The compensation expense associated with these awards is recognized by EPGP. These UARs entitle the directors to receive a cash amount in the future equal to the excess, if any, of the fair market value of Enterprise GP Holdings' units (determined as of a future vesting date) over the grant date price of such units. If a director resigns prior to vesting, his UAR awards are forfeited.

In August 2006, Mr. Barnett was granted 10,000 UARs under the letter agreement format. The grant date price of these rights was $35.71 per unit. These awards vest in August 2011 or on the date of certain qualifying events (as set forth in the form of grant). At December 31, 2007, the total fair value of these 10,000 UARs was $28 thousand, which was based on the following assumptions: (i) remaining life of award of four years; (ii) risk-free interest rate of 3.6%; (iii) an expected distribution yield on Enterprise GP Holdings' units of 4.4%; and (iv) an expected unit price volatility of Enterprise GP Holdings' units of 16.9%.

In November 2006, Mr. Barnett was issued an additional 20,000 UARs and Mr. Ross and Mr. Rampacek were each granted 30,000 UARs under the letter agreement format. The grant date price of these UARs was $34.10 per unit. These awards vest in November 2011 or on the date of certain qualifying events (as set forth in the form of grant). At December 31, 2007, the total fair value of these 80,000 UARs was $272 thousand, which was based on the following assumptions: (i) remaining life of award of four years; (ii) risk-free interest rate of 3.6%; (iii) an expected distribution yield on Enterprise GP Holdings' units of 4.4%; and (iv) an expected unit price volatility of Enterprise GP Holdings' units of 16.9%.

Item 12. *Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters*.

Security Ownership of Certain Beneficial Owners

The following table sets forth certain information as of February 1, 2008, regarding each person known by our general partner to beneficially own more than 5% of our common units.

Title of Class	Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percent of Class
Common units	Dan L. Duncan 1100 Louisiana Street, 10th Floor Houston, Texas 77002	— (1)	—%

(1) For a detailed listing of ownership amounts that comprise Mr. Duncan's total beneficial ownership of our common units, see the table presented in the following section, "Security Ownership of Management," within this Item 12.

Security Ownership of Management

Enterprise Products Partners L.P. and Enterprise GP Holdings L.P.

The following table sets forth certain information regarding the beneficial ownership of our common units and the units of Enterprise GP Holdings L.P. as of February 1, 2008 by:

- our Named Executive Officers;
- the current Directors of EPGP; and
- the current directors and executive officers of EPGP as a group.

If an individual does not own any securities in the foregoing registrants, he is not listed in the following table.

Enterprise GP Holdings owns 100% of the membership interests of EPGP. All information with respect to beneficial ownership has been furnished by the respective directors or officers. Each person has sole voting and dispositive power over the securities shown unless otherwise indicated below. The beneficial ownership amounts of certain individuals include options to acquire our common units that are exercisable within 60 days of the filing date of this annual report.

Mr. Duncan owns 50.4% of the voting stock of EPCO and, accordingly, exercises sole voting and dispositive power with respect to our common units beneficially owned by EPCO and its affiliates. The remaining shares of EPCO capital stock are owned primarily by trusts for the benefit of members of Mr. Duncan's family. The address of EPCO is 1100 Louisiana Street, 10th Floor, Houston, Texas 77002.

	Limited Partner Ownership Interests In			
	Enterprise Products Partners L.P.		Enterprise GP Holdings L.P.	
Name of Beneficial Owner	Amount and Nature Of Beneficial Ownership	Percent of Class	Amount and Nature Of Beneficial Ownership	Percent of Class
Dan L. Duncan:				
Units owned by EPCO:				
Through DFI Delaware Holdings, L.P.	120,086,279	27.6%	—	—
Through Duncan Family Interests, Inc.	—	—	69,203,487	56.2%
Through Enterprise GP Holdings L.P.	13,454,498	3.1%	—	—
Through DFI GP Holdings L.P.	—	—	11,819,722	9.6%
Units owned by DD Securities LLC	487,100	*	3,745,673	3.0%
Units owned by Employee Partnerships (1)	—	—	6,283,479	5.1%
Units owned by family trusts (2)	13,008,241	3.0%	243,071	*
Units owned directly	949,927	*	—	—
Total for Dan L. Duncan	147,986,045	34.0%	91,295,432	74.1%
Richard H. Bachmann (3)	146,014	*	17,469	*
Michael A. Creel (3)	141,328	*	35,000	*
Dr. Ralph S. Cunningham (3)	45,106	*	4,000	*
W. Randall Fowler (3)	77,061	*	3,000	*
James H. Lytal (3)	103,325	*	5,000	*
A.J. Teague (3)	193,941	*	17,000	*
E. William Barnett	2,154	*	—	—
Rex C. Ross	24,285	*	5,400	*
Charles M. Rampacek	615	*	—	—
All current directors and executive officers of EPGP, as a group, (14 individuals in total) (4)	148,775,005	34.2%	91,422,501	74.2%

* *The beneficial ownership of each individual is less than 1% of the registrant's common units outstanding.*

(1) As a result of EPCO's ownership of the general partners of the Employee Partnerships, Mr. Duncan is deemed beneficial owner of the securities held by these entities.

(2) Mr. Duncan is deemed beneficial owner of the securities held by certain family trusts, the beneficiaries of which are shareholders of EPCO.

(3) These individuals are Named Executive Officers.

(4) Cumulatively, this group's beneficial ownership amount includes 150,000 options to acquire common units of Enterprise Products Partners L.P. that were issued under the 1998 Plan. These options are exercisable within 60 days of the filing date of this report.

Essentially all of the ownership interests in us and Enterprise GP Holdings that are owned or controlled by EPCO are pledged as security under the credit facility of an EPCO affiliate. This credit facility contains customary and other events of default relating to EPCO and certain of its affiliates, including Enterprise GP Holdings, TEPPCO and us. In the event of a default under this credit facility, a change in control of Enterprise GP Holdings or us could occur, including a change in control of our respective general partners.

Duncan Energy Partners L.P.

On February 5, 2007, Duncan Energy Partners, a consolidated subsidiary of ours, completed its initial public offering of 14,950,000 common units. Certain of our directors and executive officers purchased common units of Duncan Energy Partners in this offering. The following table presents the beneficial ownership of common units of Duncan Energy Partners by our directors, Named Executive Officers and all directors and officers of our general partner (as a group) at February 1, 2008.

	Duncan Energy Partners	
Name of Beneficial Owner	**Amount And Nature Of Beneficial Ownership**	**Percent of Class**
Dan L. Duncan:		
Through EPO (1)	5,351,571	26.4%
Units owned by family trusts	103,100	*
Total for Dan L. Duncan	5,454,671	26.9%
Richard H. Bachmann (2,3)	10,172	*
Michael A. Creel (3)	7,500	*
Dr. Ralph S. Cunningham (3)	3,000	*
W. Randall Fowler (3,4)	2,000	*
Rex C. Ross	5,000	*
All current directors and executive officers of EPGP, as a group (14 individuals in total)	5,494,943	27.1%

* *The beneficial ownership of each individual is less than 1% of the registrant's units outstanding.*

(1) The number of common units shown for Dan L. Duncan represents the final amount of common units issued to EPO in connection with its contribution of equity interests to Duncan Energy Partners in February 2007.

(2) Mr. Bachmann is the Chief Executive Officer of Duncan Energy Partners.

(3) These individuals are Named Executive Officers.

(4) Mr. Fowler is the Chief Financial Officer of Duncan Energy Partners.

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Securities Authorized for Issuance Under Equity Compensation Plans

The following table sets forth certain information as of December 31, 2007 regarding the 1998 Plan, under which our common units are authorized for issuance to EPCO's key employees and to directors of EPGP through the exercise of unit options.

Plan Category	Number of units to be issued upon exercise of outstanding common unit options	Weighted-average exercise price of outstanding common unit options	Number of units remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)
	(a)	(b)	(c)
Equity compensation plans approved by unitholders:			
1998 Plan	2,315,000	$26.18	1,282,256
Equity compensation plans not approved by unitholders:			
None.	—	—	—
Total for equity compensation plans	2,315,000	$26.18	1,232,256

(1) Of the 2,315,000 unit options outstanding at December 31, 2007, 335,000 were immediately exercisable and an additional 285,000, 380,000, 510,000 and 805,000 options are exercisable in 2008, 2009, 2010 and 2011, respectively.

1998 Plan

The 1998 Plan is effective until either all available common units under the plan have been issued to participants or the earlier termination of the 1998 Plan by EPCO. The 1998 Plan also provides for the issuance of restricted common units, of which 1,688,540 were outstanding at December 31, 2007. During 2007, a total of 738,040 restricted unit awards were issued to key employees of EPCO and our independent directors. For additional information regarding the 1998 Plan, see Note 5 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Enterprise Products 2008 Long-Term Incentive Plan

On January 29, 2008, the unitholders of Enterprise Products Partners approved the Enterprise Products 2008 Long-Term Incentive Plan (the "Incentive Plan"), which provides for awards of the Partnership's common units and other rights to the Partnership's non-employee directors and to consultants and employees of EPCO and its affiliates providing services to the Partnership. Awards under the Incentive Plan may be granted in the form of restricted units, phantom units, unit options, unit appreciation rights and distribution equivalent rights. The Incentive Plan will be administered by EPGP's ACG Committee. Up to 10,000,000 of the Partnership's common units may be granted as awards under the Incentive Plan, with such amount subject to adjustment as provided for under the terms of the plan.

The exercise price of unit options or UARs awarded to participants will be determined by the ACG Committee (at its discretion) at the date of grant and may be no less than the fair market value of the option award as of the date of grant. The Incentive Plan may be amended or terminated at any time by the Board of Directors of EPCO or EPGP's ACG Committee; however, any material amendment, such as a significant increase in the number of units available under the plan or a change in the types of awards available under the plan, would require the approval of the unitholders of the Partnership. The ACG Committee is also authorized to make adjustments in the terms and conditions of, and the criteria included in awards under the plan in specified circumstances. The Incentive Plan is effective until January 29, 2018 or, if earlier, the time which all available units under the Incentive Plan have been delivered to participants or the time of termination of the plan by EPCO or EPGP's ACG Committee.

Item 13. *Certain Relationships and Related Transactions, and Director Independence*.

Certain Relationships and Related Transactions

The following information summarizes our business relationships and transactions with related parties during the year ended December 31, 2007. We believe that the terms and provisions of our related party agreements are fair to us; however, such agreements and transactions may not be as favorable to us as we could have obtained from unaffiliated third parties. For additional information regarding our related party transactions, see Note 17 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Relationship with EPCO and affiliates

We have an extensive and ongoing relationship with EPCO and its affiliates, which include the following significant entities that are not a part of our consolidated group of companies:

- EPCO and its private company subsidiaries;
- EPGP, our sole general partner;
- Enterprise GP Holdings, which owns and controls our general partner;
- the Employee Partnerships;
- TEPPCO, which is owned and controlled by Enterprise GP Holdings; and
- Energy Transfer Equity, an equity method investment of Enterprise GP Holdings.

We also have an ongoing relationship with Duncan Energy Partners, the financial statements of which are consolidated with those of our own. Our transactions with Duncan Energy Partners are eliminated in consolidation.

EPCO is a private company controlled by Dan L. Duncan, who is also a Director and Chairman of EPGP, our general partner. At December 31, 2007, EPCO and its affiliates beneficially owned 147,986,045 (or 34.0%) of our outstanding common units, which includes 13,454,498 of our common units owned by Enterprise GP Holdings. In addition, at December 31, 2007, EPCO and its affiliates beneficially owned 77.1% of the limited partner interests of Enterprise GP Holdings and 100% of its general partner, EPE Holdings. Enterprise GP Holdings owns all of the membership interests of EPGP. The principal business activity of EPGP is to act as our managing partner. The executive officers and certain of the directors of EPGP and EPE Holdings are employees of EPCO.

As our general partner, EPGP received cash distributions of $124.4 million from us during the year ended December 31, 2007. This amount includes incentive distributions of $107.4 million.

We and EPGP are both separate legal entities apart from each other and apart from EPCO, Enterprise GP Holdings and their respective other affiliates, with assets and liabilities that are separate from those of EPCO, Enterprise GP Holdings and their respective other affiliates. EPCO and its private company subsidiaries and affiliates depend on the cash distributions they receive from us, Enterprise GP Holdings and other investments to fund their other operations and to meet their debt obligations. EPCO and its private company affiliates received $355.5 million in cash distributions from us and Enterprise GP Holdings during the year ended December 31, 2007.

The ownership interests in us that are owned or controlled by Enterprise GP Holdings are pledged as security under its credit facility. In addition, substantially all of the ownership interests in us that are owned or controlled by EPCO and its affiliates, other than those interests owned by Enterprise GP Holdings, Dan Duncan LLC and certain trusts affiliated with Dan L. Duncan, are pledged as security under the credit facility of a private company affiliate of EPCO. This credit facility contains customary and other events of default relating to EPCO and certain affiliates, including Enterprise GP Holdings, TEPPCO and us.

An affiliate of EPCO provides us trucking services for the transportation of NGLs and other products. For the year ended December 31, 2007, we paid this trucking affiliate $17.5 million for such services.

We lease office space in various buildings from affiliates of EPCO. The rental rates in these lease agreements approximate market rates. For the year ended December 31, 2007, we paid EPCO $5.6 million for office space leases.

EPCO Administrative Services Agreement. We have no employees. All of our operating functions and general and administrative support services are provided by employees of EPCO pursuant to an administrative services agreement (the "ASA"). We, Duncan Energy Partners, Enterprise GP Holdings, TEPPCO and our respective general partners are parties to the ASA. The significant terms of the ASA are as follows:

- EPCO will provide selling, general and administrative services, and management and operating services, as may be necessary to manage and operate our businesses, properties and assets (all in accordance with prudent industry practices). EPCO will employ or otherwise retain the services of such personnel as may be necessary to provide such services.
- We are required to reimburse EPCO for its services in an amount equal to the sum of all costs and expenses incurred by EPCO which are directly or indirectly related to our business or activities (including expenses reasonably allocated to us by EPCO). In addition, we have agreed to pay all sales, use, excise, value added or similar taxes, if any, that may be applicable from time to time in respect of the services provided to us by EPCO.
- EPCO will allow us to participate as named insureds in its overall insurance program, with the associated premiums and other costs being allocated to us.

Under the ASA, EPCO subleases to us (for $1 per year) certain equipment which it holds pursuant to operating leases and has assigned to us its purchase option under such leases (the "retained leases"). EPCO remains liable for the actual cash lease payments associated with these agreements. We record the full value of these payments made by EPCO on our behalf as a non-cash related party operating lease expense, with the offset to partners' equity accounted for as a general contribution to our partnership. At December 31, 2007, the retained leases were for a cogeneration unit and approximately 100 railcars. Should we decide to exercise the purchase options associated with the retained leases, $2.3 million would be payable in 2008 and $3.1 million in 2016.

Our operating costs and expenses for the year ended December 31, 2007 include reimbursement payments to EPCO for the costs it incurs to operate our facilities, including compensation of employees. We reimburse EPCO for actual direct and indirect expenses it incurs related to the operation of our assets. Such reimbursements were $273.0 million during the year ended December 31, 2007.

Likewise, our general and administrative costs for the year ended December 31, 2007 includes amounts we reimburse to EPCO for administrative services, including compensation of employees. In general, our reimbursement to EPCO for administrative services is either (i) on an actual basis for direct expenses it may incur on our behalf (e.g., the purchase of office supplies) or (ii) based on an allocation of such charges between the various parties to ASA based on the estimated use of such services by each party (e.g., the allocation of general legal or accounting salaries based on estimates of time spent on each entity's business and affairs). Such reimbursements were $56.5 million during the year ended December 31, 2007.

The ASA also addresses potential conflicts that may arise among Enterprise Products Partners (including EPGP), Enterprise GP Holdings (including EPE Holdings), Duncan Energy Partners (including DEP GP), and the EPCO Group. The EPCO Group includes EPCO and its other affiliates, but excludes Enterprise Products Partners, Enterprise GP Holdings, Duncan Energy Partners and their respective general partners. With respect to potential conflicts, the ASA provides, among other things, that:

- If a business opportunity to acquire "equity securities" (as defined below) is presented to the EPCO Group, Enterprise Products Partners (including EPGP), Enterprise GP Holdings (including EPE Holdings), Duncan Energy Partners (including DEP GP), then Enterprise GP Holdings will have the first right to pursue such opportunity. The term "equity securities" is defined to include:

  - general partner interests (or securities which have characteristics similar to general partner interests) or interests in "persons" that own or control such general partner or similar interests (collectively, "GP Interests") and securities convertible, exercisable, exchangeable or otherwise representing ownership or control of such GP Interests; and

  - incentive distribution rights and limited partner interests (or securities which have characteristics similar to incentive distribution rights or limited partner interests) in publicly traded partnerships or interests in "persons" that own or control such limited partner or similar interests (collectively, "non-GP Interests"); provided that such non-GP Interests are associated with GP Interests and are owned by the owners of GP Interests or their respective affiliates.

  Enterprise GP Holdings will be presumed to want to acquire the equity securities until such time as EPE Holdings advises the EPCO Group, EPGP and DEP GP that it has abandoned the pursuit of such business opportunity. In the event that the purchase price of the equity securities is reasonably likely to equal or exceed $100 million, the decision to decline the acquisition will be made by the Chief Executive Officer of EPE Holdings after consultation with and subject to the approval of the ACG Committee of EPE Holdings. If the purchase price is reasonably likely to be less than $100 million, the Chief Executive Officer of EPE Holdings may make the determination to decline the acquisition without consulting the ACG Committee of EPE Holdings.

  In the event that Enterprise GP Holdings abandons the acquisition and so notifies the EPCO Group, EPGP and DEP GP, Enterprise Products Partners will have the second right to pursue such acquisition. Enterprise Products Partners will be presumed to want to acquire the equity securities until such time as EPGP advises the EPCO Group and DEP GP that Enterprise Products Partners has abandoned the pursuit of such acquisition. In determining whether or not to pursue the acquisition, Enterprise Products Partners will follow the same procedures applicable to Enterprise GP Holdings, as described above but utilizing EPGP’s Chief Executive Officer and ACG Committee.

  In its sole discretion, Enterprise Products Partners may affirmatively direct such acquisition opportunity to Duncan Energy Partners. In the event this occurs, Duncan Energy Partners may pursue such acquisition.

  In the event Enterprise Products Partners abandons the acquisition opportunity for the equity securities and so notifies the EPCO Group and DEP GP, the EPCO Group may pursue the acquisition or offer the opportunity to TEPPCO (including TEPPCO GP) and their controlled affiliates, in either case, without any further obligation to any other party or offer such opportunity to other affiliates.

- If any business opportunity not covered by the preceding bullet point (i.e. not involving "equity securities") is presented to the EPCO Group, Enterprise Products Partners (including EPGP), Enterprise GP Holdings (including EPE Holdings), or Duncan Energy Partners (including DEP GP), Enterprise Products Partners will have the first right to pursue such opportunity either for itself or, if desired by Enterprise Products Partners in its sole discretion, for the benefit of Duncan

Energy Partners. It will be presumed that Enterprise Products Partners will pursue the business opportunity until such time as its general partner advises the EPCO Group, EPE Holdings and DEP GP that it has abandoned the pursuit of such business opportunity.

In the event the purchase price or cost associated with the business opportunity is reasonably likely to equal or exceed $100 million, any decision to decline the business opportunity will be made by the Chief Executive Officer of EPGP after consultation with and subject to the approval of the ACG Committee of EPGP. If the purchase price or cost is reasonably likely to be less than $100 million, the Chief Executive Officer of EPGP may make the determination to decline the business opportunity without consulting EPGP's ACG Committee.

In its sole discretion, Enterprise Products Partners may affirmatively direct such acquisition opportunity to Duncan Energy Partners. In the event this occurs, Duncan Energy Partners may pursue such acquisition.

In the event that Enterprise Products Partners abandons the business opportunity for itself and Duncan Energy Partners and so notifies the EPCO Group, EPE Holdings and DEP GP, Enterprise GP Holdings will have the second right to pursue such business opportunity. It will be presumed that Enterprise GP Holdings will pursue such acquisition until such time as its general partner declines such opportunity (in accordance with the procedures described above for Enterprise Products Partners) and advises the EPCO Group that it has abandoned the pursuit of such business opportunity. Should this occur, the EPCO Group may either pursue the business opportunity or offer the business opportunity to TEPPCO (including TEPPCO GP) and their controlled affiliates without any further obligation to any other party or offer such opportunity to other affiliates.

None of Enterprise Products Partners, Enterprise GP Holdings, Duncan Energy Partners or their respective general partners or the EPCO Group have any obligation to present business opportunities to TEPPCO (including TEPPCO GP) or their controlled affiliates. Likewise, TEPPCO (including TEPPCO GP) and their controlled affiliates have no obligation to present business opportunities to Enterprise Products Partners, Enterprise GP Holdings, Duncan Energy Partners or their respective general partners or the EPCO Group.

Employee Partnerships. EPCO formed the Employee Partnerships to serve as an incentive arrangement for key employees of EPCO by providing them a "profits interest" in such partnerships. Certain EPCO employees who work on behalf of us and EPCO were issued Class B limited partner interests and admitted as Class B limited partners without any capital contribution. The profits interest awards (i.e., the Class B limited partner interests) in the Employee Partnerships entitles each holder to participate in the appreciation in value of the Parent Company's Units. For information regarding the Employee Partnerships, see Note 5 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Relationship with TEPPCO

TEPPCO became a related party to us in February 2005 in connection with the acquisition of TEPPCO GP by a private company subsidiary of EPCO. In May 2007, Enterprise GP Holdings purchased TEPPCO GP from this private company subsidiary of EPCO.

We received $67.6 million from TEPPCO during the year ended December 31, 2007 from the sale of hydrocarbon products. We paid TEPPCO $19.4 million for NGL pipeline transportation and storage services during the year ended December 31, 2007.

In August 2006, we became a joint venture partner with TEPPCO in its Jonah Gas Gathering Company ("Jonah"), which owns the Jonah Gas Gathering System located in the Greater Green River Basin of southwestern Wyoming. The Jonah Gathering System gathers and transports natural gas produced from the Jonah and Pinedale fields to regional natural gas processing plants and major interstate pipelines that deliver natural gas to end-user markets.

Prior to entering into the Jonah joint venture, we managed the construction of the Phase V expansion and funded the initial construction costs under a letter of intent we entered into in February 2006. In connection with the joint venture arrangement, we and TEPPCO plan to continue the Phase V expansion, which is expected to increase the capacity of the Jonah Gathering System from 1.5 Bcf/d to 2.4 Bcf/d and to significantly reduce system operating pressures, which we anticipate will lead to increased production rates and ultimate reserve recoveries. The first portion of the expansion, which has increased the system gathering capacity to 2.0 Bcf/d, was completed in July 2007 and the final phase of this expansion is expected to be completed by April 2008. The total anticipated cost of the Phase V expansion is expected to be approximately $505.0 million. We continue to manage the Phase V construction project.

Since August 1, 2006, we and TEPPCO have equally shared in the construction costs of the Phase V expansion. TEPPCO has reimbursed us $261.6 million, which represents 50% of total Phase V costs incurred through December 31, 2007. We had a receivable of $9.9 million from TEPPCO at December 31, 2007 for Phase V expansion costs.

TEPPCO was entitled to all distributions from the joint venture until specified milestones were achieved, at which point, we became entitled to receive 50% of the incremental cash flow from portions of the system placed in service as part of the expansion. Since the first phase of this expansion was reached in July 2007, we and TEPPCO have shared earnings based on a formula that takes into account our respective capital contributions, including expenditures by TEPPCO prior to the expansion.

At December 31, 2007, we owned an approximate 19.4% interest in Jonah and TEPPCO owns 80.6%. We operate the Jonah system. We account for our investment in the Jonah joint venture using the equity method.

The Jonah joint venture is governed by a management committee comprised of two representatives approved by us and two appointed by TEPPCO, each with equal voting power. After an in-depth consideration of all relevant factors, this transaction was approved by the ACG Committee of our general partner and the Audit and Conflicts Committee of the general partner of TEPPCO. The ACG Committee of our general partner received a fairness opinion in connection with this transaction. The transaction was reviewed and recommended for approval by the Audit and Conflicts Committee of TEPPCO GP with assistance from an independent financial advisor.

We have agreed to indemnify TEPPCO from any and all losses, claims, demands, suits, liabilities, costs and expenses arising out of or related to breaches of our representations, warranties, or covenants related to the Jonah joint venture. A claim for indemnification cannot be filed until the losses suffered by TEPPCO exceed $1.0 million. The maximum potential amount of future payments under the indemnity agreement is limited to $100.0 million. All indemnity payments are net of insurance recoveries that TEPPCO may receive from third-party insurance carriers. We carry insurance coverage that may offset any payments required under the indemnification.

In January 2007, we purchased a 10-mile segment of pipeline from TEPPCO located in the Houston area for $8.0 million. This pipeline segment is part of the DEP South Texas NGL Pipeline System that commenced operations in January 2007. In addition, we entered into a lease with TEPPCO for an 11-mile interconnecting pipeline located in the Houston area that is part of the DEP South Texas NGL Pipeline System. Although the primary term of the lease expired in September 2007, it is being renewed on a month-to-month basis until construction of a parallel pipeline is completed in early 2008. These transactions were in accordance with the Board-approved management authorization policy.

Relationship with Energy Transfer Equity

Enterprise GP Holdings acquired equity method investments in Energy Transfer Equity and its general partner in May 2007. As a result, Energy Transfer Equity and its consolidated subsidiaries became related parties to our consolidated businesses.

For the eight months ended December 31, 2007, we recorded $294.4 million of revenues from Energy Transfer Partners, L.P. ("ETP"), primarily from NGL marketing activities. We incurred $35.2 million in operating costs and expenses for the eight months ended December 31, 2007. We have a long-term revenue generating contract with Titan Energy Partners, L.P. ("Titan"), a consolidated subsidiary of ETP. Titan purchases substantially all of its propane requirements from us. The contract continues until March 31, 2010 and contains renewal and extension options. We and Energy Transfer Company ("ETC OLP") transport natural gas on each other's systems and share operating expenses on certain pipelines. ETC OLP also sells natural gas to us.

Relationships with Unconsolidated Affiliates

Many of our unconsolidated affiliates perform supporting or complementary roles to our other business operations. Since we and our affiliates hold ownership interests in these entities and directly or indirectly benefit from our related party transactions with such entities, they are presented here. The following information summarizes significant related party transactions with our current unconsolidated affiliates:

- We sell natural gas to Evangeline, which, in turn, uses the natural gas to satisfy supply commitments it has with a major Louisiana utility. Revenues from Evangeline were $268.0 million for the year ended December 31, 2007. In addition, we furnished $1.1 million in letters of credit on behalf of Evangeline at December 31, 2007.

- We pay Promix for the transportation, storage and fractionation of NGLs. In addition, we sell natural gas to Promix for its plant fuel requirements. For the year ended December 31, 2007, we recorded revenues of $17.3 million from Promix and paid Promix $30.4 million for its services to us.

- We perform management services for certain of our unconsolidated affiliates. We charged such affiliates $9.3 million for such services during the year ended December 31, 2007.

Relationship with Duncan Energy Partners

In September 2006, we formed a consolidated subsidiary, Duncan Energy Partners, to acquire, own and operate a diversified portfolio of midstream energy assets and to support the growth objectives of EPO. On February 5, 2007, this subsidiary completed its initial public offering of 14,950,000 common units at $21.00 per unit, which generated net proceeds to Duncan Energy Partners of $291.9 million. As consideration for assets contributed and reimbursement for capital expenditures related to these assets, Duncan Energy Partners distributed $260.6 million of these net proceeds to Enterprise Products Partners (along with $198.9 million in borrowings under its credit facility and a final amount of 5,351,571 common units of Duncan Energy Partners). Duncan Energy Partners used $38.5 million of net proceeds from the overallotment to redeem 1,950,000 of the 7,301,571 common units it had originally issued to Enterprise Products Partners, resulting in the final amount of 5,351,571 common units beneficially owned by Enterprise Products Partners. We used the cash received from Duncan Energy Partners to temporarily reduce amounts outstanding under EPO's Multi-Year Revolving Credit Facility.

In addition to the 34% direct ownership interest we retained in certain subsidiaries of Duncan Energy Partners, we also own the 2% general partner interest in Duncan Energy Partners and 26.4% of Duncan Energy Partners' outstanding common units. EPO directs the business operations of Duncan Energy Partners through its control of Duncan Holdings, LLC ("DEP GP"). Certain of our officers and directors are also beneficial owners of common units of Duncan Energy Partners (see Item 12).

For financial reporting purposes, we consolidate the financial statements of Duncan Energy Partners with those of our own and reflect its operations in our business segments. All intercompany transactions between us and Duncan Energy Partners are eliminated in the preparation of our consolidated financial statements. Also, due to common control of the entities by Dan L. Duncan, the initial consolidated balance sheet of Duncan Energy Partners reflects our historical carrying basis in each of the subsidiaries contributed to Duncan Energy Partners. Public ownership of Duncan Energy Partners' net assets and earnings are presented as a component of minority interest in our consolidated financial statements.

The borrowings of Duncan Energy Partners are presented as part of our consolidated debt; however, we do not have any obligation for the payment of interest or repayment of borrowings incurred by Duncan Energy Partners.

We have significant involvement with all of the subsidiaries of Duncan Energy Partners, including the following types of transactions: (i) we utilize storage services provided by Mont Belvieu Caverns to support our Mont Belvieu fractionation and other businesses; (ii) we buy natural gas from and sell natural gas to Acadian Gas in connection with our normal business activities; and (iii) we are the sole shipper on the DEP South Texas NGL Pipeline System.

We may contribute other equity interests in our subsidiaries to Duncan Energy Partners in the near term and use the proceeds we receive from Duncan Energy Partners to fund our capital spending program.

For additional information regarding Duncan Energy Partners, see "Other Items — Initial Public Offering of Duncan Energy Partners" under Item 7 of this annual report.

Omnibus Agreement. On February 5, 2007, EPO and Duncan Energy Partners entered into an Omnibus Agreement that governs our relationship with Duncan Energy Partners on the following matters:

- indemnification for certain environmental liabilities, tax liabilities and right-of-way defects;
- reimbursement of certain expenditures incurred by DEP South Texas NGL and Mont Belvieu Caverns;
- a right of first refusal to EPO in Duncan Energy Partners' current and future subsidiaries and a right of first refusal on the material assets of these entities, other than sales of inventory and other assets in the ordinary course of business; and
- a preemptive right with respect to equity securities issued by certain of Duncan Energy Partners' subsidiaries, other than as consideration in an acquisition or in connection with a loan or debt financing.

EPO has indemnified Duncan Energy Partners against certain pre-February 2007 environmental and related liabilities associated with the assets EPO contributed to Duncan Energy Partners at the time of its initial public offering. These liabilities include both known and unknown environmental and related liabilities. This indemnification obligation will terminate on February 5, 2010. There is an aggregate cap of $15.0 million on the amount of indemnity coverage. In addition, Duncan Energy Partners is not entitled to indemnification until the aggregate amount of claims it incurs exceeds $250 thousand. Liabilities resulting from a change of law after February 5, 2007 are excluded from the EPO environmental indemnity. In addition, EPO has indemnified Duncan Energy Partners for liabilities related to:

- certain defects in the easement rights or fee ownership interests in and to the lands on which any assets contributed to Duncan Energy Partners in connection with its initial public offering are located and failure to obtain certain consents and permits necessary to conduct its business that arise through February 5, 2010; and
- certain income tax liabilities attributable to the operation of the assets contributed to Duncan Energy Partners in connection with its initial public offering prior to February 5, 2007.

The Omnibus Agreement may not be amended without the prior approval of the ACG Committee if the proposed amendment will, in the reasonable discretion of DEP GP, adversely affect holders of the it's common units.

Neither we, nor EPO and any of its affiliates are restricted under the Omnibus Agreement from competing with Duncan Energy Partners. Except as otherwise expressly agreed in the EPCO administrative services agreement, EPO and any of its affiliates may acquire, construct or dispose of additional midstream energy or other assets in the future without any obligation to offer Duncan Energy Partners the opportunity to purchase or construct those assets. These agreements are in addition to other agreements relating to business opportunities and potential conflicts of interest set forth in the administrative services agreement with EPO, EPCO and other affiliates of EPCO.

Under the Omnibus Agreement, EPO agreed to make additional contributions to Duncan Energy Partners as reimbursement for its 66% share of any excess construction costs above (i) the $28.6 million of estimated capital expenditures to complete the Phase II expansions of the DEP South Texas NGL Pipeline System and (ii) $14.1 million of estimated construction costs for additional brine production capacity and above-ground storage reservoir projects at Mont Belvieu, Texas. Both projects were underway at the time of Duncan Energy Partners' initial public offering. In December 2007, EPO made contributions totaling $9.9 million to Duncan Energy Partners' subsidiaries in connection with this provision of the Omnibus Agreement.

Review and Approval of Transactions with Related Parties

Our partnership agreement and ACG Committee charter set forth policies and procedures for the review and approval of certain transactions with persons affiliated with or related to us. As further described below, our partnership agreement and ACG Committee charter set forth procedures by which related party transactions and conflicts of interest may be approved or resolved by our general partner or the ACG Committee. Under our partnership agreement, whenever a potential conflict of interest exists or arises between our general partner or any of its affiliates, on the one hand, and us, any of our subsidiaries or any partner, on the other hand, any resolution or course of action by our general partner or its affiliates in respect of such conflict of interest is permitted and deemed approved by all of our partners, and will not constitute a breach of our partnership agreement or any agreement contemplated by such agreement, or of any duty stated or implied by law or equity, if the resolution or course of action is or, by operation of the partnership agreement is deemed to be, fair and reasonable to us; provided that, any conflict of interest and any resolution of such conflict of interest will be conclusively deemed fair and reasonable to us if such conflict of interest or resolution is (i) approved by a majority of the members of our ACG Committee ("Special Approval"), or (ii) on terms objectively demonstrable to be no less favorable to us than those generally being provided to or available from unrelated third parties.

The ACG Committee (in connection with Special Approval) is authorized in connection with its resolution of any conflict of interest to consider:

- the relative interests of any party to such conflict, agreement, transaction or situation and the benefits and burdens relating to such interest;
- the totality of the relationships between the parties involved (including other transactions that may be particularly favorable or advantageous to the Partnership);
- any customary or accepted industry practices and any customary or historical dealings with a particular person;
- any applicable generally accepted accounting or engineering practices or principles;
- the relative cost of capital of the parties and the consequent rates of return to the equity holders of the parties; and
- such additional factors as the committee determines in its sole discretion to be relevant, reasonable or appropriate under the circumstances.

The review and approval process of the ACG Committee, including factual matters that may be considered in determining whether a transaction is fair and reasonable, is generally governed by Section 7.9 of our partnership agreement. As discussed above, the ACG Committee's Special Approval is conclusively deemed fair and reasonable to us under the partnership agreement.

Related party transactions that do not occur under the ASA and that are not reviewed by the ACG Committee, as described above, may be subject to our general partner's Board-approved written internal review and approval policies and procedures. These internal policies and procedures, which apply to related party transactions as well as transactions with unrelated parties, specify thresholds for our general partner's officers and managers to authorize various categories of transactions, including purchases and sales of assets, expenditures, commercial and financial transactions and legal agreements. The specified thresholds for some categories of transactions are less than $120,000 and for others are substantially greater.

In submitting a matter to the ACG Committee, the Board or the general partner may charge the committee with reviewing the transaction and providing the Board a recommendation, or it may delegate to the committee the power to approve the matter. When so engaged, the ACG Committee Charter provides that, unless the ACG Committee determines otherwise, the committee shall perform the following functions:

- Review a summary of the proposed transaction(s) that outlines (i) its terms and conditions (explicit and implicit), (ii) a brief history of the transaction, and (iii) the impact that the transaction will have on our unitholders and personnel, including earnings per unit and distributable cash flow.
- Review due diligence findings by management and make additional due diligence requests, if deemed necessary.
- Engage third-party independent advisors, where necessary, to provide committee members with comparable market values, legal advice and similar services directly related to the proposed transaction.
- Conduct interviews regarding the proposed transaction with the most knowledgeable company officials to ensure that the committee members have all relevant facts before rendering their judgment.

On November 6, 2007, the ACG Committee charter was amended and restated. The amended and restated charter provides, among other things, that the ACG Committee will review and approve related-party transactions (i) for which Board approval is required by the partnership's management authorization policy (generally, for transactions involving amounts greater than $100 million), (ii) where an officer or director of our general partner or of any partnership subsidiary is a party, (iii) when requested to do so by management of the partnership or the Board, or (iv) pursuant to the limited partnership agreement of the partnership or the limited liability company agreement of our general partner.

In the normal course of business, our management routinely reviews all other related party transactions, including proposed asset purchases and business combinations and purchases and sales of product. As a matter of course, management reviews the terms and conditions of the proposed transactions, performs appropriate levels of due diligence and assesses the impact of the transaction on our partnership. In addition, the ACG Committee reviews a summary of all related party transactions with management on a quarterly basis where the amounts involved exceed $1.0 million and the underlying prices are not market-based. In connection with such review, the ACG Committee received no indication that such transactions were not fair and reasonable to the Company or that management of the Company improperly exercised its authority under our general partner's written internal review and approval policies and procedures.

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The ACG Committee does not separately review individual transactions covered by our administrative services agreement with EPCO, which agreement and related allocation methods have been previously reviewed and approved by the ACG Committee and/or the Board. The administrative services agreement governs numerous day-to-day transactions between us and our subsidiaries and EPCO and its affiliates, including the provision by EPCO of administrative and other services to us and our subsidiaries and our reimbursement of costs for those services.

During the year ended December 31, 2006, the ACG Committee reviewed and approved the purchase of the Pioneer plant from TEPPCO and Jonah Joint Venture with TEPPCO referenced elsewhere in this Item 13. All other transactions with related parties were either governed by the administrative services agreement or effected under our general partner's written internal review and approval policies and procedures.

Director Independence

Messrs. Barnett, Ross and Rampacek have been determined to be independent under the applicable NYSE listing standards and are independent under the rules of the SEC applicable to audit committees. For a discussion of independence standards applicable to the Board and factors considered by the Board in making its independence determinations, please refer to "Corporate Governance" and "ACG Committee" under Item 10 of this annual report.

Item 14. *Principal Accountant Fees and Services*.

We have engaged Deloitte & Touche LLP, the member firms of Deloitte Touche Tohmatsu, and their respective affiliates (collectively, "Deloitte & Touche") as our independent auditor. The following table summarizes fees we paid Deloitte & Touche for independent auditing, tax and related services for each of the last two fiscal years (dollars in thousands):

	For Year Ended December 31,	
	2007	2006
Audit Fees (1)	$3,825	$4,476
Audit-Related Fees (2)	79	13
Tax Fees (3)	341	297
All Other Fees (4)	n/a	n/a

(1) Audit fees represent amounts billed for each of the years presented for professional services rendered in connection with (i) the audit of our annual financial statements and internal controls over financial reporting, (ii) the review of our quarterly financial statements or (iii) those services normally provided in connection with statutory and regulatory filings or engagements including comfort letters, consents and other services related to SEC matters. This information is presented as of the latest practicable date for this annual report.

(2) Audit-related fees represent amounts we were billed in each of the years presented for assurance and related services that are reasonably related to the performance of the annual audit or quarterly reviews. This category primarily includes services relating to internal control assessments and accounting-related consulting.

(3) Tax fees represent amounts we were billed in each of the years presented for professional services rendered in connection with tax compliance, tax advice, and tax planning. This category primarily includes services relating to the preparation of unitholder annual K-1 statements and partnership tax planning.

(4) All other fees represent amounts we were billed in each of the years presented for services not classifiable under the other categories listed in the table above. No such services were rendered by Deloitte & Touche during the last two years.

The ACG Committee of our general partner has approved the use of Deloitte & Touche as our independent principal accountant. In connection with its oversight responsibilities, the ACG Committee has adopted a pre-approval policy regarding any services proposed to be performed by Deloitte & Touche. The pre-approval policy includes four primary service categories: Audit, Audit-related, Tax and Other.

In general, as services are required, management and Deloitte & Touche submit a detailed proposal to the ACG Committee discussing the reasons for the request, the scope of work to be performed, and an estimate of the fee to be charged by Deloitte & Touche for such work. The ACG Committee discusses the request with management and Deloitte & Touche, and if the work is deemed necessary and appropriate for Deloitte & Touche to perform, approves the request subject to the fee amount presented (the initial "pre-approved" fee amount). As part of these discussions, the ACG Committee must determine whether or not the proposed services are permitted under the rules and regulations concerning auditor independence under the Sarbanes-Oxley Act of 2002 as well as rules of the American Institute of Certified Public Accountants. If at a later date, it appears that the initial pre-approved fee amount may be insufficient to complete the work, then management and Deloitte & Touche must present a request to the ACG Committee to increase the approved amount and the reasons for the increase.

Under the pre-approval policy, management cannot act upon its own to authorize an expenditure for services outside of the pre-approved amounts. On a quarterly basis, the ACG Committee is provided a schedule showing Deloitte & Touche's pre-approved amounts compared to actual fees billed for each of the primary service categories. The ACG Committee's pre-approval process helps to ensure the independence of our principal accountant from management.

In order for Deloitte & Touche to maintain its independence, we are prohibited from using them to perform general bookkeeping, management or human resource functions, and any other service not permitted by the Public Company Accounting Oversight Board. The ACG Committee's pre-approval policy also precludes Deloitte & Touche from performing any of these services for us.

PART IV

Item 15. ***Exhibits and Financial Statement Schedules.***

(a)(1) Financial Statements

Our consolidated financial statements are included under Part II, Item 8 of this annual report. For a listing of these statements and accompanying footnotes, see "Index to Financial Statements" under Item 8 of this annual report.

(a)(2) Financial Statement Schedules

All schedules, have been omitted because they are either not applicable, not required or the information called for therein appears in the consolidated financial statements or notes thereto.

(a)(3) Exhibits

2.1 Merger Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products Management LLC, GulfTerra Energy Partners, L.P. and GulfTerra Energy Company, L.L.C. (incorporated by reference to Exhibit 2.1 to Form 8-K filed December 15, 2003).

2.2 Amendment No. 1 to Merger Agreement, dated as of August 31, 2004, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products Management LLC, GulfTerra Energy Partners, L.P. and GulfTerra Energy Company, L.L.C. (incorporated by reference to Exhibit 2.1 to Form 8-K filed September 7, 2004).

2.3 Parent Company Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products GTM, LLC, El Paso Corporation, Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso EPN Investments, L.L.C. and GulfTerra GP Holding Company (incorporated by reference to Exhibit 2.2 to Form 8-K filed December 15, 2003).

2.4 Amendment No. 1 to Parent Company Agreement, dated as of April 19, 2004, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products GTM, LLC, El Paso Corporation, Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso EPN Investments, L.L.C. and GulfTerra GP Holding Company (incorporated by reference to Exhibit 2.1 to the Form 8-K filed April 21, 2004).

2.5	Purchase and Sale Agreement (Gas Plants), dated as of December 15, 2003, by and between El Paso Corporation, El Paso Field Services Management, Inc., El Paso Transmission, L.L.C., El Paso Field Services Holding Company and Enterprise Products Operating L.P. (incorporated by reference to Exhibit 2.4 to Form 8-K filed December 15, 2003).
3.1	Certificate of Limited Partnership of Enterprise Products Partners L.P. (incorporated by reference to Exhibit 3.6 to Form 10-Q filed November 8, 2007).
3.2	Fifth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P., dated effective as of August 8, 2005 (incorporated by reference to Exhibit 3.1 to Form 8-K filed August 10, 2005).
3.3	First Amendment to Fifth Amended and Restated Partnership Agreement of Enterprise Products Partners L.P. dated as of December 27, 2007 (incorporated by reference to Exhibit 3.1 to Form 8-K/A filed January 3, 2008).
3.4	Fifth Amended and Restated Limited Liability Company Agreement of Enterprise Products GP, LLC, dated as of November 7, 2007 (incorporated by reference to Exhibit 3.2 to Form 10-Q filed November 8, 2007).
3.5	Limited Liability Company Agreement of Enterprise Products Operating LLC dated as of June 30, 2007 (incorporated by reference to Exhibit 3.3 to Form 10-Q filed on August 8, 2007).
3.6	Certificate of Incorporation of Enterprise Products OLPGP, Inc., dated December 3, 2003 (incorporated by reference to Exhibit 3.5 to Form S-4 Registration Statement, Reg. No. 333-121665, filed December 27, 2004).
3.7	Bylaws of Enterprise Products OLPGP, Inc., dated December 8, 2003 (incorporated by reference to Exhibit 3.6 to Form S-4 Registration Statement, Reg. No. 333-121665, filed December 27, 2004).
3.8	Certificate of Limited Partnership of Duncan Energy Partners L.P. (incorporated by reference to Exhibit 3.1 to Duncan Energy Partners L.P. Form S-1 Registration Statement, Reg. No. 333-138371, filed November 2, 2006).
3.9	Amended and Restated Agreement of Limited Partnership of Duncan Energy Partners L.P., dated February 5, 2007 (incorporated by reference to Exhibit 3.1 to Duncan Energy Partners L.P.'s Form 8-K/A filed February 5, 2007).
3.10	First Amendment to Amended and Restated Partnership Agreement of Duncan Energy Partners L.P. dated as of December 27, 2007 (incorporated by reference to Exhibit 3.1 to Duncan Energy Partners L.P.'s Form 8-K filed on January 3, 2008).
4.1	Form of Common Unit certificate (incorporated by reference to Exhibit 4.1 to Registration Statement on Form S-1/A; File No. 333-52537, filed July 21, 1998).
4.2	Indenture dated as of March 15, 2000, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and First Union National Bank, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed March 10, 2000).
4.3	First Supplemental Indenture dated as of January 22, 2003, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Registration Statement on Form S-4, Reg. No. 333-102776, filed January 28, 2003).
4.4	Second Supplemental Indenture dated as of February 14, 2003, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 10-K filed March 31, 2003).
4.5	Third Supplemental Indenture dated as of June 30, 2007, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Guarantor, and U.S. Bank National Association, as successor Trustee (incorporated by reference to Exhibit 4.55 to Form 10-Q filed on August 8, 2007) .
4.6	Amended and Restated Revolving Credit Agreement dated as of November 19, 2007 among Enterprise Products Operating LLC, the financial institutions party thereto as lenders, Wachovia Bank, National Association, as Administrative Agent, Issuing Bank and Swingline Lender, Citibank, N.A. and JPMorgan Chase Bank, as Co-Syndication Agents, and SunTrust Bank, Mizuho Corporate Bank, Ltd. and The Bank of Nova Scotia, as Co-Documentation Agents (incorporated by reference to Exhibit 10.1 to Form 8-K filed on November 20, 2007).

4.7	Amended and Restated Guaranty Agreement dated as of November 19, 2007 executed by Enterprise Products Partners L.P. in favor of Wachovia Bank, National Association, as Administrative Agent (incorporated by reference to Exhibit 10.2 to Form 8-K filed on November 20, 2007).
4.8	Indenture dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed on October 6, 2004).
4.9	First Supplemental Indenture dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed on October 6, 2004).
4.10	Second Supplemental Indenture dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed on October 6, 2004).
4.11	Third Supplemental Indenture dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.4 to Form 8-K filed on October 6, 2004).
4.12	Fourth Supplemental Indenture dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.5 to Form 8-K filed on October 6, 2004).
4.13	Fifth Supplemental Indenture dated as of March 2, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed on March 3, 2005).
4.14	Sixth Supplemental Indenture dated as of March 2, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed on March 3, 2005).
4.15	Seventh Supplemental Indenture dated as of June 1, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.46 to Form 10-Q filed November 4, 2005).
4.16	Eighth Supplemental Indenture dated as of July 18, 2006 to Indenture dated October 4, 2004 among Enterprise Products Operating L.P., as issuer, Enterprise Products Partners L.P., as parent guarantor, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to exhibit 4.2 to Form 8-K filed July 19, 2006).
4.17	Ninth Supplemental Indenture, dated as of May 24, 2007, by and among Enterprise Products Operating L.P., as issuer, Enterprise Products Partners L.P., as parent guarantor, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K filed by Enterprise Products Partners L.P. on May 24, 2007).
4.18	Tenth Supplemental Indenture, dated as of June 30, 2007, by and among Enterprise Products Operating LLC, as issuer, Enterprise Products Partners L.P., as parent guarantor, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.54 to Form 10-Q filed August 8, 2007).
4.19	Eleventh Supplemental Indenture, dated as of September 4, 2007, by and among Enterprise Products Operating LLC, as issuer, Enterprise Products Partners L.P., as parent guarantor, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed on September 5, 2007).
4.20	Global Note representing $350 million principal amount of 6.375% Series B Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Registration Statement on Form S-4, Reg. No. 333-102776, filed January 28, 2003).

4.21	Global Note representing $500 million principal amount of 6.875% Series B Senior Notes due 2033 with attached Guarantee (incorporated by reference to Exhibit 4.8 to Form 10-K filed March 31, 2003).
4.22	Global Notes representing $450 million principal amount of 7.50% Senior Notes due 2011 (incorporated by reference to Exhibit 4.1 to Form 8-K filed January 25, 2001).
4.23	Global Note representing $500 million principal amount of 4.000% Series B Senior Notes due 2007 with attached Guarantee (incorporated by reference to Exhibit 4.14 to Form S-3 Registration Statement Reg. No. 333-123150 filed on March 4, 2005).
4.24	Global Note representing $500 million principal amount of 5.600% Series B Senior Notes due 2014 with attached Guarantee (incorporated by reference to Exhibit 4.17 to Form S-3 Registration Statement Reg. No. 333-123150 filed on March 4, 2005).
4.25	Global Note representing $150 million principal amount of 5.600% Series B Senior Notes due 2014 with attached Guarantee (incorporated by reference to Exhibit 4.18 to Form S-3 Registration Statement Reg. No. 333-123150 filed on March 4, 2005).
4.26	Global Note representing $350 million principal amount of 6.650% Series B Senior Notes due 2034 with attached Guarantee (incorporated by reference to Exhibit 4.19 to Form S-3 Registration Statement Reg. No. 333-123150 filed on March 4, 2005).
4.27	Global Note representing $500 million principal amount of 4.625% Series B Senior Notes due 2009 with attached Guarantee (incorporated by reference to Exhibit 4.27 to Form 10-K for the year ended December 31, 2004 filed on March 15, 2005).
4.28	Global Note representing $250,000,000 principal amount of 5.00% Series B Senior Notes due 2015 with attached Guarantee (incorporated by reference to Exhibit 4.31 to Form 10-Q filed on November 4, 2005).
4.29	Global Note representing $250,000,000 principal amount of 5.75% Series B Senior Notes due 2035 with attached Guarantee (incorporated by reference to Exhibit 4.32 to Form 10-Q filed on November 4, 2005).
4.30	Global Note representing $500,000,000 principal amount of 4.95% Senior Notes due 2010 with attached Guarantee (incorporated by reference to Exhibit 4.47 to Form 10-Q filed November 4, 2005).
4.31	Form of Junior Note, including Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K file July 19, 2006).
4.32	Global Note representing $800,000,000 principal amount of 6.30% Senior Notes due 2017 with attached Guarantee (incorporated by reference to Exhibit 4.38 to Form 10-Q filed November 8, 2007).
4.33	Amended and Restated Credit Agreement dated as of June 29, 2005, among Cameron Highway Oil Pipeline Company, the Lenders party thereto, and SunTrust Bank, as Administrative Agent and Collateral Agent (incorporated by reference to Exhibit 4.1 to Form 8-K filed on July 1, 2005).
4.34	Replacement Capital Covenant, dated May 24, 2007, executed by Enterprise Products Operating L.P. and Enterprise Products Partners L.P. in favor of the covered debtholders described therein (incorporated by reference to Exhibit 99.1 to the Current Report on Form 8-K filed by Enterprise Products Partners L.P. on May 24, 2007).
4.35	First Amendment to Replacement Capital Covenant dated August 25, 2006, executed by Enterprise Products Operating L.P. in favor of the covered debtholders described therein (Incorporated by reference to Exhibit 99.2 to Form 8-K filed August 25, 2006).
4.36	Purchase Agreement, dated as of July 12, 2006 between Cerrito Gathering Company, Ltd., Cerrito Gas Marketing, Ltd., Encinal Gathering, Ltd., as Sellers, Lewis Energy Group, L.P. as Guarantor, and Enterprise Products Partners L.P., as buyer (incorporated by reference to Exhibit 4.6 to Form 10-Q filed August 8, 2006).
10.1	Transportation Contract between Enterprise Products Operating L.P. and Enterprise Transportation Company dated June 1, 1998 (incorporated by reference to Exhibit 10.3 to Registration Statement Form S-1/A filed July 8, 1998).
10.2***	Enterprise Products 1998 Long-Term Incentive Plan, amended and restated as of November 9 2007 (incorporated by reference to Exhibit 10.1 to Form 10-Q filed on November 8, 2007).
10.3***	Form of Option Grant Award under Enterprise Products 1998 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.2 to Form 10-Q filed on November 8, 2007).

10.4***	Form of Restricted Unit Grant under the Enterprise Products 1998 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.3 to Form 10-Q filed on November 8, 2007).
10.5***	EPE Unit L.P. Agreement of Limited Partnership (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed by Enterprise GP Holdings L.P., Commission file no. 1-32610, on September 1, 2005).
10.6***	First Amendment to EPE Unit L.P. Agreement of limited partnership dated August 7, 2007 (incorporated by reference to Exhibit 10.3 to Form 10-Q filed by Duncan Energy Partners L.P. on August 8, 2007).
10.7***	EPE Unit II, L.P. Agreement of Limited Partnership (incorporated by reference to Exhibit 10.13 to Form 10-K filed on February 28, 2007).
10.8***	First Amendment to EPE Unit II, L.P. Agreement of limited partnership dated August 7, 2007 (incorporated by reference to Exhibit 10.4 to Form 10-Q filed by Duncan Energy Partners L.P. on August 8, 2007).
10.9***	EPE Unit III, L.P. Agreement of Limited Partnership dated May 7, 2007 (incorporated by reference to Exhibit 10.6 to the Current Report on Form 8-K filed by Enterprise GP Holdings L.P. on May 10, 2007).
10.10***	First Amendment to EPE Unit III, L.P. Agreement of limited partnership dated August 7, 2007 (incorporated by reference to Exhibit 10.5 to Form 10-Q filed by Duncan Energy Partners L.P. on August 8, 2007).
10.11***	Enterprise Products Company 2005 EPE Long-Term Incentive Plan (amended and restated) (incorporated by reference to Exhibit 10.1 to Form 8-K filed by Enterprise GP Holdings L.P. on May 8, 2006).
10.12***	Form of Restricted Unit Grant under the Enterprise Products Company 2005 EPE Long-Term Incentive Plan (incorporated by reference to Exhibit 10.29 to Amendment No. 3 to Form S-1 Registration Statement (Reg. No. 333-124320) filed by Enterprise GP Holdings L.P. on August 11, 2005).
10.13***	Form of Phantom Unit Grant under the Enterprise Products Company 2005 EPE Long-Term Incentive Plan (incorporated by reference to Exhibit 10.30 to Amendment No. 3 to Form S-1 Registration Statement (Reg. No. 333-124320) filed by Enterprise GP Holdings L.P. on August 11, 2005).
10.14***	Form of Unit Appreciation Right Grant (Enterprise Products GP, LLC Directors) based upon the Enterprise Products Company 2005 EPE Long-Term Incentive Plan (incorporated by reference to Exhibit 10.3 to Form 8-K filed by Enterprise GP Holdings on May 8, 2006).
10.15***	Enterprise Products 2008 Long-Term Incentive Plan (incorporated by reference to Exhibit A to the Proxy Statement filed on December 31, 2007).
10.16	Fourth Amended and Restated Administrative Services Agreement by and among EPCO, Inc., Enterprise Products Partners L.P., Enterprise Products Operating L.P., Enterprise Products GP, LLC, Enterprise Products OLPGP, Inc., Enterprise GP Holdings L.P., EPE Holdings, LLC, DEP Holdings, LLC, Duncan Energy Partners L.P., DEP OLPGP, LLC, DEP Operating Partnership L.P., TEPPCO Partners, L.P., Texas Eastern Products Pipeline Company, LLC, TE Products Pipeline Company, Limited Partnership, TEPPCO Midstream Companies, L.P., TCTM, L.P. and TEPPCO GP, Inc. dated January 30, 2007, but effective as of February 5, 2007 (incorporated by reference to Exhibit 10 to Form 8-K filed February 5, 2007 by Duncan Energy Partners).
10.17	First Amendment to the Fourth Amended and Restated Administrative Services Agreement dated February 28, 2007 (incorporated by reference to Exhibit 10.8 to Form 10-K filed on February 28, 2007).
10.18	Second Amendment to Fourth Amended and Restated Administrative Services Agreement dated August 7, 2007, but effective as of May 7, 2007 (incorporated by reference to Exhibit 10.1 to Form 10-Q filed by Duncan Energy Partners L.P. on August 8, 2007).
10.19	Omnibus Agreement, dated as of February 5, 2007 by and among Enterprise Products Operating L.P., DEP Holdings, LLC, Duncan Energy Partners L.P., DEP OLPGP, LLC, DEP Operating Partnership, L.P., Enterprise Lou-Tex Propylene Pipeline L.P., Sabine Propylene Pipeline L.P., Acadian Gas, LLC, Mont Belvieu Caverns, LLC, South Texas NGL Pipelines, LLC (incorporated by reference to Exhibit 10.19 to Form 8-K filed February 5, 2007 by Duncan Energy Partners).
10.20	Contribution, Conveyance And Assumption Agreement dated as of February 5, 2007, by and among Enterprise Products Operating L.P., DEP Holdings, LLC, Duncan Energy Partners L.P., DEP OLPGP, LLC and DEP Operating Partnership, L.P. (incorporated by reference to Exhibit 1.1 to Form 8-K filed February 5, 2007 by Duncan Energy Partners).

10.21	Agreement and Release, dated May 31, 2007, between EPCO, Inc. and Robert G. Phillips (incorporated by reference to Exhibit 10.3 to Form 10-Q filed on August 8, 2007).
10.22	Revolving Credit Agreement, dated as of January 5, 2007, among Duncan Energy Partners L.P., as borrower, Wachovia Bank, National Association, as Administrative Agent, The Bank of Nova Scotia and Citibank, N.A., as Co-Syndication Agents, JPMorgan Chase Bank, N.A. and Mizuho Corporate Bank, Ltd., as Co-Documentation Agents, and Wachovia Capital Markets, LLC, The Bank of Nova Scotia and Citigroup Global Markets Inc., as Joint Lead Arrangers and Joint Book Runners (incorporated by reference to Exhibit 10.20 to Amendment No. 2 to Form S-1 Registration Statement (Reg. No. 333-138371) filed January 12, 2007).
10.23	First Amendment to Revolving Credit Agreement, dated as of June 30, 2007, among Duncan Energy Partners L.P., as borrower, Wachovia Bank, National Association, as Administrative Agent, The Bank of Nova Scotia and Citibank, N.A., as Co-Syndication Agents, JPMorgan Chase Bank, N.A. and Mizuho Corporate Bank, Ltd., as Co-Documentation Agents, and Wachovia Capital Markets, LLC, The Bank of Nova Scotia and Citigroup Global Markets Inc., as Joint Lead Arrangers and Joint Book Runners (incorporated by reference to Exhibit 4.2 to Form 10-Q filed August 8, 2007 by Duncan Energy Partners).
12.1#	Computation of ratio of earnings to fixed charges for each of the five years ended December 31, 2007, 2006, 2005, 2004 and 2003.
21.1#	List of subsidiaries as of February 1, 2008.
23.1#	Consent of Deloitte & Touche LLP dated February 28, 2008.
31.1#	Sarbanes-Oxley Section 302 certification of Michael A. Creel for Enterprise Products Partners L.P. for the December 31, 2007 annual report on Form 10-K.
31.2#	Sarbanes-Oxley Section 302 certification of W. Randall Fowler for Enterprise Products Partners L.P. for the December 31, 2007 annual report on Form 10-K.
32.1#	Section 1350 certification of Michael A. Creel for the December 31, 2007 annual report on Form 10-K.
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* With respect to any exhibits incorporated by reference to any Exchange Act filings, the Commission file number for Enterprise Products Partners L.P. is 1-14323.

*** Identifies management contract and compensatory plan arrangements.

Filed with this report.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized on February 29, 2008.

ENTERPRISE PRODUCTS PARTNERS L.P.
(A Delaware Limited Partnership)

By: Enterprise Products GP, LLC, as general partner

By: /s/ *Michael J. Knesek*
Name: Michael J. Knesek
Title: Senior Vice President, Controller and Principal Accounting Officer

Pursuant to the requirements of the Securities Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated below on February 29, 2008.

Signature	Title (Position with Enterprise Products GP, LLC)
/s/ *Dan L. Duncan* Dan L. Duncan	Director and Chairman
/s/ *Michael A. Creel* Michael A. Creel	Director, President and Chief Executive Officer
/s/ *W. Randall Fowler* W. Randall Fowler	Director, Executive Vice President and Chief Financial Officer
/s/ *Richard H. Bachmann* Richard H. Bachmann	Director, Executive Vice President, Chief Legal Officer and Secretary
/s/ *Dr. Ralph S. Cunningham* Dr. Ralph S. Cunningham	Director
/s/ *E. William Barnett* E. William Barnett	Director
/s/ *Charles M. Rampacek* Charles M. Rampacek	Director
/s/ *Rex C. Ross* Rex C. Ross	Director
/s/ *Michael J. Knesek* Michael J. Knesek	Senior Vice President, Controller and Principal Accounting Officer

Exhibit Index

Exhibits	Description of Exhibits
2.1	Merger Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products Management LLC, GulfTerra Energy Partners, L.P. and GulfTerra Energy Company, L.L.C. (incorporated by reference to Exhibit 2.1 to Form 8-K filed December 15, 2003).
2.2	Amendment No. 1 to Merger Agreement, dated as of August 31, 2004, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products Management LLC, GulfTerra Energy Partners, L.P. and GulfTerra Energy Company, L.L.C. (incorporated by reference to Exhibit 2.1 to Form 8-K filed September 7, 2004).
2.3	Parent Company Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products GTM, LLC, El Paso Corporation, Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso EPN Investments, L.L.C. and GulfTerra GP Holding Company (incorporated by reference to Exhibit 2.2 to Form 8-K filed December 15, 2003).
2.4	Amendment No. 1 to Parent Company Agreement, dated as of April 19, 2004, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products GTM, LLC, El Paso Corporation, Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso EPN Investments, L.L.C. and GulfTerra GP Holding Company (incorporated by reference to Exhibit 2.1 to the Form 8-K filed April 21, 2004).
2.5	Purchase and Sale Agreement (Gas Plants), dated as of December 15, 2003, by and between El Paso Corporation, El Paso Field Services Management, Inc., El Paso Transmission, L.L.C., El Paso Field Services Holding Company and Enterprise Products Operating L.P. (incorporated by reference to Exhibit 2.4 to Form 8-K filed December 15, 2003).
3.1	Certificate of Limited Partnership of Enterprise Products Partners L.P. (incorporated by reference to Exhibit 3.6 to Form 10-Q filed November 8, 2007).
3.2	Fifth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P., dated effective as of August 8, 2005 (incorporated by reference to Exhibit 3.1 to Form 8-K filed August 10, 2005).
3.3	First Amendment to Fifth Amended and Restated Partnership Agreement of Enterprise Products Partners L.P. dated as of December 27, 2007 (incorporated by reference to Exhibit 3.1 to Form 8-K/A filed January 3, 2008).
3.4	Fifth Amended and Restated Limited Liability Company Agreement of Enterprise Products GP, LLC, dated as of November 7, 2007 (incorporated by reference to Exhibit 3.2 to Form 10-Q filed November 8, 2007).
3.5	Limited Liability Company Agreement of Enterprise Products Operating LLC dated as of June 30, 2007 (incorporated by reference to Exhibit 3.3 to Form 10-Q filed on August 8, 2007).
3.6	Certificate of Incorporation of Enterprise Products OLPGP, Inc., dated December 3, 2003 (incorporated by reference to Exhibit 3.5 to Form S-4 Registration Statement, Reg. No. 333-121665, filed December 27, 2004).
3.7	Bylaws of Enterprise Products OLPGP, Inc., dated December 8, 2003 (incorporated by reference to Exhibit 3.6 to Form S-4 Registration Statement, Reg. No. 333-121665, filed December 27, 2004).
3.8	Certificate of Limited Partnership of Duncan Energy Partners L.P. (incorporated by reference to Exhibit 3.1 to Duncan Energy Partners L.P. Form S-1 Registration Statement, Reg. No. 333-138371, filed November 2, 2006).
3.9	Amended and Restated Agreement of Limited Partnership of Duncan Energy Partners L.P., dated February 5, 2007 (incorporated by reference to Exhibit 3.1 to Duncan Energy Partners L.P.'s Form 8-K/A filed February 5, 2007).
3.10	First Amendment to Amended and Restated Partnership Agreement of Duncan Energy Partners L.P. dated as of December 27, 2007 (incorporated by reference to Exhibit 3.1 to Duncan Energy Partners L.P.'s Form 8-K filed on January 3, 2008).
4.1	Form of Common Unit certificate (incorporated by reference to Exhibit 4.1 to Registration Statement on Form S-1/A; File No. 333-52537, filed July 21, 1998).
4.2	Indenture dated as of March 15, 2000, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and First Union National Bank, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed March 10, 2000).

Exhibits	Description of Exhibits
4.3	First Supplemental Indenture dated as of January 22, 2003, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Registration Statement on Form S-4, Reg. No. 333-102776, filed January 28, 2003).
4.4	Second Supplemental Indenture dated as of February 14, 2003, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 10-K filed March 31, 2003).
4.5	Third Supplemental Indenture dated as of June 30, 2007, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Guarantor, and U.S. Bank National Association, as successor Trustee (incorporated by reference to Exhibit 4.55 to Form 10-Q filed on August 8, 2007) .
4.6	Amended and Restated Revolving Credit Agreement dated as of November 19, 2007 among Enterprise Products Operating LLC, the financial institutions party thereto as lenders, Wachovia Bank, National Association, as Administrative Agent, Issuing Bank and Swingline Lender, Citibank, N.A. and JPMorgan Chase Bank, as Co-Syndication Agents, and SunTrust Bank, Mizuho Corporate Bank, Ltd. and The Bank of Nova Scotia, as Co-Documentation Agents (incorporated by reference to Exhibit 10.1 to Form 8-K filed on November 20, 2007).
4.7	Amended and Restated Guaranty Agreement dated as of November 19, 2007 executed by Enterprise Products Partners L.P. in favor of Wachovia Bank, National Association, as Administrative Agent (incorporated by reference to Exhibit 10.2 to Form 8-K filed on November 20, 2007).
4.8	Indenture dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed on October 6, 2004).
4.9	First Supplemental Indenture dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed on October 6, 2004).
4.10	Second Supplemental Indenture dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed on October 6, 2004).
4.11	Third Supplemental Indenture dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.4 to Form 8-K filed on October 6, 2004).
4.12	Fourth Supplemental Indenture dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.5 to Form 8-K filed on October 6, 2004).
4.13	Fifth Supplemental Indenture dated as of March 2, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed on March 3, 2005).
4.14	Sixth Supplemental Indenture dated as of March 2, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed on March 3, 2005).
4.15	Seventh Supplemental Indenture dated as of June 1, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.46 to Form 10-Q filed November 4, 2005).

Exhibits	Description of Exhibits
4.16	Eighth Supplemental Indenture dated as of July 18, 2006 to Indenture dated October 4, 2004 among Enterprise Products Operating L.P., as issuer, Enterprise Products Partners L.P., as parent guarantor, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to exhibit 4.2 to Form 8-K filed July 19, 2006).
4.17	Ninth Supplemental Indenture, dated as of May 24, 2007, by and among Enterprise Products Operating L.P., as issuer, Enterprise Products Partners L.P., as parent guarantor, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K filed by Enterprise Products Partners L.P. on May 24, 2007).
4.18	Tenth Supplemental Indenture, dated as of June 30, 2007, by and among Enterprise Products Operating LLC, as issuer, Enterprise Products Partners L.P., as parent guarantor, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.54 to Form 10-Q filed August 8, 2007).
4.19	Eleventh Supplemental Indenture, dated as of September 4, 2007, by and among Enterprise Products Operating LLC, as issuer, Enterprise Products Partners L.P., as parent guarantor, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed on September 5, 2007).
4.20	Global Note representing $350 million principal amount of 6.375% Series B Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Registration Statement on Form S-4, Reg. No. 333-102776, filed January 28, 2003).
4.21	Global Note representing $500 million principal amount of 6.875% Series B Senior Notes due 2033 with attached Guarantee (incorporated by reference to Exhibit 4.8 to Form 10-K filed March 31, 2003).
4.22	Global Notes representing $450 million principal amount of 7.50% Senior Notes due 2011 (incorporated by reference to Exhibit 4.1 to Form 8-K filed January 25, 2001).
4.23	Global Note representing $500 million principal amount of 4.000% Series B Senior Notes due 2007 with attached Guarantee (incorporated by reference to Exhibit 4.14 to Form S-3 Registration Statement Reg. No. 333-123150 filed on March 4, 2005).
4.24	Global Note representing $500 million principal amount of 5.600% Series B Senior Notes due 2014 with attached Guarantee (incorporated by reference to Exhibit 4.17 to Form S-3 Registration Statement Reg. No. 333-123150 filed on March 4, 2005).
4.25	Global Note representing $150 million principal amount of 5.600% Series B Senior Notes due 2014 with attached Guarantee (incorporated by reference to Exhibit 4.18 to Form S-3 Registration Statement Reg. No. 333-123150 filed on March 4, 2005).
4.16	Global Note representing $350 million principal amount of 6.650% Series B Senior Notes due 2034 with attached Guarantee (incorporated by reference to Exhibit 4.19 to Form S-3 Registration Statement Reg. No. 333-123150 filed on March 4, 2005).
4.27	Global Note representing $500 million principal amount of 4.625% Series B Senior Notes due 2009 with attached Guarantee (incorporated by reference to Exhibit 4.27 to Form 10-K for the year ended December 31, 2004 filed on March 15, 2005).
4.28	Global Note representing $250,000,000 principal amount of 5.00% Series B Senior Notes due 2015 with attached Guarantee (incorporated by reference to Exhibit 4.31 to Form 10-Q filed on November 4, 2005).
4.29	Global Note representing $250,000,000 principal amount of 5.75% Series B Senior Notes due 2035 with attached Guarantee (incorporated by reference to Exhibit 4.32 to Form 10-Q filed on November 4, 2005).
4.30	Global Note representing $500,000,000 principal amount of 4.95% Senior Notes due 2010 with attached Guarantee (incorporated by reference to Exhibit 4.47 to Form 10-Q filed November 4, 2005).
4.31	Form of Junior Note, including Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K file July 19, 2006).
4.32	Global Note representing $800,000,000 principal amount of 6.30% Senior Notes due 2017 with attached Guarantee (incorporated by reference to Exhibit 4.38 to Form 10-Q filed November 8, 2007).
4.33	Amended and Restated Credit Agreement dated as of June 29, 2005, among Cameron Highway Oil Pipeline Company, the Lenders party thereto, and SunTrust Bank, as Administrative Agent and Collateral Agent (incorporated by reference to Exhibit 4.1 to Form 8-K filed on July 1, 2005).

Exhibits	Description of Exhibits
4.34	Replacement Capital Covenant, dated May 24, 2007, executed by Enterprise Products Operating L.P. and Enterprise Products Partners L.P. in favor of the covered debtholders described therein (incorporated by reference to Exhibit 99.1 to the Current Report on Form 8-K filed by Enterprise Products Partners L.P. on May 24, 2007).
4.35	First Amendment to Replacement Capital Covenant dated August 25, 2006, executed by Enterprise Products Operating L.P. in favor of the covered debtholders described therein (Incorporated by reference to Exhibit 99.2 to Form 8-K filed August 25, 2006).
4.36	Purchase Agreement, dated as of July 12, 2006 between Cerrito Gathering Company, Ltd., Cerrito Gas Marketing, Ltd., Encinal Gathering, Ltd., as Sellers, Lewis Energy Group, L.P. as Guarantor, and Enterprise Products Partners L.P., as buyer (incorporated by reference to Exhibit 4.6 to Form 10-Q filed August 8, 2006).
10.1	Transportation Contract between Enterprise Products Operating L.P. and Enterprise Transportation Company dated June 1, 1998 (incorporated by reference to Exhibit 10.3 to Registration Statement Form S-1/A filed July 8, 1998).
10.2***	Enterprise Products 1998 Long-Term Incentive Plan, amended and restated as of November 9 2007 (incorporated by reference to Exhibit 10.1 to Form 10-Q filed on November 8, 2007).
10.3***	Form of Option Grant Award under Enterprise Products 1998 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.2 to Form 10-Q filed on November 8, 2007).
10.4***	Form of Restricted Unit Grant under the Enterprise Products 1998 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.3 to Form 10-Q filed on November 8, 2007).
10.5***	EPE Unit L.P. Agreement of Limited Partnership (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed by Enterprise GP Holdings L.P., Commission file no. 1-32610, on September 1, 2005).
10.6***	First Amendment to EPE Unit L.P. Agreement of limited partnership dated August 7, 2007 (incorporated by reference to Exhibit 10.3 to Form 10-Q filed by Duncan Energy Partners L.P. on August 8, 2007).
10.7***	EPE Unit II, L.P. Agreement of Limited Partnership (incorporated by reference to Exhibit 10.13 to Form 10-K filed on February 28, 2007).
10.8***	First Amendment to EPE Unit II, L.P. Agreement of limited partnership dated August 7, 2007 (incorporated by reference to Exhibit 10.4 to Form 10-Q filed by Duncan Energy Partners L.P. on August 8, 2007).
10.9***	EPE Unit III, L.P. Agreement of Limited Partnership dated May 7, 2007 (incorporated by reference to Exhibit 10.6 to the Current Report on Form 8-K filed by Enterprise GP Holdings L.P. on May 10, 2007).
10.10***	First Amendment to EPE Unit III, L.P. Agreement of limited partnership dated August 7, 2007 (incorporated by reference to Exhibit 10.5 to Form 10-Q filed by Duncan Energy Partners L.P. on August 8, 2007).
10.11***	Enterprise Products Company 2005 EPE Long-Term Incentive Plan (amended and restated) (incorporated by reference to Exhibit 10.1 to Form 8-K filed by Enterprise GP Holdings L.P. on May 8, 2006).
10.12***	Form of Restricted Unit Grant under the Enterprise Products Company 2005 EPE Long-Term Incentive Plan (incorporated by reference to Exhibit 10.29 to Amendment No. 3 to Form S-1 Registration Statement (Reg. No. 333-124320) filed by Enterprise GP Holdings L.P. on August 11, 2005).
10.13***	Form of Phantom Unit Grant under the Enterprise Products Company 2005 EPE Long-Term Incentive Plan (incorporated by reference to Exhibit 10.30 to Amendment No. 3 to Form S-1 Registration Statement (Reg. No. 333-124320) filed by Enterprise GP Holdings L.P. on August 11, 2005).
10.14***	Form of Unit Appreciation Right Grant (Enterprise Products GP, LLC Directors) based upon the Enterprise Products Company 2005 EPE Long-Term Incentive Plan (incorporated by reference to Exhibit 10.3 to Form 8-K filed by Enterprise GP Holdings on May 8, 2006).
10.15	Fourth Amended and Restated Administrative Services Agreement by and among EPCO, Inc., Enterprise Products Partners L.P., Enterprise Products Operating L.P., Enterprise

Exhibits	Description of Exhibits
	Products GP, LLC, Enterprise Products OLPGP, Inc., Enterprise GP Holdings L.P., EPE Holdings, LLC, DEP Holdings, LLC, Duncan Energy Partners L.P., DEP OLPGP, LLC, DEP Operating Partnership L.P., TEPPCO Partners, L.P., Texas Eastern Products Pipeline Company, LLC, TE Products Pipeline Company, Limited Partnership, TEPPCO Midstream Companies, L.P., TCTM, L.P. and TEPPCO GP, Inc. dated January 30, 2007, but effective as of February 5, 2007 (incorporated by reference to Exhibit 10 to Form 8-K filed February 5, 2007 by Duncan Energy Partners).
10.16	First Amendment to the Fourth Amended and Restated Administrative Services Agreement dated February 28, 2007 (incorporated by reference to Exhibit 10.8 to Form 10-K filed on February 28, 2007).
10.17	Second Amendment to Fourth Amended and Restated Administrative Services Agreement dated August 7, 2007, but effective as of May 7, 2007 (incorporated by reference to Exhibit 10.1 to Form 10-Q filed by Duncan Energy Partners L.P. on August 8, 2007).
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10.22	First Amendment to Revolving Credit Agreement, dated as of June 30, 2007, among Duncan Energy Partners L.P., as borrower, Wachovia Bank, National Association, as Administrative Agent, The Bank of Nova Scotia and Citibank, N.A., as Co-Syndication Agents, JPMorgan Chase Bank, N.A. and Mizuho Corporate Bank, Ltd., as Co-Documentation Agents, and Wachovia Capital Markets, LLC, The Bank of Nova Scotia and Citigroup Global Markets Inc., as Joint Lead Arrangers and Joint Book Runners (incorporated by reference to Exhibit 4.2 to Form 10-Q filed August 8, 2007 by Duncan Energy Partners).
12.1#	Computation of ratio of earnings to fixed charges for each of the five years ended December 31, 2007, 2006, 2005, 2004 and 2003.
21.1#	List of subsidiaries as of February 1, 2008.
23.1#	Consent of Deloitte & Touche LLP.
31.1#	Sarbanes-Oxley Section 302 certification of Michael A. Creel for Enterprise Products Partners L.P. for the December 31, 2007 annual report on Form 10-K.
31.2#	Sarbanes-Oxley Section 302 certification of W. Randall Fowler for Enterprise Products Partners L.P. for the December 31, 2007 annual report on Form 10-K.
32.1#	Section 1350 certification of Michael A. Creel for the December 31, 2007 annual report on Form 10-K.
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* With respect to any exhibits incorporated by reference to any Exchange Act filings, the Commission file number for Enterprise Products Partners L.P. is 1-14323.

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*** Identifies management contract and compensatory plan arrangements.

Filed with this report.

Section 2: EX-12.1 (COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES)

EXHIBIT 12.1

ENTERPRISE PRODUCTS PARTNERS L.P.
COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES
(Dollars in thousands)

	For the Year Ended December 31,				
	2007	2006	2005	2004	2003
Consolidated income	$ 533,674	$601,155	$419,508	$268,261	$104,546
Add: Minority interest	30,643	9,079	5,760	8,128	3,859
Provision for taxes	15,257	21,323	8,362	3,761	5,293
Less: Equity in (income) loss of unconsolidated affiliates	(29,658)	(21,565)	(14,548)	(52,787)	13,960
Consolidated pre-tax income before minority interest and equity earnings from unconsolidated affiliates	549,916	609,992	419,082	227,363	127,658
Add: Fixed charges	400,065	306,791	264,921	168,463	151,338
Amortization of capitalized interest	9,335	7,894	1,644	974	579
Distributed income of equity investees	73,593	43,032	56,058	68,027	31,882
Subtotal	1,032,909	967,709	741,705	464,827	311,457
Less: Interest capitalized	(75,476)	(55,660)	(22,046)	(2,766)	(1,595)
Minority interest	(30,643)	(9,079)	(5,760)	(8,128)	(3,859)
Total earnings	$ 926,790	$902,970	$713,899	$453,933	$306,003
Fixed charges:					
Interest expense	$ 311,764	$238,023	$230,549	$155,740	$140,806
Capitalized interest	75,476	55,660	22,046	2,766	1,595
Interest portion of rental expense	12,825	13,108	12,326	9,957	8,937
Total	$ 400,065	$306,791	$264,921	$168,463	$151,338
Ratio of earnings to fixed charges	2.32x	2.94x	2.69x	2.69x	2.02x

These computations take into account our consolidated operations and the distributed income from our equity method investees. For purposes of these calculations, "earnings" is the amount resulting from adding and subtracting the following items:

Add the following, as applicable:

- consolidated pre-tax income before minority interest and income or loss from equity investees;
- fixed charges;
- amortization of capitalized interest;
- distributed income of equity investees; and
- our share of pre-tax losses of equity investees for which charges arising from guarantees are included in fixed charges.

From the subtotal of the added items, subtract the following, as applicable:

- interest capitalized;
- preference security dividend requirements of consolidated subsidiaries; and
- minority interest in pre-tax income of subsidiaries that have not incurred fixed charges.

The term "fixed charges" means the sum of the following: interest expensed and capitalized; amortized premiums, discounts and capitalized expenses related to indebtedness; an estimate of interest within rental expenses; and preference dividend requirements of consolidated subsidiaries.

Section 3: EX-21.1 (LIST OF SUBSIDIARIES)

Exhibit 21.1

LIST OF SUBSIDIARIES
Enterprise Products Partners L.P.
as of February 1, 2008

Name of Subsidiary	Jurisdiction of Formation	Effective Ownership
Acadian Gas, LLC	Delaware	Enterprise Products Operating LLC — 34% DEP Operating Partnership, L.P. — 66%
Acadian Gas Pipeline System	Texas	TXO-Acadian Gas Pipeline, LLC — 50% MCN-Acadian Gas Pipeline, LLC — 50%
Adamana Land Company, LLC	Delaware	Enterprise Products Operating LLC — 100%
Arizona Gas Storage, L.L.C.	Delaware	Enterprise Arizona Gas, L.L.C. — 60% Third Party — 40%
Atlantis Offshore, LLC	Delaware	Manta Ray Gathering Company, L.L.C. — 50% Manta Ray Offshore Gathering Company, L.L.C. — 50%
Baton Rouge Fractionators LLC	Delaware	Enterprise Products Operating LLC — 32.25% Third Parties — 67.75%
Baton Rouge Pipeline LLC	Delaware	Baton Rouge Fractionators LLC — 100%
Baton Rouge Propylene Concentrator, LLC	Delaware	Enterprise Products Operating LLC — 30% Third Parties — 70%
Belle Rose NGL Pipeline, L.L.C.	Delaware	Enterprise NGL Pipelines, LLC 41.67% Enterprise Products Operating LLC — 41.67% Third Parties — 16.66%
Belvieu Environmental Fuels GP, LLC	Delaware	Enterprise Products Operating LLC — 100%
Belvieu Environmental Fuels LLC	Texas	Enterprise Products Operating LLC — 99% Belvieu Environmental Fuels GP, LLC — 1%
Cajun Pipeline Company, LLC	Texas	Enterprise Products Operating LLC — 100%
Calcasieu Gas Gathering System	Texas	TXO-Acadian Gas Pipeline, LLC — 50% MCN-Acadian Gas Pipeline, LLC — 50%
Cameron Highway Oil Pipeline Company	Delaware	Cameron Highway Pipeline I, L.P. — 50% Third Party — 50%
Cameron Highway Pipeline GP, L.L.C.	Delaware	Enterprise GTM Holdings L.P. — 100%
Cameron Highway Pipeline I, L.P.	Delaware	Enterprise GTM Holdings L.P. — 99% Cameron Highway Pipeline GP, L.L.C. — 1%
Canadian Enterprise Gas Products, Ltd	Alberta, Canada	Enterprise Products Operating LLC — 100%
Chunchula Pipeline Company, LLC	Texas	Enterprise Products Operating LLC — 100%
Crystal Holding, L.L.C.	Delaware	Enterprise GTM Holdings L.P. — 100%
Cypress Gas Marketing, LLC	Delaware	Acadian Gas, LLC — 100%
Cypress Gas Pipeline, LLC	Delaware	Acadian Gas, LLC — 100%
Deep Gulf Development, LLC	Delaware	Enterprise Offshore Development, LLC — 90% Third Party — 10%
Deepwater Gateway, L.L.C.	Delaware	Enterprise Field Services, L.L.C. — 50% Third Party — 50%
DEP Holdings LLC	Delaware	Enterprise Products Operating LLC — 100%
DEP OLPGP, LLC	Delaware	Duncan Energy Partners L.P. — 100%
DEP Operating Partnership, L.P.	Delaware	Duncan Energy Partners L.P. — 99.999% DEP OLPGP, LLC — 0.001%
Dixie Pipeline Company	Delaware	Enterprise Products Operating LLC — 42.9% Enterprise NGL Pipelines, LLC — 31.3% Third Parties — 25.8%

Dixie Terminalling Company	Delaware	Dixie Pipeline Company — 100%
Duncan Energy Partners, L.P.	Delaware	Enterprise Products Operating LLC — 26.4% DEP Holdings LLC — 2% Public — 71.6%
E-Cypress, LLC	Delaware	Enterprise Products Operating LLC — 100%
E-Oaktree, LLC	Delaware	E-Cypress, LLC — 100%
Enterprise Alabama Intrastate, L.L.C.	Delaware	Enterprise GTM Holdings L.P. — 100%
Enterprise Arizona Gas, L.L.C.	Delaware	Enterprise Field Services, L.L.C. — 100%
Enterprise Energy Finance Corporation	Delaware	Enterprise GTM Holdings L.P. — 100%
Enterprise Field Services, LLC	Delaware	Enterprise GTM Holdings L.P. — 100%
Enterprise Fractionation, LLC	Delaware	Enterprise Products Operating LLC — 100%
Enterprise GC, L.P.	Delaware	Enterprise GTM Holdings L.P. — 99% Enterprise Holding III, L.L.C. — 1%
Enterprise GTMGP, LLC	Delaware	Enterprise Products GTM, LLC — 100%
Enterprise GTM Hattiesburg Storage, LLC	Delaware	Crystal Holding, L.L.C. — 100%
Enterprise GTM Holdings L.P.	Delaware	Enterprise Products Operating LLC — 99% Enterprise GTMGP, LLC — 1%
Enterprise GTM Offshore Operating Company, LLC	Delaware	Enterprise GTM Holdings L.P. — 100%
Enterprise Gas Liquids LLC	Delaware	Enterprise Products Operating LLC — 100%
Enterprise Gas Processing LLC	Delaware	Enterprise Products Operating LLC — 100%
Enterprise Holding III, L.L.C.	Delaware	Enterprise GTM Holdings L.P. — 100%
Enterprise Hydrocarbons L.P.	Delaware	Enterprise Products Texas Operating LLC — 99% Enterprise Products Operating LLC — 1%
Enterprise Intrastate L.P.	Delaware	Enterprise GTM Holdings L.P. — 99% Enterprise Holding III, L.L.C. — 1%
Enterprise Lou-Tex NGL Pipeline L.P.	Delaware	Enterprise Products Operating LLC — 99% HSC Pipeline Partnership L.P. — 1%
Enterprise Lou-Tex Propylene Pipeline L.P.	Delaware	Enterprise Products Operating LLC — 33% Propylene Pipeline Partnership L.P. — 1% DEP Operating Partnership, L.P. — 66%
Enterprise New Mexico Ventures, LLC	Delaware	Enterprise Field Services, LLC — 100%
Enterprise NGL Pipelines, LLC	Delaware	Enterprise Products Operating LLC — 100%
Enterprise NGL Private Lines & Storage, LLC	Delaware	Enterprise Products Operating LLC — 100%
Enterprise Offshore Development, LLC	Delaware	Moray Pipeline Company, LLC — 100%
Enterprise Products GTM, LLC	Delaware	Enterprise Products Operating LLC — 100%
Enterprise Products OLPGP, Inc.	Delaware	Enterprise Products Partners L.P. — 100%
Enterprise Products Operating LLC	Texas	Enterprise Products Partners L.P. — 99.999% Enterprise Products OLPGP, Inc. — 0.001%
Enterprise Products Texas Operating LLC	Texas	Enterprise Products Operating LLC — 99% Enterprise OLPGP, Inc.— 1%
Enterprise South Texas Gathering, L.P.	Delaware	Enterprise Products Operating, L.P. — 99% Enterprise OLPGP, Inc. — 1%
Enterprise Terminalling LLC	Texas	Enterprise Products Operating LLC — 99% Enterprise Gas Liquids LLC 1%
Enterprise Terminals & Storage, LLC	Delaware	Mapletree, LLC — 100%
Enterprise Texas Pipeline LLC	Texas	Enterprise GTM Holdings L.P. — 99% Enterprise Holding III, L.L.C. — 1%
Enterprise White River Hub, LLC	Delaware	Enterprise Products Operating LLC — 100%
EPOLP 1999 Grantor Trust	Texas	Enterprise Products Operating LLC — 100%

Evangeline Gas Corp.	Delaware	Evangeline Gulf Coast Gas, LLC — 45.05% Third Parties — 54.95%
Evangeline Gas Pipeline Company L.P.	Delaware	Evangeline Gulf Coast Gas, LLC — 45% Evangeline Gas Corp. — 10% Third Party — 45%
Evangeline Gulf Coast Gas, LLC	Delaware	Acadian Gas, LLC — 100%
First Reserve Gas, L.L.C.	Delaware	Crystal Holding, L.L.C. — 100%
Flextrend Development Company, L.L.C.	Delaware	Enterprise GTM Holdings L.P. — 100%
Groves RGP Pipeline LLC	Texas	Enterprise Products Operating LLC — 99% Enterprise Products Texas Operating LLC — 1%
Hattiesburg Gas Storage Company	Delaware	First Reserve Gas, L.L.C. — 50% Hattiesburg Industrial Gas Sales, L.L.C. — 50%
Hattiesburg Industrial Gas Sales, L.L.C.	Delaware	First Reserve Gas, L.L.C. — 100%
High Island Offshore System, L.L.C.	Delaware	Enterprise GTM Holdings L.P. — 100%
HSC Pipeline Partnership, LLC	Texas	Enterprise Products Operating LLC — 99% Enterprise OLPGP, Inc.— 1%
Independence Hub, LLC	Delaware	Enterprise Field Services, LLC — 80% Third Party — 20%
Jonah Gas Gathering Company	Wyoming	TEPPCO Midstream Companies, LLC — 80.64% Enterprise Gas Processing LLC — 19.36%
Jonah Gas Marketing, LLC	Delaware	Jonah Gas Gathering Company — 100%
K/D/S Promix, L.L.C.	Delaware	Enterprise Fractionation, LLC — 50% Third Parties — 50%
La Porte Pipeline Company L.P.	Texas	Enterprise Products Operating LLC — 49.5% La Porte Pipeline GP, LLC — 1.0% Third Parties — 49.5%
La Porte Pipeline GP, L.L.C.	Delaware	Enterprise Products Operating LLC — 50% Third Parties — 50%
Mapletree, LLC	Delaware	Enterprise Products Operating LLC — 100%
MCN Acadian Gas Pipeline, LLC	Delaware	Acadian Gas, LLC — 100%
MCN Pelican Interstate Gas, LLC	Delaware	Acadian Gas, LLC — 100%
Manta Ray Gathering Company, L.L.C.	Delaware	Enterprise GTM Holdings L.P. — 100%
Manta Ray Offshore Gathering Company, L.L.C.	Delaware	Neptune Pipeline Company, L.L.C. — 100%
Mid-America Pipeline Company, LLC	Delaware	Mapletree, LLC — 100%
Mont Belvieu Caverns, LLC	Delaware	Enterprise Products Operating, L.P. — 33.365% Enterprise Products OLPGP, Inc. — 0.635% DEP Operating Partnership, L.P. — 66%
Moray Pipeline Company, LLC	Delaware	Enterprise Products Operating LLC — 100%
Nautilus Pipeline Company L.L.C.	Delaware	Neptune Pipeline Company, L.L.C. — 100%
Neches Pipeline System	Delaware	TXO-Acadian Gas Pipeline, LLC — 50% MCN-Acadian Gas Pipeline, LLC — 50%
Nemo Gathering Company, LLC	Delaware	Moray Pipeline Company, LLC — 33.92% Third Parties — 66.08%
Neptune Pipeline Company, L.L.C.	Delaware	Sailfish Pipeline Company, L.L.C. — 25.67% Third Parties — 74.33%
Norco-Taft Pipeline, LLC	Delaware	Enterprise NGL Private Lines & Storage, LLC — 100%
Olefins Terminal Corporation	Delaware	Enterprise Products Operating LLC — 1000%
Petal Gas Storage, L.L.C.	Delaware	Crystal Holding, L.L.C. — 100%

Pontchartrain Natural Gas System	Texas	TXO-Acadian Gas Pipeline, LLC — 50% MCN-Acadian Gas Pipeline, LLC — 50%
Port Neches GP, LLC	Delaware	Enterprise Products Operating LLC — 100%
Port Neches Pipeline LLC	Texas	Enterprise Products Operating LLC — 99% Port Neches GP, LLC — 1%
Poseidon Oil Pipeline Company, L.L.C.	Delaware	Poseidon Pipeline Company, L.L.C. — 36% Third Parties — 64%
Poseidon Pipeline Company, L.L.C.	Delaware	Enterprise GTM Holdings L.P. — 100%
Propylene Pipeline Partnership, L.P.	Texas	Enterprise Products Operating LLC — 99% Enterprise OLPGP, Inc. — 1%
Sabine Propylene Pipeline L.P.	Texas	Enterprise Products Operating LLC — 33% Propylene Pipeline Partnership L.P. — 1% DEP Operating Partnership, L.P. — 66%
Sailfish Pipeline Company, L.L.C.	Delaware	Enterprise Products Operating LLC — 100%
Seminole Pipeline Company	Delaware	E-Oaktree, LLC — 80% E-Cypress, LLC — 10% Third Party — 10%
Sorrento Pipeline Company, LLC	Texas	Enterprise Products Operating LLC — 100%
South Texas NGL Pipeline LLC	Delaware	Enterprise Products Operating LLC — 34% DEP Operating Partnership, L.P. — 66%
TECO Gas Processing, LLC	Delaware	Enterprise Products Operating LLC — 100%
TECO Gas Gathering, LLC	Delaware	Enterprise Products Operating LLC — 100%
Tejas-Magnolia Energy, LLC	Delaware	Pontchartrain Natural Gas System — 96.6% MCN-Pelican Interstate Gas, LLC — 3.4%
Tri-States NGL Pipeline, L.L.C.	Delaware	Enterprise Products Operating LLC — 33.3% Enterprise NGL Pipelines, LLC — 33.3% Third Parties — 33.3%
TXO-Acadian Gas Pipeline, LLC	Delaware	Acadian Gas, LLC — 100%
Venice Energy Services Company, L.L.C.	Delaware	Enterprise Gas Processing LLC — 13.1% Third Parties — 86.99%
Wilprise Pipeline Company, LLC	Delaware	Enterprise Products Operating LLC — 74.7% Third Parties — 25.3%

Section 4: EX-23.1 (CONSENT OF DELOITTE & TOUCHE LLP)

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in (i) Registration Statement Nos. 333-36856, 333-82486, 333-115633, 333-115634 of Enterprise Products Partners L.P. on Form S-8; (ii) Registration Statement No. 333-123150 of Enterprise Products Partners L.P. and Enterprise Products Operating LLC on Form S-3; and (iii) Registration Statement Nos. 333-107073, 333-114758, 333-136534, 333-142106, 333-145709 of Enterprise Products Partners L.P. on Form S-3 of our reports dated February 28, 2008, relating to the financial statements of Enterprise Products Partners L.P. and the effectiveness of Enterprise Products Partners L.P.'s internal control over financial reporting, appearing in this Annual Report on Form 10-K of Enterprise Products Partners L.P. for the year ended December 31, 2007.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 28, 2008

Section 5: EX-31.1 (CERTIFICATION PURSUANT TO SECTION 302)

EXHIBIT 31.1

CERTIFICATIONS

I, Michael A. Creel, certify that:

1. I have reviewed this annual report on Form 10-K of Enterprise Products Partners L.P.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15 (f)) for the registrant and have:
   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 29, 2008

/s/ Michael A. Creel

Name: Michael A. Creel
Title: Principal Executive Officer of our General Partner, Enterprise Products GP, LLC

Section 6: EX-31.2 (CERTIFICATION PURSUANT TO SECTION 302)

EXHIBIT 31.2

CERTIFICATIONS

I, W. Randall Fowler, certify that:

1. I have reviewed this annual report on Form 10-K of Enterprise Products Partners L.P.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15 (f)) for the registrant and have:
   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 29, 2008

/s/ W. Randall Fowler
Name: W. Randall Fowler
Title: Principal Financial Officer of our General Partner,
Enterprise Products GP, LLC

Section 7: EX-32.1 (CERTIFICATION PURSUANT TO SECTION 1350)

EXHIBIT 32.1

SARBANES-OXLEY SECTION 906 CERTIFICATION

CERTIFICATION OF MICHAEL A. CREEL, CHIEF EXECUTIVE OFFICER OF ENTERPRISE PRODUCTS GP, LLC, THE GENERAL PARTNER OF ENTERPRISE PRODUCTS PARTNERS L.P.

In connection with this annual report of Enterprise Products Partners L.P. (the "Registrant") on Form 10-K for the year ended December 31, 2007 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Michael A. Creel, Chief Executive Officer of Enterprise Products GP, LLC, the general partner of the Registrant, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Registrant.

/s/ Michael A. Creel
Name: Michael A. Creel
Title: Chief Executive Officer of Enterprise Products GP, LLC
on behalf of Enterprise Products Partners L.P.

Date: February 29, 2008

Section 8: EX-32.2 (CERTIFICATION PURSUANT TO SECTION 1350)

EXHIBIT 32.2

SARBANES-OXLEY SECTION 906 CERTIFICATION

CERTIFICATION OF W. RANDALL FOWLER, CHIEF FINANCIAL OFFICER OF ENTERPRISE PRODUCTS GP, LLC, THE GENERAL PARTNER OF ENTERPRISE PRODUCTS PARTNERS L.P.

In connection with this annual report of Enterprise Products Partners L.P. (the "Registrant") on Form 10-K for the year ended December 31, 2007 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, W. Randall Fowler, Chief Financial Officer of Enterprise Products GP, LLC, the general partner of the Registrant, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Registrant.

/s/ W. Randall Fowler

Name: W. Randall Fowler
Title: Chief Financial Officer of Enterprise Products GP, LLC
on behalf of Enterprise Products Partners L.P.

Date: February 29, 2008

KMP 10-Q 9/30/2008

Section 1: 10-Q (FORM 10-Q)

F O R M 10-Q

SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended **September 30, 2008**

or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from _____to_____

Commission file number: **1-11234**

KINDER MORGAN ENERGY PARTNERS, L.P.
(Exact name of registrant as specified in its charter)

DELAWARE (State or other jurisdiction of incorporation or organization)	**76-0380342** (I.R.S. Employer Identification No.)

500 Dallas Street, Suite 1000, Houston, Texas 77002
(Address of principal executive offices)(zip code)
Registrant's telephone number, including area code: **713-369-9000**

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15 (d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Securities Exchange Act of 1934). Yes ☐ No ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Securities Exchange Act of 1934.
Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐

The Registrant had 179,069,427 common units outstanding as of October 31, 2008.

KINDER MORGAN ENERGY PARTNERS, L.P.
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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements.

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
(In Millions Except Per Unit Amounts)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	**2007**	**2008**	**2007**
Revenues				
Natural gas sales	$ 2,183.3	$ 1,365.7	$ 6,369.2	$ 4,314.6
Services	700.2	624.1	2,053.7	1,776.8
Product sales and other	349.3	241.0	1,025.9	677.5
	3,232.8	2,230.8	9,448.8	6,768.9
Costs, Expenses and Other				
Gas purchases and other costs of sales	2,179.4	1,371.7	6,405.7	4,296.0
Operations and maintenance	279.9	249.6	739.6	649.4
Fuel and power	73.6	60.7	208.5	171.3
Depreciation, depletion and amortization	166.8	138.0	490.5	401.8
General and administrative	73.1	63.0	222.7	222.7
Taxes, other than income taxes	48.0	38.9	147.0	112.0
Goodwill impairment expense	—	—	—	377.1
Other expense (income)	4.1	(2.5)	1.3	(11.9)
	2,824.9	1,919.4	8,215.3	6,218.4
Operating Income	407.9	311.4	1,233.5	550.5
Other Income (Expense)				
Earnings from equity investments	34.6	15.8	118.5	51.4
Amortization of excess cost of equity investments	(1.4)	(1.4)	(4.3)	(4.3)
Interest, net	(98.3)	(102.4)	(293.8)	(290.3)
Other, net	4.3	5.0	30.5	9.4
Minority Interest	(3.1)	(2.4)	(11.2)	(4.4)
Income from Continuing Operations Before Income Taxes	344.0	226.0	1,073.2	312.3
Income Taxes	(14.2)	(20.8)	(35.8)	(36.4)
Income from Continuing Operations	329.8	205.2	1,037.4	275.9
Discontinued Operations (Note 2):				
Income from operations of North System	—	8.6	—	21.1
Adjustment to gain on disposal of North System	—	—	1.3	—
Income from Discontinued Operations	—	8.6	1.3	21.1
Net Income	$ 329.8	$ 213.8	$ 1,038.7	$ 297.0
Calculation of Limited Partners' interest in Net Income (Loss):				
Income from Continuing Operations	$ 329.8	$ 205.2	$ 1,037.4	$ 275.9
Less: General Partner's interest	(205.6)	(155.7)	(588.9)	(439.9)
Limited Partners' interest	124.2	49.5	448.5	(164.0)
Add: Limited Partners' interest in Discontinued Operations	—	8.5	1.3	20.9

Limited Partners’ interest in Net Income (Loss)	$ 124.2	$ 58.0	$ 449.8	$ (143.1)
Basic and Diluted Limited Partners’ Net Income (Loss) per Unit:				
Income (Loss) from Continuing Operations	$ 0.48	$ 0.21	$ 1.76	$ (0.70)
Income from Discontinued Operations	—	0.03	—	0.09
Net Income (Loss)	$ 0.48	$ 0.24	$ 1.76	$ (0.61)
Weighted average number of units used in computation of Limited Partners’ Net Income (Loss) per unit:				
Basic	258.8	239.0	255.5	235.0
Diluted	258.8	239.0	255.5	235.1
Per unit cash distribution declared	$ 1.02	$ 0.88	$ 2.97	$ 2.56

The accompanying notes are an integral part of these consolidated financial statements.

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(In Millions)
(Unaudited)

	September 30, 2008	December 31, 2007
ASSETS		
Current Assets		
Cash and cash equivalents	$ 52.8	$ 58.9
Restricted deposits	27.6	67.9
Accounts, notes and interest receivable, net		
Trade	961.1	960.2
Related parties	13.9	3.6
Inventories		
Products	22.5	19.5
Materials and supplies	21.7	18.3
Gas imbalances		
Trade	6.3	21.2
Related parties	—	5.7
Other current assets	66.3	54.4
	1,172.2	1,209.7
Property, Plant and Equipment, net	12,982.7	11,591.3
Investments	943.0	655.4
Notes receivable		
Trade	0.1	0.1
Related parties	192.7	87.9
Goodwill	1,087.7	1,077.8
Other intangibles, net	209.5	238.6
Deferred charges and other assets	451.0	317.0
Total Assets	$ 17,038.9	$ 15,177.8
LIABILITIES AND PARTNERS' CAPITAL		
Current Liabilities		
Accounts payable		
Cash book overdrafts	$ 70.7	$ 19.0
Trade	824.6	926.7
Related parties	22.5	22.6
Current portion of long-term debt	284.7	610.2
Accrued interest	65.9	131.2
Accrued taxes	92.6	73.8
Deferred revenues	29.9	22.8
Gas imbalances		
Trade	11.8	23.7
Related parties	8.0	—
Accrued other current liabilities	811.4	728.3
	2,222.1	2,558.3
Long-Term Liabilities and Deferred Credits		
Long-term debt		
Outstanding	8,056.2	6,455.9
Value of interest rate swaps	213.0	152.2
	8,269.2	6,608.1
Deferred revenues	16.4	14.2
Deferred income taxes	209.3	202.4
Asset retirement obligations	74.2	50.8
Other long-term liabilities and deferred credits	1,427.0	1,254.1
	9,996.1	8,129.6

Commitments and Contingencies (Note 3)		
Minority Interest	57.9	54.2
Partners' Capital		
Common Units	3,430.4	3,048.4
Class B Units	98.4	102.0
i-Units	2,562.3	2,400.8
General Partner	193.4	161.1
Accumulated other comprehensive loss	(1,521.7)	(1,276.6)
	4,762.8	4,435.7
Total Liabilities and Partners' Capital	$ 17,038.9	$ 15,177.8

The accompanying notes are an integral part of these consolidated financial statements.

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Increase/Decrease) in Cash and Cash Equivalents in Millions)
(Unaudited)

	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
Cash Flows From Operating Activities		
Net Income	$ 1,038.7	$ 297.0
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	490.5	408.8
Amortization of excess cost of equity investments	4.3	4.3
Impairment of goodwill	—	377.1
Income from (i) the sale of property, plant and equipment; (ii) the sale of investments; and (iii) property casualty indemnifications	(13.0)	(12.2)
Earnings from equity investments	(118.5)	(53.2)
Distributions from equity investments	115.3	87.9
Proceeds from termination of interest rate swap agreement	—	15.0
Changes in components of working capital:		
Accounts receivable	(13.6)	210.6
Other current assets	11.1	4.0
Inventories	(6.8)	1.8
Accounts payable	(90.6)	(136.6)
Accrued interest	(65.3)	(17.0)
Accrued liabilities	68.4	(11.6)
Accrued taxes	18.9	57.6
Rate reparations, refunds and other litigation reserve adjustments	(10.7)	—
Other, net	4.4	21.2
Net Cash Provided by Operating Activities	1,433.1	1,254.7
Cash Flows From Investing Activities		
Acquisitions of assets and investments	(9.0)	(161.7)
Repayment (Payment) for Trans Mountain Pipeline	23.4	(549.1)
Additions to property, plant and equip. for expansion and maintenance projects	(1,914.4)	(1,142.9)
Sale of property, plant and equipment, and other net assets net of removal costs	48.8	11.6
Property casualty indemnifications	—	8.0
Net proceeds from (Investments in) margin deposits	40.3	(40.3)
Contributions to equity investments	(341.6)	(46.6)
Distributions from equity investments	89.1	—
Natural gas stored underground and natural gas liquids line-fill	(2.5)	12.3
Net Cash Used in Investing Activities	(2,065.9)	(1,908.7)
Cash Flows From Financing Activities		
Issuance of debt	6,575.7	6,206.6
Payment of debt	(5,293.8)	(4,941.0)
Repayments from related party	1.8	2.2
Debt issue costs	(11.2)	(13.5)
Increase (Decrease) in cash book overdrafts	51.7	(9.3)
Proceeds from issuance of common units	384.3	—
Proceeds from issuance of i-units	—	297.9
Contributions from minority interest	6.7	4.8
Distributions to partners:		
Common units	(501.9)	(409.1)
Class B units	(15.2)	(13.3)
General Partner	(557.6)	(410.3)
Minority interest	(13.9)	(11.9)
Other, net	3.1	0.1

Net Cash Provided by Financing Activities	629.7	703.2
Effect of exchange rate changes on cash and cash equivalents	(3.0)	2.5
Increase (Decrease) in Cash and Cash Equivalents	(6.1)	51.7
Cash and Cash Equivalents, beginning of period	58.9	6.7
Cash and Cash Equivalents, end of period	$ 52.8	$ 58.4
Noncash Investing and Financing Activities:		
Assets acquired by the assumption or incurrence of liabilities	$ 3.4	$ 19.5
Assets acquired/Liabilities settled by the issuance of units	$ 116.0	$ 15.0

The accompanying notes are an integral part of these consolidated financial statements.

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. Organization

General

Unless the context requires otherwise, references to “we,” “us,” “our” or the “Partnership” are intended to mean Kinder Morgan Energy Partners, L.P. and its consolidated subsidiaries. We have prepared our accompanying unaudited consolidated financial statements under the rules and regulations of the Securities and Exchange Commission. Under such rules and regulations, we have condensed or omitted certain information and notes normally included in financial statements prepared in conformity with accounting principles generally accepted in the United States of America.

We believe, however, that our disclosures are adequate to make the information presented not misleading. Our consolidated financial statements reflect normal adjustments, and also recurring adjustments that are, in the opinion of our management, necessary for a fair presentation of our financial results for the interim periods. You should read these consolidated financial statements in conjunction with our consolidated financial statements and related notes included in our Annual Report on Form 10-K for the year ended December 31, 2007, referred to in this report as our 2007 Form 10-K.

Knight Inc. (formerly known as Kinder Morgan, Inc.), Kinder Morgan G.P., Inc. and Kinder Morgan Management, LLC

Knight Inc., referred to as “Knight” in this report, is a private company owned by investors led by Richard D. Kinder, Chairman and Chief Executive Officer of Kinder Morgan G.P., Inc. (our general partner), and Kinder Morgan Management, LLC (our general partner’s delegate). Additional investors in Knight include, among others, certain members of Knight’s senior management, most of whom are also senior officers of our general partner and of its delegate. Before completing its going-private transaction on May 30, 2007, and subsequently being renamed, Knight was known as Kinder Morgan, Inc., a Kansas corporation referred to as “KMI” in this report.

Knight indirectly owns all the common stock of our general partner. On July 27, 2007, our general partner issued and sold 100,000 shares of Series A fixed-to-floating rate term cumulative preferred stock due 2057. The consent of holders of a majority of these preferred shares is required with respect to a commencement of or a filing of a voluntary bankruptcy proceeding with respect to us or two of our subsidiaries, SFPP, L.P. and Calnev Pipe Line LLC.

Kinder Morgan Management, LLC, referred to as “KMR” in this report, is a Delaware limited liability company. Our general partner owns all of KMR’s voting securities and, pursuant to a delegation of control agreement, has delegated to KMR, to the fullest extent permitted under Delaware law and our partnership agreement, all of its power and authority to manage and control our business and affairs, except that KMR cannot take certain specified actions without the approval of our general partner. More information on these entities and the delegation of control agreement is contained in our 2007 Form 10-K.

Basis of Presentation

Our consolidated financial statements include our accounts and those of our operating partnerships and their majority-owned and controlled subsidiaries. Our accounting records are maintained in United States dollars, and all references to dollars are United States dollars, except where stated otherwise. All significant intercompany items have been eliminated in consolidation. Certain amounts from prior periods have been reclassified to conform to the current presentation.

Our accompanying consolidated financial statements reflect amounts on a historical cost basis, and, accordingly, do not reflect any purchase accounting adjustments related to the May 30, 2007 going-private transaction of KMI, now known as Knight. In addition, as discussed in Note 2 below, our financial statements included in this report

include the transactions, balances and results of operations of our Trans Mountain pipeline system as if it had been transferred to us on January 1, 2006.

During the second quarter of 2008, we changed the date of our annual goodwill impairment test date to May 31 of each year. This change constitutes a change in the method of applying an accounting principle, as discussed in paragraph 4 of SFAS No. 154, “Accounting Changes and Error Corrections.” For more information on this change, see Note 6.

Also, prior to the third quarter of 2008, we reported five business segments: Products Pipelines; Natural Gas Pipelines; CO_2; Terminals; and Trans Mountain. As discussed in Note 2 below, we acquired (i) a one-third interest in the Express pipeline system; and (ii) the Jet Fuel pipeline system from Knight on August 28, 2008, and following the acquisition of these businesses, the operations of our Trans Mountain, Express and Jet Fuel pipeline systems have been combined to represent the “Kinder Morgan Canada” segment. For more information on our reportable business segments, see Note 11.

Net Income Per Unit

We compute Basic Limited Partners’ Net Income per Unit by dividing our limited partners’ interest in net income by the weighted average number of units outstanding during the period. Diluted Limited Partners’ Net Income per Unit reflects the maximum potential dilution that could occur if units whose issuance depends on the market price of the units at a future date were considered outstanding, or if, by application of the treasury stock method, options to issue units were exercised, both of which would result in the issuance of additional units that would then share in our net income.

Emerging Issues Task Force Issue No. 03-6, or EITF 03-6, “Participating Securities and the Two-Class Method Under FASB Statement No. 128” addresses the computation of earnings per share by entities that have issued securities other than common stock that contractually entitle the holder to participate in dividends and earnings of the entity when, and if, it declares dividends on its securities. In addition, effective January 1, 2009, we will begin calculating our Net Income per Unit according to the provisions of EITF 07-4, “Application of the Two-Class Method under FASB Statement No. 128, Earnings per Share, to Master Limited Partnerships.” EITF 07-4 provides guidance for how current period earnings should be allocated between limited partners and a general partner when the partnership agreement contains incentive distribution rights. For partnerships, under the two-class method, earnings per unit is calculated as if all of the earnings for the period were distributed regardless of whether a general partner has discretion over the amount of distribution to be made for any particular period. For more information regarding EITF 07-4, see Note 15.

2. Acquisitions, Joint Ventures and Divestitures

Acquisitions from Unrelated Entities

During the first nine months of 2008, we recorded purchase price adjustments related to two separate previously completed business acquisitions involving unrelated (third-party) entities, and we made a preliminary purchase price allocation related to a third business acquisition. These three acquisitions were accounted for as business combinations according to the provisions of Statement of Financial Accounting Standards No. 141, “Business Combinations.” SFAS No. 141 requires business combinations involving unrelated entities to be accounted for using the purchase method of accounting, which establishes a new basis of accounting for the purchased assets and liabilities—the acquirer records all the acquired assets and assumed liabilities at their estimated fair market values (not the acquired entity’s book values) as of the acquisition date.

Vancouver Wharves Terminal

On May 30, 2007, we purchased the Vancouver Wharves bulk marine terminal from British Columbia Railway Company, a crown corporation owned by the Province of British Columbia, for an aggregate consideration of $59.5 million, consisting of $38.8 million in cash and $20.7 million in assumed liabilities. The Vancouver Wharves facility is located on the north shore of the Port of Vancouver’s main harbor and includes five deep-sea vessel berths situated on a 139-acre site. The terminal assets include significant rail infrastructure, dry bulk and liquid storage, and material handling systems that allow the terminal to handle over 3.5 million tons of cargo annually. The acquisition both expanded and complemented our existing terminal operations, and all of the acquired assets are included in our Terminals business segment.

In the first half of 2008, we made our final purchase price adjustments to reflect final fair value of acquired assets and final expected value of assumed liabilities. Our adjustments increased “Property, Plant and Equipment, net” by $2.7 million, reduced working capital balances by $1.6 million, and increased long-term liabilities by $1.1 million. Based on our estimate of fair market values, we allocated $53.4 million of our combined purchase price to “Property, Plant and Equipment, net,” and $6.1 million to items included within “Current Assets.”

Marine Terminals, Inc. Assets

Effective September 1, 2007, we acquired certain bulk terminals assets from Marine Terminals, Inc. for an aggregate consideration of $102.1 million, consisting of $100.8 million in cash and assumed liabilities of $1.3 million. The acquired assets and operations are primarily involved in the handling and storage of steel and alloys. The operations consist of two separate facilities located in Blytheville, Arkansas, and individual terminal facilities located in Decatur, Alabama; Hertford, North Carolina; and Berkley, South Carolina. Combined, the five facilities handle approximately 13.5 million tons of alloys and steel products annually and also provide stevedoring and harbor services, scrap handling, and scrap processing services to customers in the steel and alloys industry. The acquisition both expanded and complemented our existing ferro alloy terminal operations and will provide customers further access to our growing national network of marine and rail terminals. All of the acquired assets are included in our Terminals business segment.

In the first nine months of 2008, we paid an additional $0.5 million for purchase price settlements, and we made purchase price adjustments to reflect final fair value of acquired assets and final expected value of assumed liabilities. Our 2008 adjustments primarily reflected changes in the allocation of the purchase cost to intangible assets acquired. Based on our estimate of fair market values, we allocated $60.8 million of our combined purchase price to “Property, Plant and Equipment, net;” $21.7 million to “Other intangibles, net;” $18.6 million to “Goodwill;” and $1.0 million to “Other current assets” and “Deferred charges and other assets.”

The allocation to “Other intangibles, net” included a $20.1 million amount representing the fair value of a service contract entered into with Nucor Corporation, a large domestic steel company with significant operations in the Southeast region of the United States. For valuation purposes, the service contract was determined to have a useful life of 20 years, and pursuant to the contract’s provisions, the acquired terminal facilities will continue to provide Nucor with handling, processing, harboring and warehousing services.

The allocation to “Goodwill,” which is expected to be deductible for tax purposes, was based on the fact that this acquisition both expanded and complemented our existing ferro alloy terminal operations and will provide Nucor and other customers further access to our growing national network of marine and rail terminals. We believe the acquired value of the assets, including all contributing intangible assets, exceeded the fair value of acquired identifiable net assets and liabilities—in the aggregate, these factors represented goodwill.

Wilmington, North Carolina Liquids Terminal

On August 15, 2008, we purchased certain terminal assets from Chemserve, Inc. for an aggregate consideration of $12.7 million, consisting of $11.8 million in cash and $0.9 million in assumed liabilities. The liquids terminal facility is located in Wilmington, North Carolina and stores petroleum products and chemicals. The terminal includes significant transportation infrastructure, and provides liquid and heated storage and custom tank blending capabilities for agricultural and chemical products. The acquisition both expanded and complemented our existing Mid-Atlantic region terminal operations, and all of the acquired assets are included in our Terminals business segment. In the third quarter of 2008, we made a preliminary allocation of our purchase price to reflect the fair value of assets acquired; however, we expect to make our final purchase price allocation in the fourth quarter of 2008, including a final allocation to “Goodwill”.

Pro Forma Information

Pro forma consolidated income statement information that gives effect to all of the acquisitions we have made and all of the joint ventures we have entered into since January 1, 2007 as if they had occurred as of January 1, 2007 is not presented because it would not be materially different from the information presented in our accompanying consolidated statements of income.

Acquisitions from Knight

According to the provisions of Emerging Issues Task Force Issue No. 04-5, "Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights," effective January 1, 2006, Knight (which indirectly owns all the common stock of our general partner) was deemed to have control over us and no longer accounted for its investment in us under the equity method of accounting. Instead, as of this date, Knight included our accounts, balances and results of operations in its consolidated financial statements and, as required by the provisions of SFAS No. 141, we accounted for each of the two separate acquisitions discussed below as transfers of net assets between entities under common control.

Trans Mountain Pipeline System

On April 30, 2007, we acquired the Trans Mountain pipeline system from Knight for $549.1 million in cash. The transaction was approved by the independent directors of both Knight and KMR following the receipt by such directors of separate fairness opinions from different investment banks. We paid $549 million of the purchase price on April 30, 2007, and we paid the remaining $0.1 million in July 2007.

In April 2008, as a result of finalizing certain "true-up" provisions in our acquisition agreement related to Trans Mountain pipeline expansion spending, we received a cash contribution of $23.4 million from Knight. Pursuant to the accounting provisions concerning transfers of net assets between entities under common control, and consistent with our treatment of cash payments made to Knight for Trans Mountain net assets in 2007, we accounted for this cash contribution as an adjustment to equity—primarily as an increase in "Partners' Capital" in our accompanying consolidated balance sheet. We also included this $23.4 million receipt as a cash inflow item from investing activities in our accompanying consolidated statement of cash flows.

The Trans Mountain pipeline system, which transports crude oil and refined products from Edmonton, Alberta, Canada to marketing terminals and refineries in British Columbia and the state of Washington, completed a pump station expansion in April 2007 that increased pipeline throughput capacity to approximately 260,000 barrels per day. An additional expansion that increased pipeline capacity by 25,000 barrels per day was completed and began service on May 1, 2008. We completed construction on a final 15,000 barrel per day expansion on October 30, 2008, and total pipeline capacity is now approximately 300,000 barrels per day.

In addition, because Trans Mountain's operations are managed separately, involve different products and marketing strategies, and produce discrete financial information that is separately evaluated internally by our management, we identified our Trans Mountain pipeline system as a separate reportable business segment prior to the third quarter of 2008. Following the acquisition of our interests in the Express and Jet Fuel pipeline systems on August 28, 2008, discussed following, we combined the operations of our Trans Mountain, Express and Jet Fuel pipeline systems to represent the "Kinder Morgan Canada" segment.

Express and Jet Fuel Pipeline Systems

Effective August 28, 2008, we acquired Knight's 33 1/3% ownership interest in the Express pipeline system. The pipeline system is a batch-mode, common-carrier, crude oil pipeline system consisting of both the Express Pipeline and the Platte Pipeline (collectively referred to in this report as the Express pipeline system). We also acquired Knight's full ownership of an approximately 25-mile jet fuel pipeline that serves the Vancouver International Airport, located in Vancouver, British Columbia, Canada (referred to in this report as the Jet Fuel pipeline system). As consideration for these assets, we paid to Knight approximately 2.0 million common units, valued at $116.0 million. The acquisition complemented our existing Canadian pipeline system (Trans Mountain), and all of the acquired assets (including an acquired cash balance of $7.4 million) are included in our Kinder Morgan Canada business segment.

The Express Pipeline is a 780-mile, 24-inch diameter pipeline that begins at the crude oil pipeline hub at Hardisty, Alberta and terminates at the Casper, Wyoming facilities of the Platte Pipeline, and includes related metering and storage facilities, including tanks and pump stations. It has a design capacity of approximately 280,000 barrels per day. The Platte Pipeline is a 926-mile, 20-inch diameter pipeline that runs from the crude oil pipeline hub at Casper, Wyoming to refineries and interconnecting pipelines in the Wood River, Illinois area, and includes related pumping and storage facilities, including tanks. The Platte Pipeline has a capacity of approximately 150,000 barrels per day when shipping heavy oil. We now operate the Express pipeline system, and we account for our 33 1/3% ownership in the system under the equity method of accounting. In addition to our 33 1/3% equity ownership, our investment in Express includes an investment in unsecured debenture bonds issued by Express Holdings U.S. L.P., the partnership that maintains ownership of the U.S. portion of the Express pipeline system. For more information on this long-term note receivable, see Note 13.

When accounting for transfers of net assets between entities under common control, the purchase cost provisions (as they relate to purchase business combinations involving unrelated entities) of SFAS No. 141 explicitly do not apply; instead the method of accounting prescribed by SFAS No. 141 for such net asset transfers is similar to the pooling-of-interests method of accounting. Under this method, the carrying amount of net assets recognized in the balance sheets of each combining entity are carried forward to the balance sheet of the combined entity, and no other assets or liabilities are recognized as a result of the combination (that is, no recognition is made for a purchase premium or discount representing any difference between the consideration paid and the book value of the net assets acquired).

Therefore, in each of these two business acquisitions from Knight, we recognized the assets and liabilities acquired at their carrying amounts (historical cost) in the accounts of Knight (the transferring entity) at the date of transfer. The accounting treatment for combinations of entities under common control is consistent with the concept of poolings as combinations of common shareholder (or unitholder) interests, as the carrying amount of the assets and liabilities transferred to us were carried forward to our balance sheet, and all of the acquired equity accounts were also carried forward intact initially, and subsequently adjusted due to differences between (i) the consideration we paid for the acquired net assets; and (ii) the book value (carrying value) of the acquired net assets.

In addition to requiring that assets and liabilities be carried forward at historical costs, SFAS No. 141 also prescribes that for transfers of net assets between entities under common control, all financial statements presented be combined as of the date of common control, and all financial statements and financial information presented for prior periods should be restated to furnish comparative information. However, based upon our management's consideration of all of the quantitative and qualitative aspects of the transfer of the interests in the Express and Jet Fuel pipeline system net assets from Knight to us, we determined that the presentation of combined financial statements which include the financial information of the Express and Jet Fuel pipeline systems would not be materially different from financial statements which did not include such information and accordingly, we elected not to include the financial information of the Express and Jet Fuel pipeline systems in our consolidated financial statements for any periods prior to the transfer date of August 28, 2008.

Our consolidated financial statements and all other financial information included in this report therefore, have been prepared assuming that:

- the transfer of the Trans Mountain pipeline system net assets from Knight to us had occurred at the date when both Trans Mountain and we met the accounting requirements for entities under common control (January 1, 2006); and
- the transfer of both the 33 1/3% interest in the Express pipeline system net assets and the Jet Fuel pipeline system net assets from Knight to us had occurred at the date of transfer (August 28, 2008).

Since our 2007 consolidated results of operations include Trans Mountain's results of operations, we have included Knight's recognition of a $377.1 million goodwill impairment of Trans Mountain recorded in the first quarter of 2007 in our results of operations. We reported this expense separately as "Goodwill impairment expense" in our accompanying consolidated statement of income for the nine months ended September 30, 2007. For more information on this impairment expense, see Note 6.

Joint Ventures

Rockies Express Pipeline LLC

In the first nine months of 2008, we made capital contributions of $306.0 million to West2East Pipeline LLC (the sole owner of Rockies Express Pipeline LLC) to partially fund its Rockies Express Pipeline construction costs. We included this cash contribution as an increase to "Investments" in our accompanying consolidated balance sheet as of September 30, 2008, and we included it within "Contributions to equity investments" in our accompanying consolidated statement of cash flows for the nine months ended September 30, 2008. We own a 51% equity interest in West2East Pipeline LLC.

On June 24, 2008, Rockies Express completed a private offering of an aggregate of $1.3 billion in principal amount of fixed rate senior notes. Rockies Express received net proceeds of approximately $1.29 billion from this offering, after deducting the initial purchasers' discount and estimated offering expenses, and virtually all of the net proceeds from the sale of the notes were used to repay short-term commercial paper borrowings.

All payments of principal and interest in respect of these senior notes are the sole obligation of Rockies Express. Noteholders will have no recourse against us, Sempra Energy or ConocoPhillips (the two other member owners of West2East Pipeline LLC), or against any of our or their respective officers, directors, employees, shareholders, members, managers, unitholders or affiliates for any failure by Rockies Express to perform or comply with its obligations pursuant to the notes or the indenture.

Midcontinent Express Pipeline LLC

In the first nine months of 2008, we made capital contributions of $27.5 million to Midcontinent Express Pipeline LLC to partially fund its Midcontinent Express Pipeline construction costs. We included this cash contribution as an increase to "Investments" in our accompanying consolidated balance sheet as of September 30, 2008, and we included it within "Contributions to equity investments" in our accompanying consolidated statement of cash flows for the nine months ended September 30, 2008. We own a 50% equity interest in West2East Pipeline LLC.

We also received, in the first nine months of 2008, an $89.1 million return of capital from Midcontinent Express Pipeline LLC. In February 2008, Midcontinent entered into and then made borrowings under a new $1.4 billion three-year, unsecured revolving credit facility due February 28, 2011. Midcontinent then made distributions (in excess of cumulative earnings) to its two member owners to reimburse them for prior contributions made to fund its pipeline construction costs, and we reflected this cash receipt separately within the investing section of our accompanying consolidated statement of cash flows.

Fayetteville Express Pipeline LLC

On October 1, 2008, we announced that we have entered into a 50/50 joint venture with Energy Transfer Partners, L.P. to build and develop the Fayetteville Express Pipeline, a new natural gas pipeline that will provide shippers in the Arkansas Fayetteville Shale area with takeaway natural gas capacity, added flexibility, and further access to growing markets. Fayetteville Express Pipeline LLC will construct the approximately 185-mile pipeline, which will originate in Conway County, Arkansas, continue eastward through White County, Arkansas, and terminate at an interconnect with Trunkline Gas Company's pipeline in Quitman County, Mississippi. The new pipeline will also interconnect with Natural Gas Pipeline Company of America LLC's pipeline in White County, Arkansas; Texas Gas Transmission LLC's pipeline in Coahoma County, Mississippi; and ANR Pipeline Company's pipeline in Quitman County, Mississippi. Natural Gas Pipeline Company of America's pipeline is operated and 20% owned by Knight.

The Fayetteville Express Pipeline will have an initial capacity of 2.0 billion cubic feet of natural gas per day. Pending necessary regulatory approvals, the approximately $1.3 billion pipeline project is expected to be in service by late 2010 or early 2011. Fayetteville Express Pipeline LLC has secured binding 10-year commitments totaling approximately 1.85 billion cubic feet per day, and in order to gauge further shipper interest, it is conducting a binding open season from October 8 through November 7, 2008. Depending on shipper support during the open season, capacity on the proposed pipeline may be increased.

Divestitures

North System Natural Gas Liquids Pipeline System – Discontinued Operations

On July 2, 2007, we announced that we entered into an agreement to sell the North System natural gas liquids pipeline and our 50% ownership interest in the Heartland Pipeline Company (collectively referred to in this report as our North System) to ONEOK Partners, L.P. for approximately $298.6 million in cash. Our investment in net assets, including all transaction related accruals, was approximately $145.8 million, most of which represented property, plant and equipment, and we recognized approximately $152.8 million of gain in the fourth quarter of 2007 from the sale of these net assets. In the first half of 2008, following final account and inventory reconciliations, we paid a net amount of $2.4 million to ONEOK to fully settle the sale of (i) working capital items;

(ii) total physical product liquids inventory and inventory obligations for certain liquids products; and (iii) the allocation of pre-acquisition investee distributions. Based primarily upon these adjustments, which were below the amounts reserved, we recognized an additional gain of $1.3 million in the first nine months of 2008, and we reported this gain separately as “Adjustment to gain on disposal of North System” within the discontinued operations section of our accompanying consolidated statement of income for the nine months ended September 30, 2008.

The North System consists of an approximately 1,600-mile interstate common carrier pipeline system that delivers natural gas liquids and refined petroleum products from south central Kansas to the Chicago area. Also included in the sale were eight propane truck-loading terminals, located at various points in three states along the pipeline system, and one multi-product terminal complex located in Morris, Illinois. Prior to the sale, all of the assets were included in our Products Pipelines business segment.

In accordance with SFAS No. 144, “Accounting for the Impairment or Disposal of Long-Lived Assets,” we accounted for the North System business as a discontinued operation whereby the financial results and the gains on disposal of the North System have been reclassified to discontinued operations in our accompanying consolidated statements of income. Summarized financial information of the North System is as follows (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	**2007**	**2008**	**2007**
Operating revenues	$ —	$ 14.4	$ —	$ 41.1
Operating expenses	—	(4.1)	—	(14.8)
Depreciation and amortization	—	(2.3)	—	(7.0)
Earnings from equity investments	—	0.6	—	1.8
Income from operations	—	8.6	—	21.1
Gain on disposal	—	—	1.3	—
Earnings from Discontinued Operations	$ —	$ 8.6	$ 1.3	$ 21.1

Additionally, in our accompanying consolidated statement of cash flows for the nine months ended September 30, 2007, we elected not to present separately the North System’s operating and investing cash flows as discontinued operations, and, because the sale of the North System does not change the structure of our internal organization in a manner that causes a change to our reportable business segments pursuant to the provisions of SFAS No. 131, “Disclosures about Segments of an Enterprise and Related Information,” we have included the North System’s financial results within our Products Pipelines business segment disclosures presented in this report for the three and nine months ended September 30, 2007.

Thunder Creek Gas Services, LLC

Effective April 1, 2008, we sold our 25% ownership interest in Thunder Creek Gas Services, LLC to PVR Midstream LLC, a subsidiary of Penn Virginia Corporation. Prior to the sale, we accounted for our investment in Thunder Creek Gas Services, LLC, referred to in this report as Thunder Creek, under the equity method of accounting and included its financial results within our Natural Gas Pipelines business segment. In the second quarter of 2008, we received cash proceeds, net of closing costs and settlements, of approximately $50.7 million for our investment, and we recognized a gain of $13.0 million with respect to this transaction. We used the proceeds from this sale to reduce the outstanding balance on our commercial paper borrowings, and we included the amount of the gain within the caption “Other, net” in our accompanying consolidated statement of income for the nine months ended September 30, 2008.

Thunder Creek provides natural gas gathering, compression and treating service to a number of coal seam gas producers in the Powder River Basin of northeast Wyoming. Thunder Creek’s operations are a combination of mainline and low pressure gathering assets, and throughput volumes include both coal seam and conventional plant residue gas. The mainline assets include 125 miles of mainline pipeline, 230 miles of high and low pressure laterals, approximately 26,600 horsepower of mainline compression, and carbon dioxide removal facilities consisting of a 220 million cubic feet per day carbon dioxide treating plant with natural gas dehydration capability. Devon Energy owns the remaining 75% ownership interest.

3. Litigation, Environmental and Other Contingencies

Below is a brief description of our ongoing material legal proceedings, including any material developments that occurred in such proceedings during the three months ended September 30, 2008. Additional information with respect to these proceedings can be found in Note 16 to our audited financial statements that were filed with our 2007 Form 10-K and in our subsequently filed quarterly reports on Form 10-Q. This Note also contains a description of any material legal proceedings that were initiated against us during the three months ended September 30, 2008.

Federal Energy Regulatory Commission Proceedings

Our SFPP, L.P. and Calnev Pipe Line LLC subsidiaries are involved in various proceedings before the Federal Energy Regulatory Commission, referred to in this note as the FERC. The tariffs and rates charged by SFPP and Calnev are subject to numerous ongoing proceedings at the FERC, including shippers' complaints and protests regarding interstate rates on these pipeline systems. In general, these complaints allege the rates and tariffs charged by SFPP and Calnev are not just and reasonable.

As to SFPP, the issues involved in these proceedings include, among others: (i) whether certain of our Pacific operations' rates are "grandfathered" under the Energy Policy Act of 1992, referred to in this note as EPAct 1992, and therefore deemed to be just and reasonable; (ii) whether "substantially changed circumstances" have occurred with respect to any grandfathered rates such that those rates could be challenged; (iii) whether indexed rate increases may become effective without investigation; (iv) the capital structure to be used in computing the "starting rate base" of our Pacific operations; (v) the level of income tax allowance we may include in our rates; and (vi) the recovery of civil and regulatory litigation expenses and certain pipeline reconditioning and environmental costs incurred by our Pacific operations.

In May 2005, the FERC issued a statement of general policy stating it will permit pipelines to include in cost of service a tax allowance to reflect actual or potential tax liability on their public utility income attributable to all partnership or limited liability company interests, if the ultimate owner of the interest has an actual or potential income tax liability on such income. Whether a pipeline's owners have such actual or potential income tax liability will be reviewed by the FERC on a case-by-case basis. Although the revised policy is generally favorable for pipelines that are organized as tax pass-through entities, it still entails rate risk due to the case-by-case review requirement.

In this note, we refer to SFPP, L.P. as SFPP; Calnev Pipe Line LLC as Calnev; Chevron Products Company as Chevron; Navajo Refining Company, L.P. as Navajo; ARCO Products Company as ARCO; BP West Coast Products, LLC as BP WCP; Texaco Refining and Marketing Inc. as Texaco; Western Refining Company, L.P. as Western Refining; Mobil Oil Corporation as Mobil; ExxonMobil Oil Corporation as ExxonMobil; Tosco Corporation as Tosco; ConocoPhillips Company as ConocoPhillips; Ultramar Diamond Shamrock Corporation/Ultramar Inc. as Ultramar; Valero Energy Corporation as Valero; Valero Marketing and Supply Company as Valero Marketing; and America West Airlines, Inc., Continental Airlines, Inc., Northwest Airlines, Inc., Southwest Airlines Co. and US Airways, Inc., collectively, as the Airline Complainants.

Following are a summary of developments during the third quarter of 2008 and a listing of certain active FERC proceedings pertaining to our Pacific operations:

- FERC Docket No. OR92-8, *et al.*—Complainants/Protestants: Chevron; Navajo; ARCO; BP WCP; Western Refining; ExxonMobil; Tosco; and Texaco (Ultramar is an intervenor)—Defendant: SFPP Consolidated proceeding involving shipper complaints against certain East Line and West Line rates. All six issues (and others) described above are involved in these proceedings. Portions of this proceeding were appealed (and re-appealed) to the United States Court of Appeals for the District of Columbia Circuit, referred to in this note as the D.C. Court, and remanded to the FERC. Portions of this proceeding are currently being held in abeyance by the D.C. Court pending completion of agency proceedings. BP WCP, Chevron, and ExxonMobil requested a hearing before the FERC on remanded grandfathering and income tax allowance issues. The FERC issued an Order on Rehearing, Remand, Compliance, and Tariff Filings on December 26, 2007, which denied the requests for a hearing, and ruled on SFPP's March 7, 2006 compliance filing and remand issues. The

FERC, *inter alia*, affirmed its income tax allowance policy, further clarified the implementation of that policy with respect to SFPP, and required SFPP to file a compliance filing. On February 15, 2008, the FERC issued an order granting and denying rehearing regarding certain findings in the December 2007 order;

- FERC Docket No. OR92-8-025—Complainants/Protestants: BP WCP; ExxonMobil; Chevron; ConocoPhillips; and Ultramar—Defendant: SFPP
  Proceeding involving shipper complaints against rates charged prior to April 1, 1999 at SFPP's Watson Station drain-dry facilities. A settlement reserved the issue of whether reparations were owed for the period prior to April 1, 1999. On February 12, 2008, the FERC ruled that SFPP owed reparations for shipments prior to April 1, 1999, and in March 2008, SFPP made required reparation payments of $23.3 million. SFPP filed a petition for review of the February 12, 2008 order at the D.C. Court, and the case is now being briefed;

- FERC Docket No. OR96-2, *et al.*—Complainants/Protestants: All Shippers except Chevron (which is an intervenor)—Defendant: SFPP
  Consolidated proceeding involving shipper complaints against all SFPP rates. All six issues (and others) described above are involved in these proceedings. Portions of this proceeding were appealed (and re-appealed) to the D.C. Court and remanded to the FERC. Portions of this proceeding are currently being held in abeyance by the D.C. Court pending completion of agency proceedings. The FERC issued an Order on Rehearing, Remand, Compliance, and Tariff Filings on December 26, 2007, which denied the requests for a hearing and ruled on SFPP's March 7, 2006 compliance filing and remand issues. The FERC, *inter alia*, affirmed its income tax allowance policy and further clarified the implementation of that policy with respect to SFPP, and required SFPP to file a compliance filing. On February 15, 2008, the FERC issued an order granting and denying rehearing regarding certain findings in the December 2007 order. On May 2, 2008, the FERC issued an order reopening the record for a paper hearing on issues related to rate of return on equity applicable to the Sepulveda Line service in light of the FERC's policy statement issued in April of 2008 regarding the methodology for determining returns on equity. The parties have filed a settlement regarding the sole issue of the numeric value of the rate of return on equity to be applied in this proceeding with respect to the Sepulveda Line service that, upon approval by the FERC, would obviate the need for the paper hearing;

- FERC Docket Nos. OR02-4 and OR03-5—Complainant/Protestant: Chevron—Defendant: SFPP
  Chevron initiated proceeding to permit Chevron to become complainant in OR96-2. Appealed to the D.C. Court and held in abeyance pending final disposition of the OR96-2 proceedings;

- FERC Docket No. OR04-3—Complainants/Protestants: America West Airlines; Southwest Airlines; Northwest Airlines; and Continental Airlines—Defendant: SFPP
  Complaint alleges that West Line and Watson Station rates are unjust and unreasonable. Unsettled Watson Station issues severed and consolidated into a proceeding focused only on Watson-related issues which has now been settled (see above under FERC Docket No. OR92-8-025). The FERC has set the complaints against the West Line rates for hearing (see below under FERC Docket Nos. OR03-5-000, OR05-4, and OR05-5);

- FERC Docket Nos. OR03-5, OR05-4 and OR05-5—Complainants/Protestants: BP WCP; ExxonMobil; and ConocoPhillips (other shippers intervened)—Defendant: SFPP
  Complaints allege that SFPP's interstate rates are not just and reasonable. The portion of the complaints challenging SFPP's West Line and East Line rates (OR03-5-000) is scheduled for hearing in November of 2008. A hearing was held in May of 2008 regarding the portion of the complaints challenging SFPP's North Line and Oregon Line rates (see below under FERC Docket No. OR03-5-001);

- FERC Docket No. OR03-5-001—Complainants/Protestants: BP WCP; ExxonMobil; and ConocoPhillips (other shippers intervened)—Defendant: SFPP
  The FERC severed the portions of the complaints in Docket Nos. OR03-5, OR05-4, and OR05-5 regarding SFPP's North and Oregon Line rates into a separate proceeding in Docket No. OR03-5-001. A hearing was held in May 2008 and an initial decision is expected in December of 2008;

- FERC Docket No. OR07-1—Complainant/Protestant: Tesoro—Defendant: SFPP
  Complaint alleges that SFPP's North Line rates are not just and reasonable. The FERC is holding the complaint in abeyance pending resolution at the D.C. Court of, among other things, income tax allowance and grandfathering issues. The D.C. Court issued an opinion on these issues on May 29, 2007, upholding the FERC's income tax allowance policy;

- FERC Docket No. OR07-2—Complainant/Protestant: Tesoro—Defendant: SFPP
  Complaint alleges that SFPP's West Line rates are not just and reasonable. The FERC is holding the complaint in abeyance pending resolution at the D.C. Court of, among other things, income tax allowance and grandfathering issues. The D.C. Court issued an opinion on these issues on May 29, 2007, upholding the FERC's income tax allowance policy. A request that the FERC set the complaint for hearing – which SFPP opposed – is pending before the FERC;

- FERC Docket No. OR07-3—Complainants/Protestants: BP WCP; Chevron; ExxonMobil; Tesoro; and Valero Marketing—Defendant: SFPP
  Complaint alleges that SFPP's North Line indexed rate increase was not just and reasonable. The FERC dismissed the complaint and denied rehearing. Petitions for review were filed by BP WCP and ExxonMobil at the D.C. Court. This proceeding is currently in abeyance pending a decision by the D.C. Court in the Tesoro review proceeding related to Docket No. OR07-16.

- FERC Docket No. OR07-4—Complainants/Protestants: BP WCP; Chevron; and ExxonMobil—Defendants: SFPP; Kinder Morgan G.P., Inc.; and Knight Inc.
  Complaint alleges that SFPP's rates are not just and reasonable. The FERC is holding the complaint in abeyance pending resolution at the D.C. Court of, among other things, income tax allowance and grandfathering issues. The D.C. Court issued an opinion on these issues on May 29, 2007, upholding the FERC's income tax allowance policy. Complainants have withdrawn the portions of the complaint directed to SFPP's affiliates;

- FERC Docket Nos. OR07-5 and OR07-7 (consolidated)—Complainants/Protestants: ExxonMobil and Tesoro—Defendants: Calnev; Kinder Morgan G.P., Inc.; and Knight Inc.
  Complaints allege that none of Calnev's current rates are just or reasonable. On July 19, 2007, the FERC accepted and held in abeyance the portion of the complaints against the non-grandfathered portion of Calnev's rates, dismissed with prejudice the complaints against Calnev's affiliates, and allowed complainants to file amended complaints regarding the grandfathered portion of Calnev's rates. Pursuant to a settlement, ExxonMobil filed a notice in April of 2008 withdrawing its complaint in Docket No. OR07-5 and its motion to intervene in Docket No. OR07-7. Tesoro's complaint in Docket No. OR07-7 is still pending before the FERC;

- FERC Docket No. OR07-6—Complainant/Protestant: ConocoPhillips—Defendant: SFPP
  Complaint alleges that SFPP's North Line indexed rate increase was not just and reasonable. The FERC dismissed the complaints in Docket Nos. OR07-3 and OR07-6 in a single order, without consolidating the complaints, and denied the request for rehearing of the dismissal filed in Docket No. OR07-3. Although the FERC orders in these dockets have been appealed by certain of the complainants in Docket No. OR07-3, they were not appealed by ConocoPhillips in Docket No. OR07-6. The FERC's decision in Docket No. OR07-6 is now final;

- FERC Docket Nos. OR07-8 and OR07-11 (consolidated)—Complainants/Protestants: BP WCP and ExxonMobil —Defendant: SFPP
  Complaints allege that SFPP's 2005 indexed rate increase was not just and reasonable. Although the FERC dismissed challenges to SFPP's underlying rate, the FERC declined to dismiss the portion of the OR07-8 Complaint addressing SFPP's July 1, 2005 index-based rate increases. A settlement has been certified to the FERC, and FERC action on the settlement is pending;

- FERC Docket No. OR07-9—Complainant/Protestant: BP WCP—Defendant: SFPP
  Complaint alleges that SFPP's ultra low sulphur diesel (ULSD) recovery fee violates the filed rate doctrine and that, in any event, the recovery fee is unjust and unreasonable. Following dismissal of the complaint by FERC, BP WCP filed a petition for review which the D.C. Court dismissed in March of 2008;

- FERC Docket No. OR07-14—Complainants/Protestants: BP WCP and Chevron—Defendants: SFPP; Calnev, and several affiliates
  Complaint alleges violations of the Interstate Commerce Act and FERC's cash management regulations, seeks review of the FERC Form 6 annual reports of SFPP and Calnev, and again requests interim refunds and reparations. The FERC dismissed the complaints, but directed SFPP and Calnev to review their cash management agreements and records to confirm compliance with FERC requirements and to make corrections, if necessary. Cash management agreements have been filed in compliance with the FERC's directive;

- FERC Docket No. OR07-16—Complainant/Protestant: Tesoro—Defendant: Calnev
  Complaint challenges Calnev's 2005, 2006, and 2007 indexing adjustments. The FERC dismissed the complaint. A petition for review was filed at the D.C. Court by Tesoro, briefing is complete, and oral argument is scheduled for November 18, 2008;

- FERC Docket No. OR07-18—Complainants/Protestants: Airline Complainants; Chevron; and Valero Marketing—Defendant: Calnev
  Complaint alleges that Calnev's rates are unjust and unreasonable and that none of Calnev's rates are grandfathered under EPAct 1992. In December 2007, the FERC issued an order accepting and holding in abeyance the portion of the complaint against the non-grandfathered portion of Calnev's rates. Pursuant to a FERC order, an amended complaint regarding the grandfathering issue has been filed. The FERC has not acted on the amended complaint;

- FERC Docket No. OR07-19—Complainant/Protestant: ConocoPhillips—Defendant: Calnev
  Complaint alleges that Calnev's rates are unjust and unreasonable and that none of Calnev's rates are grandfathered under EPAct 1992. In December 2007, the FERC issued an order accepting and holding in abeyance the portion of the complaint against the non-grandfathered portion of Calnev's rates. Pursuant to a FERC order, an amended complaint regarding the grandfathering issue has been filed. The FERC has not acted on the amended complaint;

- FERC Docket No. OR07-20—Complainant/Protestant: BP WCP—Defendant: SFPP
  Complaint alleges that SFPP's 2007 indexed rate increase was not just and reasonable. The FERC dismissed the complaint and complainant filed a request for rehearing. Prior to a FERC ruling on the request for rehearing, the parties reached a settlement. In February 2008, FERC accepted a joint offer of settlement that dismissed, with prejudice, the East Line index rate portion of the complaint in OR07-20 for the period from June 1, 2006 through and to November 30, 2007. Petition for review was filed by BP WCP at the D.C. Court. This proceeding is currently in abeyance pending a decision by the D.C. Court in the Tesoro review proceeding related to Docket No. OR07-16;

- FERC Docket No. OR07-22—Complainant/Protestant: BP WCP—Defendant: Calnev
  Complaint alleges that Calnev's rates are unjust and unreasonable and that none of Calnev's rates are grandfathered under EPAct 1992. Pursuant to a FERC order, an amended complaint regarding the grandfathering issue has been filed, but the FERC has not acted on the amended complaint;

- FERC Docket No. OR08-13—Complainants/Protestants: BP WCP and ExxonMobil—Defendant: SFPP
  Complaint alleges that all of SFPP's rates are unjust and unreasonable. SFPP filed an answer on August 28, 2008. The FERC has not acted on the complaint. A settlement has been filed with the FERC with respect to the East Line portion of this complaint, and FERC action on the settlement is pending;

- FERC Docket No. OR08-15—Complainants/Protestants: BP WCP and ExxonMobil—Defendant: SFPP
  Complaint challenges SFPP's indexing adjustments that went into effect on July 1, 2008. SFPP filed an answer

on September 8, 2008. The FERC has not acted on the complaint. A settlement has been filed with the FERC with respect to the East Line portion of this complaint, and FERC action on the settlement is pending;

- FERC Docket No. IS05-230 (North Line rate case)—Complainants/Protestants: Shippers—Defendant: SFPP
  SFPP filed to increase North Line rates to reflect increased costs due to installation of new pipe between Concord and Sacramento, California. Various shippers protested. Administrative law judge's decision is pending before the FERC on exceptions. On August 31, 2007, BP WCP and ExxonMobil filed a motion to reopen the record on the issue of SFPP's appropriate rate of return on equity, which SFPP answered on September 18, 2007. On May 2, 2008, the FERC issued an order reopening the record in Docket No. IS05-230 for a paper hearing on issues related to rate of return on equity in light of the FERC's policy statement issued in April of 2008 regarding the methodology for determining returns on equity. The parties have filed a settlement regarding the sole issue of the numeric value of the rate of return on equity to be applied in this proceeding that, upon approval by the FERC, would obviate the need for the paper hearing;

- FERC Docket No. IS05-327—Complainants/Protestants: Shippers—Defendant: SFPP
  SFPP filed to increase certain rates on its pipelines pursuant to FERC's indexing methodology. Various shippers protested, but the FERC determined that the tariff filings were consistent with its regulations. The FERC denied rehearing. The D.C. Court dismissed a petition for review, citing a lack of jurisdiction to review a decision by FERC not to order an investigation;

- FERC Docket No. IS06-283 (East Line rate case)—Complainants/Protestants: Shippers—Defendant: SFPP
  SFPP filed to increase East Line rates to reflect increased costs due to installation of new pipe between El Paso, Texas and Tucson, Arizona. Various shippers protested. This proceeding has been resolved by a settlement that has been approved by the FERC. SFPP made the payments to the parties to the settlement on April 8, 2008 and certified to the FERC that such payments were made on April 9, 2008;

- FERC Docket No. IS06-296—Complainant/Protestant: ExxonMobil—Defendant: Calnev
  Calnev increased its interstate rates pursuant to the FERC's indexing methodology. ExxonMobil protested the indexing adjustment. This proceeding has been resolved by a settlement. On April 18, 2008, ExxonMobil filed a notice withdrawing its protest in Docket No. IS06-296;

- FERC Docket No. IS06-356—Complainants/Protestants: Shippers—Defendant: SFPP
  SFPP filed to increase certain rates on its pipelines pursuant to FERC's indexing methodology. Various shippers protested. The FERC generally found the tariff filings consistent with its regulations but rescinded the index increase for the East Line rates. SFPP requested rehearing regarding the FERC's decision as to the East Line rates, which the FERC denied. In February 2008, the FERC accepted a joint offer of settlement which, among other things, resolved all protests and complaints related to the East Line 2006 indexing adjustment. SFPP made the payments to the parties to the settlement on April 8, 2008;

- FERC Docket No. IS07-137 (Ultra Low Sulfur Diesel (ULSD) surcharge)—Complainants/Protestants: Shippers—Defendant: SFPP
  SFPP filed tariffs reflecting a ULSD recovery fee on diesel products and a ULSD litigation surcharge, and various shippers protested the tariffs. The FERC accepted, subject to refund, the ULSD recovery fee and rejected the ULSD litigation surcharge. Chevron and Tesoro filed requests for rehearing, which the FERC denied by operation of law. BP WCP petitioned the D.C. Court for review of the FERC's denial, the FERC filed a motion to dismiss, and the D.C. Court granted the FERC's motion. In May 2008, the FERC set this proceeding for hearing and initiated settlement proceedings which have resulted in a settlement in principle between the parties;

- FERC Docket No. IS07-229—Complainants/Protestants: BP WCP and ExxonMobil—Defendant: SFPP
  SFPP filed to increase certain rates on its pipelines pursuant to the FERC's indexing methodology. Two shippers filed protests. The FERC found the tariff filings consistent with its regulations but suspended the increased rates subject to refund pending challenges to SFPP's underlying rates. In February 2008, the FERC accepted a joint offer of settlement which, among other things, resolved all protests and complaints related to the East Line 2007 indexing adjustments. In April 2008, SFPP certified payments under the settlement agreement;

- FERC Docket No. IS07-234—Complainants/Protestants: BP WCP and ExxonMobil—Defendant: Calnev
  Calnev filed to increase certain rates on its pipeline pursuant to FERC's indexing methodology. Two shippers protested. The FERC found the tariff filings consistent with its regulations but suspended the increased rates subject to refund pending challenges to SFPP's underlying rates. Calnev and ExxonMobil reached an agreement to settle this and other dockets. On April 18, 2008, ExxonMobil filed a notice withdrawing its protest in Docket No. IS07-234;

- FERC Docket No. IS08-28—Complainants/Protestants: ConocoPhillips; Chevron; BP WCP; ExxonMobil; Southwest Airlines; Western; and Valero—Defendant: SFPP
  SFPP filed to increase its East Line rates based on costs incurred related to an expansion. Various shippers filed protests. Docket No. IS08-389 has been consolidated with this proceeding. A settlement in principle has been reached. A settlement has been filed with the FERC, and FERC action on the settlement is pending;

- FERC Docket No. IS08-302—Complainants/Protestants: Chevron; BP WCP; ExxonMobil; and Tesoro—Defendant: SFPP
  SFPP filed to increase certain rates on its pipelines pursuant to FERC's indexing methodology. Certain shippers protested. The FERC found the tariff filings consistent with its regulations but suspended the increased rates subject to refund (except for the Oregon Line rate) pending challenges to SFPP's underlying rates;

- FERC Docket No. IS08-389—Complainants/Protestants: ConocoPhillips, Valero, Southwest Airlines Co., Navajo, Western—Defendant: SFPP
  SFPP filed to decrease rates on its East Line. In July of 2008, various shippers protested, claiming that the rates should have been further decreased. On July 29, 2008, the FERC accepted and suspended the tariff, subject to refund, to become effective August 1, 2008, consolidated the proceeding with Docket No. IS08-28, and held in abeyance further action pending the outcome of settlement negotiations. A settlement in principle has been reached. A settlement has been filed with the FERC, and FERC action on the settlement is pending;

- FERC Docket No. IS08-390—Complainants/Protestants: BP WCP, ExxonMobil, ConocoPhillips, Valero, Chevron, the Airlines—Defendant: SFPP
  SFPP filed to increase rates on its West Line. In July of 2008, various shippers protested, claiming that the rates are unjust and unreasonable. On July 29, 2008, the FERC suspended the tariffs, to become effective August 1, 2008, subject to refund. A procedural schedule is in place and discovery is ongoing. A hearing is scheduled for June of 2009; and

- Motions to compel payment of interim damages (various dockets)—Complainants/Protestants: Shippers—Defendants: SFPP; Kinder Morgan G.P., Inc.; and Knight Inc.
  Motions seek payment of interim refunds or escrow of funds pending resolution of various complaints and protests involving SFPP. The FERC denied shippers' refund requests in an order issued on December 26, 2007 in Docket Nos. OR92-8, *et al*. On March 19, 2008, ConocoPhillips and Tosco filed a Motion for Interim Refund and Reparations Order. SFPP filed a response on April 3, 2008. The FERC has yet to act on the parties' motion.

In December 2005, SFPP received a FERC order in Docket Nos. OR92-8, *et al*. and OR96-2, *et al*. that directed it to submit compliance filings and revised tariffs. In accordance with the FERC's December 2005 order and its February 2006 order on rehearing, SFPP submitted a compliance filing to the FERC in March 2006, and rate reductions were implemented on May 1, 2006.

In December 2007, as a follow-up to the March 2006 compliance filing, SFPP received a FERC order that directed it to submit revised compliance filings and revised tariffs. In conjunction with this order, our other FERC and California Public Utilities Commission rate cases, and other unrelated litigation matters, we increased our litigation reserves by $140.0 million in the fourth quarter of 2007. We assume that, with respect to our SFPP litigation reserves, any reparations and accrued interest thereon will be paid no earlier than the first quarter of 2009. In accordance with FERC's December 2007 order and its February 2008 order on rehearing, SFPP submitted a compliance filing to FERC in February 2008, and further rate reductions were implemented on March 1, 2008. We estimate that the impact of the new rates on our 2008 budget will be less than $3.0 million.

In the second quarter of 2008, SFPP and Calnev made combined settlement payments to various shippers totaling approximately $6.9 million and in general, if the shippers are successful in proving their claims, they are entitled to reparations or refunds of any excess tariffs or rates paid during the two year period prior to the filing of their complaint, and SFPP and Calnev may be required to reduce the amount of their tariffs or rates for particular services. These proceedings tend to be protracted, with decisions of the FERC often appealed to the federal courts. Based on our review of these FERC proceedings, we estimate that as of September 30, 2008, shippers are seeking approximately $267 million in reparation and refund payments and approximately $45 million in additional annual rate reductions.

California Public Utilities Commission Proceedings

On April 7, 1997, ARCO, Mobil and Texaco filed a complaint against SFPP with the California Public Utilities Commission, referred to in this note as the CPUC. The complaint challenges rates charged by SFPP for intrastate transportation of refined petroleum products through its pipeline system in the state of California and requests prospective rate adjustments and refunds with respect to previously untariffed charges for certain pipeline transportation and related services.

In October 2002, the CPUC issued a resolution, referred to in this note as the Power Surcharge Resolution, approving a 2001 request by SFPP to raise its California rates to reflect increased power costs. The resolution approving the requested rate increase also required SFPP to submit cost data for 2001, 2002, and 2003, and to assist the CPUC in determining whether SFPP's overall rates for California intrastate transportation services are reasonable. The resolution reserves the right to require refunds, from the date of issuance of the resolution, to the extent the CPUC's analysis of cost data to be submitted by SFPP demonstrates that SFPP's California jurisdictional rates are unreasonable in any fashion.

On December 26, 2006, Tesoro filed a complaint challenging the reasonableness of SFPP's intrastate rates for the three-year period from December 2003 through December 2006 and requesting approximately $8 million in reparations. As a result of previous SFPP rate filings and related protests, the rates that are the subject of the Tesoro complaint are being collected subject to refund.

SFPP also has various, pending ratemaking matters before the CPUC that are unrelated to the above-referenced complaints and the Power Surcharge Resolution. Protests to these rate increase applications have been filed by various shippers. As a consequence of the protests, the related rate increases are being collected subject to refund.

All of the above matters have been consolidated and assigned to a single administrative law judge. At the time of this report, it is unknown when a decision from the CPUC regarding the CPUC complaints and the Power Surcharge Resolution will be received. No schedule has been established for hearing and resolution of the consolidated proceedings other than the 1997 CPUC complaint and the Power Surcharge Resolution. Based on our review of these CPUC proceedings, we estimate that shippers are seeking approximately $100 million in reparation and refund payments and approximately $35 million in annual rate reductions.

On June 6, 2008, as required by CPUC order, SFPP and Calnev Pipe Line Company filed separate general rate case applications, neither of which request a change in existing pipeline rates and both of which assert that existing pipeline rates are reasonable. On September 26, 2008, SFPP filed an amendment to its general rate case application, requesting CPUC approval of a $5 million rate increase for intrastate transportation services to become effective November 1, 2008. No action has been taken by the CPUC with respect to either the SFPP amended general rate case filing or the Calnev general rate case filing.

Carbon Dioxide Litigation

Shores and First State Bank of Denton Lawsuits

Kinder Morgan CO_2 Company, L.P. (referred to in this note as Kinder Morgan CO_2), Kinder Morgan G.P., Inc., and Cortez Pipeline Company were among the named defendants in Shores, et al. v. Mobil Oil Corp., et al., No. GC-99-01184 (Statutory Probate Court, Denton County, Texas filed December 22, 1999) and First State Bank of

Denton, et al. v. Mobil Oil Corp., et al., No. 8552-01 (Statutory Probate Court, Denton County, Texas filed March 29, 2001). These cases were originally filed as class actions on behalf of classes of overriding royalty interest owners (Shores) and royalty interest owners (Bank of Denton) for damages relating to alleged underpayment of royalties on carbon dioxide produced from the McElmo Dome Unit. On February 22, 2005, the trial judge dismissed both cases for lack of jurisdiction. Some of the individual plaintiffs in these cases re-filed their claims in new lawsuits (discussed below).

Gerald O. Bailey et al. v. Shell Oil Co. et al/Southern District of Texas Lawsuit

Kinder Morgan CO_2, Kinder Morgan Energy Partners, L.P. and Cortez Pipeline Company are among the defendants in a proceeding in the federal courts for the southern district of Texas. *Gerald O. Bailey et al. v. Shell Oil Company et al.*, (Civil Action Nos. 05-1029 and 05-1829 in the U.S. District Court for the Southern District of Texas—consolidated by Order dated July 18, 2005). The plaintiffs are asserting claims for the underpayment of royalties on carbon dioxide produced from the McElmo Dome Unit. The plaintiffs assert claims for fraud/fraudulent inducement, real estate fraud, negligent misrepresentation, breach of fiduciary and agency duties, breach of contract and covenants, violation of the Colorado Unfair Practices Act, civil theft under Colorado law, conspiracy, unjust enrichment, and open account. Plaintiffs Gerald O. Bailey, Harry Ptasynski, and W.L. Gray & Co. have also asserted claims as private relators under the False Claims Act and for violation of federal and Colorado antitrust laws. The plaintiffs seek actual damages, treble damages, punitive damages, a constructive trust and accounting, and declaratory relief. The defendants filed motions for summary judgment on all claims.

Effective March 5, 2007, all defendants and plaintiffs Bridwell Oil Company, the Alicia Bowdle Trust, and the Estate of Margaret Bridwell Bowdle executed a final settlement agreement which provides for the dismissal of these plaintiffs' claims with prejudice to being refiled. On June 10, 2007, the Houston federal district court entered an order of partial dismissal by which the claims by and against the settling plaintiffs were dismissed with prejudice. The claims asserted by Bailey, Ptasynski, and Gray are not included within the settlement or the order of partial dismissal. Effective April 8, 2008, the Shell and Kinder Morgan defendants and plaintiff Gray entered into an indemnification agreement that provides for the dismissal of Gray's claims with prejudice.

On April 22, 2008, the federal district court granted defendants' motions for summary judgment and ruled that plaintiffs Bailey, Ptasynski, and Gray take nothing on their claims. The court entered final judgment in favor of defendants on April 30, 2008. Defendants have filed a motion seeking sanctions against plaintiff Bailey. The plaintiffs have appealed the final judgment to the United States Fifth Circuit Court of Appeals.

CO_2 Claims Arbitration

Cortez Pipeline Company and Kinder Morgan CO_2, successor to Shell CO_2 Company, Ltd., were among the named defendants in CO_2 Committee, Inc. v. Shell Oil Co., et al., an arbitration initiated on November 28, 2005. The arbitration arose from a dispute over a class action settlement agreement which became final on July 7, 2003 and disposed of five lawsuits formerly pending in the U.S. District Court, District of Colorado. The plaintiffs in such lawsuits primarily included overriding royalty interest owners, royalty interest owners, and small share working interest owners who alleged underpayment of royalties and other payments on carbon dioxide produced from the McElmo Dome Unit. The settlement imposed certain future obligations on the defendants in the underlying litigation. The plaintiff in the arbitration is an entity that was formed as part of the settlement for the purpose of monitoring compliance with the obligations imposed by the settlement agreement. The plaintiff alleged that, in calculating royalty and other payments, defendants used a transportation expense in excess of what is allowed by the settlement agreement, thereby causing alleged underpayments of approximately $12 million. The plaintiff also alleged that Cortez Pipeline Company should have used certain funds to further reduce its debt, which, in turn, would have allegedly increased the value of royalty and other payments by approximately $0.5 million. Defendants denied that there was any breach of the settlement agreement. On August 7, 2006, the arbitration panel issued its opinion finding that defendants did not breach the settlement agreement. On October 25, 2006, the defendants filed an application to confirm the arbitration decision in New Mexico federal district court. On June 21, 2007, the New Mexico federal district court entered final judgment confirming the August 7, 2006 arbitration decision.

On October 2, 2007, the plaintiff initiated a second arbitration (CO2 Committee, Inc. v. Shell CO_2 Company, Ltd., aka Kinder Morgan CO_2 Company, L.P., et al.) against Cortez Pipeline Company, Kinder Morgan CO_2 and an ExxonMobil entity. The second arbitration asserts claims similar to those asserted in the first arbitration. On October 11, 2007, the defendants filed a Complaint for Declaratory Judgment and Injunctive Relief in federal district court in New Mexico. The Complaint seeks dismissal of the second arbitration on the basis of res judicata. In November 2007, the plaintiff in the arbitration moved to dismiss the defendants' Complaint on the grounds that the issues presented should be decided by a panel in a second arbitration. In December 2007, the defendants in the arbitration filed a motion seeking summary judgment on their Complaint and dismissal of the second arbitration. On May 16, 2008, the federal district court in New Mexico granted the plaintiff's motion to dismiss. On June 2, 2008, the defendants in the arbitration filed a motion in the New Mexico federal district court seeking an order confirming that the panel in the first arbitration can preside over the second arbitration. On June 3, 2008, the plaintiff filed a request with the American Arbitration Association seeking administration of the arbitration.

MMS Notice of Noncompliance and Civil Penalty

On December 20, 2006, Kinder Morgan CO_2 received a "Notice of Noncompliance and Civil Penalty: Knowing or Willful Submission of False, Inaccurate, or Misleading Information—Kinder Morgan CO_2 Company, L.P., Case No. CP07-001" from the U.S. Department of the Interior, Minerals Management Service, referred to in this note as the MMS. This Notice, and the MMS's position that Kinder Morgan CO_2 has violated certain reporting obligations, relates to a disagreement between the MMS and Kinder Morgan CO_2 concerning the approved transportation allowance to be used in valuing McElmo Dome carbon dioxide for purposes of calculating federal royalties. The Notice of Noncompliance and Civil Penalty assesses a civil penalty of approximately $2.2 million as of December 15, 2006 (based on a penalty of $500.00 per day for each of 17 alleged violations) for Kinder Morgan CO_2's alleged submission of false, inaccurate, or misleading information relating to the transportation allowance, and federal royalties for CO_2 produced at McElmo Dome, during the period from June 2005 through October 2006. The MMS contends that false, inaccurate, or misleading information was submitted in the 17 monthly Form 2014s containing remittance advice reflecting the royalty payments for the referenced period because they reflected Kinder Morgan CO_2's use of the Cortez Pipeline tariff as the transportation allowance. The MMS claims that the Cortez Pipeline tariff is not the proper transportation allowance and that Kinder Morgan CO_2 should have used its "reasonable actual costs" calculated in accordance with certain federal product valuation regulations as amended effective June 1, 2005. The MMS stated that civil penalties will continue to accrue at the same rate until the alleged violations are corrected.

The MMS set a due date of January 20, 2007 for Kinder Morgan CO_2's payment of the approximately $2.2 million in civil penalties, with interest to accrue daily on that amount in the event payment is not made by such date. Kinder Morgan CO_2 has not paid the penalty. On January 2, 2007, Kinder Morgan CO_2 submitted a response to the Notice of Noncompliance and Civil Penalty challenging the assessment in the Office of Hearings and Appeals of the Department of the Interior. On February 1, 2007, Kinder Morgan CO_2 filed a petition to stay the accrual of penalties until the dispute is resolved. On February 22, 2007, an administrative law judge of the U.S. Department of the Interior issued an order denying Kinder Morgan CO_2's petition to stay the accrual of penalties. A hearing on the Notice of Noncompliance and Civil Penalty was originally set for December 10, 2007. In November 2007, the MMS and Kinder Morgan CO_2 filed a joint motion to vacate the hearing date and stay the accrual of additional penalties to allow the parties to discuss settlement. In November 2007, the administrative law judge granted the joint motion, stayed accrual of additional penalties for the period from November 6, 2007 to February 18, 2008, and reset the hearing date to March 24, 2008. The parties conducted settlement conferences on February 4, 2008 and February 12, 2008. On February 14, 2008, the parties filed a joint motion seeking to vacate the March 24, 2008 hearing and to stay the accrual of additional penalties to allow the parties to continue their settlement discussions. On March 4, 2008, the administrative law judge granted the joint motion. The parties have reached a settlement of the Notice of Noncompliance and Civil Penalty. The settlement agreement is subject to final MMS approval.

Kinder Morgan CO_2 disputes the Notice of Noncompliance and Civil Penalty and believes that it has meritorious defenses. Kinder Morgan CO_2 contends that use of the Cortez Pipeline tariff as the transportation allowance for purposes of calculating federal royalties was approved by the MMS in 1984. This approval was later affirmed as open-ended by the Interior Board of Land Appeals in the 1990s. Accordingly, Kinder Morgan CO_2 has stated to the MMS that its use of the Cortez tariff as the approved federal transportation allowance is authorized and proper. Kinder Morgan CO_2 also disputes the allegation that it has knowingly or willfully submitted false, inaccurate, or misleading information to the MMS. Kinder Morgan CO_2's use of the Cortez Pipeline tariff as the approved federal transportation allowance has been the subject of extensive discussion between the parties. The MMS was, and is, fully apprised of that fact and of the royalty valuation and payment process followed by Kinder Morgan CO_2 generally.

MMS Order to Report and Pay

On March 20, 2007, Kinder Morgan CO_2 received an "Order to Report and Pay" from the MMS. The MMS contends that Kinder Morgan CO_2 has over-reported transportation allowances and underpaid royalties in the amount of approximately $4.6 million for the period from January 1, 2005 through December 31, 2006 as a result of its use of the Cortez Pipeline tariff as the transportation allowance in calculating federal royalties. As noted in the discussion of the Notice of Noncompliance and Civil Penalty proceeding, the MMS claims that the Cortez Pipeline tariff is not the proper transportation allowance and that Kinder Morgan CO_2 must use its "reasonable actual costs" calculated in accordance with certain federal product valuation regulations. The MMS set a due date of April 13, 2007 for Kinder Morgan CO_2's payment of the $4.6 million in claimed additional royalties, with possible late payment charges and civil penalties for failure to pay the assessed amount. Kinder Morgan CO_2 has not paid the $4.6 million, and on April 19, 2007, it submitted a notice of appeal and statement of reasons in response to the Order to Report and Pay, challenging the Order and appealing it to the Director of the MMS in accordance with 30 C.F.R. sec. 290.100, et seq. Also on April 19, 2007, Kinder Morgan CO_2 submitted a petition to suspend compliance with the Order to Report and Pay pending the appeal. The MMS granted Kinder Morgan CO_2's petition to suspend, and approved self-bonding on June 12, 2007. Kinder Morgan CO_2 filed a supplemental statement of reasons in support of its appeal of the Order to Report and Pay on June 15, 2007.

In addition to the March 2007 Order to Report and Pay, in April 2007, Kinder Morgan CO_2 received an "Audit Issue Letter" sent by the Colorado Department of Revenue on behalf of the U.S. Department of the Interior. In the letter, the Department of Revenue states that Kinder Morgan CO_2 has over-reported transportation allowances and underpaid royalties (due to the use of the Cortez Pipeline tariff as the transportation allowance for purposes of federal royalties) in the amount of $8.5 million for the period from April 2000 through December 2004. Kinder Morgan CO_2 responded to the letter in May 2007, outlining its position why use of the Cortez tariff-based transportation allowance is proper. On August 8, 2007, Kinder Morgan CO_2 received an "Order to Report and Pay Additional Royalties" from the MMS. As alleged in the Colorado Audit Issue Letter, the MMS contends that Kinder Morgan CO_2 has over-reported transportation allowances and underpaid royalties in the amount of approximately $8.5 million for the period from April 2000 through December 2004. The MMS's claims underlying the August 2007 Order to Report and Pay are similar to those at issue in the March 2007 Order to Report and Pay. On September 7, 2007, Kinder Morgan CO_2 submitted a notice of appeal and statement of reasons in response to the August 2007 Order to Report and Pay, challenging the Order and appealing it to the Director of the MMS in accordance with 30 C.F.R. sec. 290.100, et seq. Also on September 7, 2007, Kinder Morgan CO_2 submitted a petition to suspend compliance with the Order to Report and Pay pending the appeal. The MMS granted Kinder Morgan CO_2's petition to suspend, and approved self-bonding on September 11, 2007.

The MMS and Kinder Morgan CO_2 have agreed to stay the March 2007 and August 2007 Order to Report and Pay proceedings to allow the parties to discuss settlement. The parties conducted settlement conferences on February 4, 2008 and February 12, 2008 and have reached a settlement of the March 2007 and August 2007 Orders to Report and Pay. The settlement agreement is subject to final MMS approval.

Kinder Morgan CO_2 disputes both the March and August 2007 Orders to Report and Pay and the Colorado Department of Revenue Audit Issue Letter, and as noted above, it contends that use of the Cortez Pipeline tariff as the transportation allowance for purposes of calculating federal royalties was approved by the MMS in 1984 and was affirmed as open-ended by the Interior Board of Land Appeals in the 1990s. The appeals to the MMS Director of the Orders to Report and Pay do not provide for an oral hearing. No further submission or briefing deadlines have been set.

J. Casper Heimann, Pecos Slope Royalty Trust and Rio Petro LTD, individually and on behalf of all other private royalty and overriding royalty owners in the Bravo Dome Carbon Dioxide Unit, New Mexico similarly situated v. Kinder Morgan CO_2 Company, L.P., No. 04-26-CL (8th Judicial District Court, Union County New Mexico)

This case involves a purported class action against Kinder Morgan CO_2 alleging that it has failed to pay the full royalty and overriding royalty ("royalty interests") on the true and proper settlement value of compressed carbon dioxide produced from the Bravo Dome Unit during the period beginning January 1, 2000. The complaint purports to assert claims for violation of the New Mexico Unfair Practices Act, constructive fraud, breach of contract and of the covenant of good faith and fair dealing, breach of the implied covenant to market, and claims for an accounting, unjust enrichment, and injunctive relief. The purported class is comprised of current and former owners, during the period January 2000 to the present, who have private property royalty interests burdening the oil and gas leases held by the defendant, excluding the Commissioner of Public Lands, the United States of America, and those private royalty interests that are not unitized as part of the Bravo Dome Unit. The plaintiffs allege that they were members of a class previously certified as a class action by the United States District Court for the District of New Mexico in the matter Doris Feerer, et al. v. Amoco Production Company, et al., USDC N.M. Civ. No. 95-0012 (the "Feerer Class Action"). Plaintiffs allege that Kinder Morgan CO_2's method of paying royalty interests is contrary to the settlement of the Feerer Class Action. Kinder Morgan CO_2 filed a motion to compel arbitration of this matter pursuant to the arbitration provisions contained in the Feerer Class Action settlement agreement, which motion was denied. Kinder Morgan CO_2 appealed this decision to the New Mexico Court of Appeals, which affirmed the decision of the trial court. The New Mexico Supreme Court granted further review in October 2006, and after hearing oral argument, the New Mexico Supreme Court quashed its prior order granting review. In August 2007, Kinder Morgan CO_2 filed a petition for writ of certiorari with the United States Supreme Court seeking further review. The Petition was denied in December 2007. The case was tried in the trial court in September 2008. The plaintiffs sought $6.8 million in actual damages as well as punitive damages. The jury returned a verdict finding that Kinder Morgan did not breach the settlement agreement and did not breach the claimed duty to market carbon dioxide. The jury also found that Kinder Morgan breached a duty of good faith and fair dealing and found compensatory damages of $0.3 million and punitive damages of $1.2 million. On October 16, 2008, the trial court entered judgment on the verdict.

In addition to the matters listed above, audits and administrative inquiries concerning Kinder Morgan CO_2's payments on carbon dioxide produced from the McElmo Dome and Bravo Dome Units are currently ongoing. These audits and inquiries involve federal agencies and the States of Colorado and New Mexico.

Commercial Litigation Matters

Union Pacific Railroad Company Easements

SFPP, L.P. and Union Pacific Railroad Company (the successor to Southern Pacific Transportation Company and referred to in this note as UPRR) are engaged in a proceeding to determine the extent, if any, to which the rent payable by SFPP for the use of pipeline easements on rights-of-way held by UPRR should be adjusted pursuant to existing contractual arrangements for the ten year period beginning January 1, 2004 (*Union Pacific Railroad Company vs. Santa Fe Pacific Pipelines, Inc., SFPP, L.P., Kinder Morgan Operating L.P. "D", Kinder Morgan G.P., Inc., et al.,* Superior Court of the State of California for the County of Los Angeles, filed July 28, 2004). In February 2007, a trial began to determine the amount payable for easements on UPRR rights-of-way. The trial is ongoing and is expected to conclude in the first quarter of 2009.

SFPP and UPRR are also engaged in multiple disputes over the circumstances under which SFPP must pay for a relocation of its pipeline within the UPRR right of way and the safety standards that govern relocations. SFPP believes that it must pay for relocation of the pipeline only when so required by the railroad's common carrier operations, and in doing so, it need only comply with standards set forth in the federal Pipeline Safety Act in conducting relocations. In July 2006, a trial before a judge regarding the circumstances under which SFPP must pay for relocations concluded, and the judge determined that SFPP must pay for any relocations resulting from any legitimate business purpose of the UPRR. SFPP has appealed this decision. In addition, UPRR contends that it has complete discretion to cause the pipeline to be relocated at SFPP's expense at any time and for any reason, and that

SFPP must comply with the more expensive American Railway Engineering and Maintenance-of-Way standards. Each party is seeking declaratory relief with respect to its positions regarding relocations.

It is difficult to quantify the effects of the outcome of these cases on SFPP because SFPP does not know UPRR's plans for projects or other activities that would cause pipeline relocations. Even if SFPP is successful in advancing its positions, significant relocations for which SFPP must nonetheless bear the expense (i.e. for railroad purposes, with the standards in the federal Pipeline Safety Act applying) would have an adverse effect on our financial position and results of operations. These effects would be even greater in the event SFPP is unsuccessful in one or more of these litigations.

United States of America, ex rel., Jack J. Grynberg v. K N Energy (Civil Action No. 97-D-1233, filed in the U.S. District Court, District of Colorado).

This multi-district litigation proceeding involves four lawsuits filed in 1997 against numerous Kinder Morgan companies. These suits were filed pursuant to the federal False Claims Act and allege underpayment of royalties due to mismeasurement of natural gas produced from federal and Indian lands. The complaints are part of a larger series of similar complaints filed by Mr. Grynberg against 77 natural gas pipelines (approximately 330 other defendants) in various courts throughout the country which were consolidated and transferred to the District of Wyoming.

In May 2005, a Special Master appointed in this litigation found that because there was a prior public disclosure of the allegations and that Grynberg was not an original source, the Court lacked subject matter jurisdiction. As a result, the Special Master recommended that the Court dismiss all the Kinder Morgan defendants. In October 2006, the United States District Court for the District of Wyoming upheld the dismissal of each case against the Kinder Morgan defendants on jurisdictional grounds. Grynberg has appealed this Order to the Tenth Circuit Court of Appeals. Briefing was completed and oral argument was held on September 25, 2008. No decision has yet been issued.

Prior to the dismissal order on jurisdictional grounds, the Kinder Morgan defendants filed Motions to Dismiss and for Sanctions alleging that Grynberg filed his Complaint without evidentiary support and for an improper purpose. On January 8, 2007, after the dismissal order, the Kinder Morgan defendants also filed a Motion for Attorney Fees under the False Claim Act. On April 24, 2007 the Court held a hearing on the Motions to Dismiss and for Sanctions and the Requests for Attorney Fees. A decision is still pending on the Motions to Dismiss and for Sanctions and the Requests for Attorney Fees.

Weldon Johnson and Guy Sparks, individually and as Representative of Others Similarly Situated v. Centerpoint Energy, Inc. et. al., No. 04-327-2 (Circuit Court, Miller County Arkansas).

On October 8, 2004, plaintiffs filed the above-captioned matter against numerous defendants including Kinder Morgan Texas Pipeline L.P.; Kinder Morgan Energy Partners, L.P.; Kinder Morgan G.P., Inc.; KM Texas Pipeline, L.P.; Kinder Morgan Texas Pipeline G.P., Inc.; Kinder Morgan Tejas Pipeline G.P., Inc.; Kinder Morgan Tejas Pipeline, L.P.; Gulf Energy Marketing, LLC; Tejas Gas, LLC; and MidCon Corp. (the "Kinder Morgan defendants"). The complaint purports to bring a class action on behalf of those who purchased natural gas from the CenterPoint defendants from October 1, 1994 to the date of class certification.

The complaint alleges that CenterPoint Energy, Inc., by and through its affiliates, has artificially inflated the price charged to residential consumers for natural gas that it allegedly purchased from the non-CenterPoint defendants, including the Kinder Morgan defendants. The complaint further alleges that in exchange for CenterPoint's purchase of such natural gas at above market prices, the non-CenterPoint defendants, including the Kinder Morgan defendants, sell natural gas to CenterPoint's non-regulated affiliates at prices substantially below market, which in turn sells such natural gas to commercial and industrial consumers and gas marketers at market price. The complaint purports to assert claims for fraud, unlawful enrichment and civil conspiracy against all of the defendants, and seeks relief in the form of actual, exemplary and punitive damages, interest, and attorneys' fees. On June 8, 2007, the Arkansas Supreme Court held that the Arkansas Public Service Commission, referred to in this report as the APSC, has exclusive jurisdiction over any Arkansas plaintiffs' claims that consumers were overcharged for gas in Arkansas and mandated that any such claims be dismissed from this lawsuit. On February 14, 2008, the

Arkansas Supreme Court clarified its previously issued order and mandated that the trial court dismiss the lawsuit in its entirety. On February 29, 2008 the trial court dismissed the case in its entirety. The APSC has initiated an investigation into the allegations set forth in the plaintiffs' complaint.

Leukemia Cluster Litigation

Richard Jernee, et al v. Kinder Morgan Energy Partners, et al, No. CV03-03482 (Second Judicial District Court, State of Nevada, County of Washoe) ("Jernee").

Floyd Sands, et al v. Kinder Morgan Energy Partners, et al, No. CV03-05326 (Second Judicial District Court, State of Nevada, County of Washoe) ("Sands").

On May 30, 2003, plaintiffs, individually and on behalf of Adam Jernee, filed a civil action in the Nevada State trial court against us and several Kinder Morgan related entities and individuals and additional unrelated defendants. Plaintiffs in the Jernee matter claim that defendants negligently and intentionally failed to inspect, repair and replace unidentified segments of their pipeline and facilities, allowing "harmful substances and emissions and gases" to damage "the environment and health of human beings." Plaintiffs claim that "Adam Jernee's death was caused by leukemia that, in turn, is believed to be due to exposure to industrial chemicals and toxins." Plaintiffs purport to assert claims for wrongful death, premises liability, negligence, negligence per se, intentional infliction of emotional distress, negligent infliction of emotional distress, assault and battery, nuisance, fraud, strict liability (ultra hazardous acts), and aiding and abetting, and seek unspecified special, general and punitive damages.

On August 28, 2003, a separate group of plaintiffs, represented by the counsel for the plaintiffs in the Jernee matter, individually and on behalf of Stephanie Suzanne Sands, filed a civil action in the Nevada State trial court against the same defendants and alleging the same claims as in the Jernee case with respect to Stephanie Suzanne Sands. The Jernee case has been consolidated for pretrial purposes with the Sands case. In May 2006, the court granted defendants' motions to dismiss as to the counts purporting to assert claims for fraud, but denied defendants' motions to dismiss as to the remaining counts, as well as defendants' motions to strike portions of the complaint. Defendant Kennametal, Inc. has filed a third-party complaint naming the United States and the United States Navy (the "United States") as additional defendants.

In response, the United States removed the case to the United States District Court for the District of Nevada and filed a motion to dismiss the third-party complaint. Plaintiff has also filed a motion to dismiss the United States and/or to remand the case back to state court. By order dated September 25, 2007, the United States District Court granted the motion to dismiss the United States from the case and remanded the Jernee and Sands cases back to the Second Judicial District Court, State of Nevada, County of Washoe. The cases will now proceed in the State Court. Based on the information available to date, our own preliminary investigation, and the positive results of investigations conducted by State and Federal agencies, we believe that the remaining claims against us in these matters are without merit and intend to defend against them vigorously.

Pipeline Integrity and Releases

From time to time, our pipelines experience leaks and ruptures. These leaks and ruptures may cause explosions, fire, damage to the environment, damage to property and/or personal injury or death. In connection with these incidents, we may be sued for damages caused by an alleged failure to properly mark the locations of our pipelines and/or to properly maintain our pipelines. Depending upon the facts and circumstances of a particular incident, state and federal regulatory authorities may seek civil and/or criminal fines and penalties.

We believe that we conduct our operations in accordance with applicable law. We seek to cooperate with state and federal regulatory authorities in connection with the clean-up of the environment caused by such leaks and ruptures and with any investigations as to the facts and circumstances surrounding the incidents.

Pasadena Terminal Fire

On September 23, 2008, a fire occurred in the pit 3 manifold area of our Pasadena, Texas terminal facility. One of our employees was injured and subsequently died. In addition, the pit 3 manifold was severely damaged. The

cause of the incident is currently under investigation by the Railroad Commission of Texas and the United States Occupational Safety and Health Administration. The remainder of the facility returned to normal operations within 24 hours of the incident.

Walnut Creek, California Pipeline Rupture

On November 9, 2004, excavation equipment operated by Mountain Cascade, Inc., a third-party contractor on a water main installation project hired by East Bay Municipal Utility District, struck and ruptured an underground petroleum pipeline owned and operated by SFPP, L.P. in Walnut Creek, California. An explosion occurred immediately following the rupture that resulted in five fatalities and several injuries to employees or contractors of Mountain Cascade. The explosion and fire also caused property damage.

On May 5, 2005, the California Division of Occupational Safety and Health ("CalOSHA") issued two civil citations against us relating to this incident assessing civil fines of approximately $0.1 million based upon our alleged failure to mark the location of the pipeline properly prior to the excavation of the site by the contractor. On March 24, 2008, we agreed to a settlement with CalOSHA by which the two citations would be reduced to two "unclassified" violations of the CalOSHA regulations and we would pay a fine of $140,000. The settlement is currently awaiting approval by the CalOSHA Appeals Board.

On June 27, 2005, the Office of the California State Fire Marshal, Pipeline Safety Division, referred to in this report as the CSFM, issued a notice of violation against us which also alleged that we did not properly mark the location of the pipeline in violation of state and federal regulations. The CSFM assessed a proposed civil penalty of $0.5 million. On September 9, 2008, we reached an agreement with the CSFM to settle the proposed civil penalty for approximately $0.3 million with no admission of liability.

As a result of the accident, nineteen separate lawsuits were filed. The majority of the cases were personal injury and wrongful death actions that alleged, among other things, that SFPP/Kinder Morgan failed to properly field mark the area where the accident occurred.

Following court ordered mediation, the Kinder Morgan defendants have settled with plaintiffs in all of the wrongful death cases and the personal injury and property damages cases. The only remaining civil case is a claim for equitable indemnity by an engineering company defendant against Kinder Morgan G.P. Services Co., Inc. We have filed a Motion for Summary Judgment with respect to all of the claims in this matter, which motion is currently pending.

Rockies Express Pipeline LLC Wyoming Construction Incident

On November 11, 2006, a bulldozer operated by an employee of Associated Pipeline Contractors, Inc, (a third-party contractor to Rockies Express Pipeline LLC, referred to in this note as REX), struck an existing subsurface natural gas pipeline owned by Wyoming Interstate Company, a subsidiary of El Paso Pipeline Group. The pipeline was ruptured, resulting in an explosion and fire. The incident occurred in a rural area approximately nine miles southwest of Cheyenne, Wyoming. The incident resulted in one fatality (the operator of the bulldozer) and there were no other reported injuries. The cause of the incident was investigated by the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration, referred to in this report as the PHMSA. In March 2008, PHMSA issued a Notice of Probable Violation, Proposed Civil Penalty and Proposed Compliance Order ("NOPV") to El Paso Corporation in which it concluded that El Paso failed to comply with federal law and its internal policies and procedures regarding protection of its pipeline, resulting in this incident. To date, PHMSA has not issued any NOPV's to REX, and we do not expect that it will do so. Immediately following the incident, REX and El Paso Pipeline Group reached an agreement on a set of additional enhanced safety protocols designed to prevent the reoccurrence of such an incident.

In September 2007, the family of the deceased bulldozer operator filed a wrongful death action against us, REX and several other parties in the District Court of Harris County, Texas, 189 Judicial District, at case number 2007-57916. The plaintiffs seek unspecified compensatory and exemplary damages plus interest, attorney's fees and costs of suit. We have asserted contractual claims for complete indemnification for any and all costs arising from this incident, including any costs related to this lawsuit, against third parties and their insurers. On March 25, 2008 we entered into a settlement agreement with one of the plaintiffs, the decedent's daughter, resolving any and all of her claims against us, REX and its contractors. We were indemnified for the full amount of this settlement by one of REX's contractors. On October 17, 2008, the remaining plaintiffs filed a Notice of Nonsuit, which dismissed the remaining claims against all defendants without prejudice to the plaintiffs' ability to re-file their claims at a later date.

Charlotte, North Carolina

On November 27, 2006, the Plantation Pipeline experienced a release of approximately 4,000 gallons of gasoline from a Plantation Pipe Line Company block valve on a delivery line into a terminal owned by a third party company. Upon discovery of the release, Plantation immediately locked out the delivery of gasoline through that pipe to prevent further releases. Product had flowed onto the surface and into a nearby stream, which is a tributary of Paw Creek, and resulted in loss of fish and other biota. Product recovery and remediation efforts were implemented immediately, including removal of product from the stream. The line was repaired and put back into service within a few days. Remediation efforts are continuing under the direction of the North Carolina Department of Environment and Natural Resources (the "NCDENR"), which issued a Notice of Violation and Recommendation of Enforcement against Plantation on January 8, 2007. Plantation continues to cooperate fully with the NCDENR.

Although Plantation does not believe that penalties are warranted, it has engaged in settlement discussions with the EPA regarding a potential civil penalty for the November 2006 release as part of broader settlement negotiations with the EPA regarding this spill and three other historical releases from Plantation, including a February 2003 release near Hull, Georgia. Plantation has entered into a consent decree with the Department of Justice and the EPA for all four releases for approximately $0.7 million, plus some additional work to be performed to prevent future releases. Although it is not possible to predict the ultimate outcome, we believe, based on our experiences to date, that the ultimate resolution of such items will not have a material adverse impact on our business, financial position, results of operations or cash flows.

In addition, in April 2007, during pipeline maintenance activities near Charlotte, North Carolina, Plantation discovered the presence of historical soil contamination near the pipeline, and reported the presence of impacted soils to the NCDENR. Subsequently, Plantation contacted the owner of the property to request access to the property to investigate the potential contamination. The results of that investigation indicate that there is soil and groundwater contamination which appears to be from an historical turbine fuel release. The groundwater contamination is underneath at least two lots on which there is current construction of single family homes as part of a new residential development. Further investigation and remediation are being conducted under the oversight of the NCDENR. Plantation reached a settlement with the builder of the residential subdivision. Plantation continues to negotiate with the owner of the property to address any potential claims that it may bring.

Barstow, California

The United States Department of Navy has alleged that historic releases of methyl tertiary-butyl ether, referred to in this report as MTBE, from Calnev Pipe Line Company's Barstow terminal (i) has migrated underneath the Navy's Marine Corps Logistics Base in Barstow; (ii) has impacted the Navy's existing groundwater treatment system for unrelated groundwater contamination not alleged to have been caused by Calnev; and (iii) could affect the MCLB's water supply system. Although Calnev believes that it has certain meritorious defenses to the Navy's claims, it is working with the Navy to agree upon an Administrative Settlement Agreement and Order on Consent for CERCLA Removal Action to reimburse the Navy for $0.5 million in past response actions, plus perform other work to ensure protection of the Navy's existing treatment system and water supply.

Oil Spill Near Westridge Terminal, Burnaby, British Columbia

On July 24, 2007, a third-party contractor installing a sewer line for the City of Burnaby struck a crude oil pipeline segment included within our Trans Mountain pipeline system near its Westridge terminal in Burnaby, BC, resulting in a release of approximately 1,400 barrels of crude oil. The release impacted the surrounding neighborhood, several homes and nearby Burrard Inlet. No injuries were reported. To address the release, we initiated a comprehensive emergency response in collaboration with, among others, the City of Burnaby, the BC Ministry of Environment, the National Energy Board, and the National Transportation Safety Board. Cleanup and environmental remediation is near completion. The incident is currently under investigation by Federal and

Provincial agencies. We do not expect this matter to have a material adverse impact on our results of operations or cash flows.

On December 20, 2007 we initiated a lawsuit entitled Trans Mountain Pipeline LP, Trans Mountain Pipeline Inc. and Kinder Morgan Canada Inc. v. The City of Burnaby, et al., Supreme Court of British Columbia, Vancouver Registry No. S078716. The suit alleges that the City of Burnaby and its agents are liable in damages including, but not limited to, all costs and expenses incurred by us as a result of the rupture of the pipeline and subsequent release of crude oil. Defendants have denied liability and discovery has begun.

Although no assurance can be given, we believe that we have meritorious defenses to the actions set forth in this note and, to the extent an assessment of the matter is possible, if it is probable that a liability has been incurred and the amount of loss can be reasonably estimated, we believe that we have established an adequate reserve to cover potential liability.

Additionally, although it is not possible to predict the ultimate outcomes, we also believe, based on our experiences to date, that the ultimate resolution of these matters will not have a material adverse impact on our business, financial position, results of operations or cash flows. As of September 30, 2008, and December 31, 2007, we have recorded a total reserve for legal fees, transportation rate cases and other litigation liabilities in the amount of $232.5 million and $247.9 million, respectively. The reserve is primarily related to various claims from lawsuits arising from our Pacific operations' pipeline transportation rates, and the contingent amount is based on both the circumstances of probability and reasonability of dollar estimates. We regularly assess the likelihood of adverse outcomes resulting from these claims in order to determine the adequacy of our liability provision.

Environmental Matters

Exxon Mobil Corporation v. GATX Corporation, Kinder Morgan Liquids Terminals, Inc. and ST Services, Inc.

On April 23, 2003, Exxon Mobil Corporation filed a complaint in the Superior Court of New Jersey, Gloucester County. We filed our answer to the complaint on June 27, 2003, in which we denied ExxonMobil's claims and allegations as well as included counterclaims against ExxonMobil. The lawsuit relates to environmental remediation obligations at a Paulsboro, New Jersey liquids terminal owned by ExxonMobil from the mid-1950s through November 1989, by GATX Terminals Corp. from 1989 through September 2000, later owned by ST Services, Inc. Prior to selling the terminal to GATX Terminals, ExxonMobil performed the environmental site assessment of the terminal required prior to sale pursuant to state law. During the site assessment, ExxonMobil discovered items that required remediation and the New Jersey Department of Environmental Protection issued an order that required ExxonMobil to perform various remediation activities to remove hydrocarbon contamination at the terminal. ExxonMobil, we understand, is still remediating the site and has not been removed as a responsible party from the state's cleanup order; however, ExxonMobil claims that the remediation continues because of GATX Terminals' storage of a fuel additive, MTBE, at the terminal during GATX Terminals' ownership of the terminal. When GATX Terminals sold the terminal to ST Services, the parties indemnified one another for certain environmental matters. When GATX Terminals was sold to us, GATX Terminals' indemnification obligations, if any, to ST Services may have passed to us.

Consequently, at issue is any indemnification obligation we may owe to ST Services for environmental remediation of MTBE at the terminal. The complaint seeks any and all damages related to remediating MTBE at the terminal, and, according to the New Jersey Spill Compensation and Control Act, treble damages may be available for actual dollars incorrectly spent by the successful party in the lawsuit for remediating MTBE at the terminal. The parties are currently involved in mandatory mediation and met in June and October 2008. No progress was made at any of the mediations. The parties continue to conduct limited discovery. Currently, the mediation judge has ordered all parties' technical consultants to meet to discuss and finalize a remediation program. Following that meeting, it is anticipated that the parties will again convene for another mediation.

On June 25, 2007, the New Jersey Department of Environmental Protection, the Commissioner of the New Jersey Department of Environmental Protection and the Administrator of the New Jersey Spill Compensation Fund, referred to collectively as the plaintiffs, filed a complaint against ExxonMobil Corporation and GATX Terminals Corporation. The complaint was filed in Gloucester County, New Jersey. Both ExxonMobil and we filed third party complaints against ST Services seeking to bring ST into the case. ST Services filed motions to dismiss the

third party complaints. Recently, the court denied ST's motions to dismiss and ST is now joined in the case. Defendants will now file their answers in the case. The plaintiffs seek the costs and damages that the plaintiffs allegedly have incurred or will incur as a result of the discharge of pollutants and hazardous substances at the Paulsboro, New Jersey facility. The costs and damages that the plaintiffs seek include damages to natural resources. In addition, the plaintiffs seek an order compelling the defendants to perform or fund the assessment and restoration of those natural resource damages that are the result of the defendants' actions. As in the case brought by ExxonMobil against GATX Terminals, the issue is whether the plaintiffs' claims are within the scope of the indemnity obligations between GATX Terminals (and therefore, Kinder Morgan Liquids Terminals) and ST Services. ST Services is the current owner and operator at the facility. The court may consolidate the two cases.

Mission Valley Terminal Lawsuit

In August 2007, the City of San Diego, on its own behalf and purporting to act on behalf of the People of the state of California, filed a lawsuit against us and several affiliates seeking injunctive relief and unspecified damages allegedly resulting from hydrocarbon and MTBE impacted soils and groundwater beneath the city's stadium property in San Diego arising from historic operations at the Mission Valley terminal facility. The case was filed in the Superior Court of California, San Diego County, case number 37-2007-00073033-CU-OR-CTL. On September 26, 2007, we removed the case to the United States District Court, Southern District of California, case number 07CV1883WCAB. On October 3, 2007, we filed a Motion to Dismiss all counts of the Complaint. The court denied in part and granted in part the Motion to Dismiss and gave the City leave to amend their complaint. The City submitted its Amended Complaint and we filed an Answer. The parties have commenced with discovery. This site has been, and currently is, under the regulatory oversight and order of the California Regional Water Quality Control Board.

In June 2008, we received an Administrative Civil Liability Complaint from the California Regional Water Quality Control Board for violations and penalties associated with permitted surface water discharge from the remediation system operating at the Mission Valley terminal facility. Currently, we are negotiating a settlement that should include a reduction of alleged violations and associated penalties as well as resolve any past and future issues related to permitted surface water discharge from the remediation system. We do not expect the cost of the settlement to be material.

Portland Harbor DOJ/EPA Investigation

In April 2008, we reached an agreement in principle with the United States Attorney's office for the District of Oregon and the United States Department of Justice regarding a former employee's involvement in the improper disposal of potash (potassium chloride) into the Pacific Ocean in August 2003 at our Portland, Oregon bulk terminal facility. The incident involved an employee making arrangements to have a customer's shipment of potash, which had become wet and no longer met specifications for commercial use, improperly disposed of at sea without a permit. On August 13, 2008, we completed the settlement.

We have fully cooperated with the government's investigation and promptly adopted measures at the terminal to avoid future incidents of this nature. To settle the matter, we entered a plea to a criminal violation of the Ocean Dumping Act, pay a fine of approximately $0.2 million, and make a community service payment of approximately $0.1 million to the Oregon Governor's Fund for the Environment. As part of the settlement, the government and we acknowledged in a joint factual statement of fact filed with the court that (i) no harm was done to the environment; (ii) the former employee's actions constituted a violation of company policy; (iii) we did not benefit financially from the incident; and (iv) no personnel outside of the Portland terminal either approved or had any knowledge of the former employee's arrangements.

Other Environmental

We are subject to environmental cleanup and enforcement actions from time to time. In particular, the federal Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) generally imposes joint and several liability for cleanup and enforcement costs on current or predecessor owners and operators of a site, among others, without regard to fault or the legality of the original conduct. Our operations are also subject to federal, state and local laws and regulations relating to protection of the environment. Although we believe our operations are in substantial compliance with applicable environmental law and regulations, risks of additional costs and liabilities are

inherent in pipeline, terminal and carbon dioxide field and oil field operations, and there can be no assurance that we will not incur significant costs and liabilities. Moreover, it is possible that other developments, such as increasingly stringent environmental laws, regulations and enforcement policies thereunder, and claims for damages to property or persons resulting from our operations, could result in substantial costs and liabilities to us.

We are currently involved in several governmental proceedings involving air, water and waste violations issued by various governmental authorities related to compliance with environmental regulations. As we receive notices of non-compliance, we negotiate and settle these matters. We do not believe that these violations will have a material adverse affect on our business.

We are also currently involved in several governmental proceedings involving groundwater and soil remediation efforts under administrative orders or related state remediation programs issued by various regulatory authorities related to compliance with environmental regulations associated with our assets. We have established a reserve to address the costs associated with the cleanup.

In addition, we are involved with and have been identified as a potentially responsible party in several federal and state superfund sites. Environmental reserves have been established for those sites where our contribution is probable and reasonably estimable. In addition, we are from time to time involved in civil proceedings relating to damages alleged to have occurred as a result of accidental leaks or spills of refined petroleum products, natural gas liquids, natural gas and carbon dioxide. See "—Pipeline Integrity and Releases" above for additional information with respect to ruptures and leaks from our pipelines.

Although it is not possible to predict the ultimate outcomes, we believe that the resolution of the environmental matters set forth in this note will not have a material adverse effect on our business, financial position, results of operations or cash flows. However, we are not able to reasonably estimate when the eventual settlements of these claims will occur and changing circumstances could cause these matters to have a material adverse impact. As of September 30, 2008, we have accrued an environmental reserve of$72.1 million, and we believe the establishment of this environmental reserve is adequate such that the resolution of pending environmental matters will not have a material adverse impact on our business, cash flows, financial position or results of operations. As of December 31, 2007, our environmental reserve totaled $92.0 million. Additionally, many factors may change in the future affecting our reserve estimates, such as (i) regulatory changes; (ii) groundwater and land use near our sites; and (iii) changes in cleanup technology.

Other

We are a defendant in various lawsuits arising from the day-to-day operations of our businesses. Although no assurance can be given, we believe, based on our experiences to date, that the ultimate resolution of such items will not have a material adverse impact on our business, financial position, results of operations or cash flows.

4. Asset Retirement Obligations

According to the provisions of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations," we record liabilities for obligations related to the retirement and removal of long-lived assets used in our businesses. We record, as liabilities, the fair value of asset retirement obligations on a discounted basis when they are incurred, which is typically at the time the assets are installed or acquired. Amounts recorded for the related assets are increased by the amount of these obligations. Over time, the liabilities increase due to the change in their present value, and the initial capitalized costs will be depreciated over the useful lives of the related assets. The liabilities are eventually extinguished when the asset is taken out of service.

In our CO_2 business segment, we are required to plug and abandon oil and gas wells that have been removed from service and to remove our surface wellhead equipment and compressors. As of September 30, 2008 and December 31, 2007, we have recognized asset retirement obligations in the aggregate amount of $73.3 million and $49.2 million, respectively, relating to these requirements at existing sites within our CO_2 business segment. The $24.1 million increase since December 31, 2007 was primarily related to higher estimated service, material and equipment costs related to our legal obligations associated with the retirement of tangible long-lived assets.

In our Natural Gas Pipelines business segment, the operating systems are composed of underground piping, compressor stations and associated facilities, natural gas storage facilities and certain other facilities and equipment. Currently, we have no plans to abandon any of these facilities, the majority of which have been providing utility services for many years. However, if we were to cease providing utility services in total or in any particular area, we would be required to remove certain surface facilities and equipment from land belonging to our customers and others (we would generally have no obligations for removal or remediation with respect to equipment and facilities, such as compressor stations, located on land we own). We believe we can reasonably estimate both the time and costs associated with the retirement of these facilities and as of September 30, 2008 and December 31, 2007, we have recognized asset retirement obligations in the aggregate amount of $2.3 million and $3.0 million, respectively, relating to the businesses within our Natural Gas Pipelines business segment.

We have included $1.4 million of our total asset retirement obligations as of September 30, 2008 with “Accrued other current liabilities” in our accompanying consolidated balance sheet. The remaining $74.2 million obligation is reported separately as a non-current liability. A reconciliation of the beginning and ending aggregate carrying amount of our asset retirement obligations for each of the nine months ended September 30, 2008 and 2007 is as follows (in millions):

	Nine Months Ended September 30,	
	2008	**2007**
Balance at beginning of period	$ 52.2	$ 50.3
Liabilities incurred	25.5	0.2
Liabilities settled	(4.5)	(0.6)
Accretion expense	2.4	2.0
Balance at end of period	$ 75.6	$ 51.9

We have various other obligations throughout our businesses to remove facilities and equipment on rights-of- way and other leased facilities. We currently cannot reasonably estimate the fair value of these obligations because the associated assets have indeterminate lives. These assets include pipelines, certain processing plants and distribution facilities, and certain bulk and liquids terminal facilities. An asset retirement obligation, if any, will be recognized once sufficient information is available to reasonably estimate the fair value of the obligation.

5. Distributions

On August 14, 2008, we paid a cash distribution of $0.99 per unit to our common unitholders and our Class B unitholders for the quarterly period ended June 30, 2008. KMR, our sole i-unitholder, received 1,359,153 additional i-units based on the $0.99 cash distribution per common unit. The distributions were declared on July 16, 2008, payable to unitholders of record as of July 31, 2008.

On October 15, 2008, we declared a cash distribution of $1.02 per unit for the quarterly period ended September 30, 2008. The distribution will be paid on November 14, 2008, to unitholders of record as of October 31, 2008. Our common unitholders and Class B unitholders will receive cash. KMR will receive a distribution of 1,646,891 additional i-units based on the $1.02 distribution per common unit. For each outstanding i-unit that KMR holds, a fraction of an i-unit (0.021570) will be issued. This fraction was determined by dividing:

- $1.02, the cash amount distributed per common unit

by

- $47.287, the average of KMR’s shares’ closing market prices from October 15-28, 2008, the ten consecutive trading days preceding the date on which the shares began to trade ex-dividend under the rules of the New York Stock Exchange.

6. Intangibles

Goodwill

For our investments in affiliated entities that are included in our consolidation, the excess cost over underlying fair value of net assets is referred to as goodwill and reported separately as "Goodwill" in our accompanying consolidated balance sheets. Goodwill is not subject to amortization but must be tested for impairment at least annually. This test requires us to assign goodwill to an appropriate reporting unit and to determine if the implied fair value of the reporting unit's goodwill is less than its carrying amount.

On April 18, 2007, we announced that we would acquire the Trans Mountain pipeline system from Knight, and this transaction was completed April 30, 2007 (see Note 2). Following the provisions of generally accepted accounting principles, the consideration of this transaction caused Knight to consider the fair value of the Trans Mountain pipeline system, and to determine whether goodwill related to these assets was impaired. Based on this determination, Knight recorded a goodwill impairment charge of $377.1 million in the first quarter of 2007, and because we have included all of the historical results of Trans Mountain as though the net assets had been transferred to us on January 1, 2006, this impairment expense is now reflected in our consolidated results of operations.

Changes in the carrying amount of our goodwill for the nine months ended September 30, 2008 are summarized as follows (in millions):

	Products Pipelines	Natural Gas Pipelines	CO_2	Kinder Morgan Canada	Terminals	Total
Balance as of December 31, 2007	$ 263.2	$ 288.4	$ 46.1	$ 251.0	$ 229.1	$ 1,077.8
Acquisitions and purchase price adjs.	—	—	—	—	27.8	27.8
Disposals.	—	—	—	—	—	—
Impairments	—	—	—	—	—	—
Currency translation adjustments	—	—	—	(17.9)	—	(17.9)
Balance as of September 30, 2008	$ 263.2	$ 288.4	$ 46.1	$ 233.1	$ 256.9	$ 1,087.7

Pursuant to our adoption of SFAS No. 142, "Goodwill and Other Intangible Assets" on January 1, 2002, we selected a goodwill impairment measurement date of January 1 of each year; and we have determined that our goodwill was not impaired as of January 1, 2008. In the second quarter of 2008, we changed our impairment measurement date to May 31 of each year. The change was made following our management's decision to match our impairment testing date to the impairment testing date of Knight—following the completion of its going-private transaction on May 30, 2007, Knight established as its goodwill impairment measurement date May 31 of each year. This change to the date of our annual goodwill impairment test constitutes a change in the method of applying an accounting principle, as discussed in paragraph 4 of SFAS No. 154, "Accounting Changes and Error Corrections." We believe that this change in accounting principle is preferable because our test would then be performed at the same time as Knight, which indirectly owns all the common stock of our general partner.

SFAS No. 154 requires an entity to report a change in accounting principle through retrospective application of the new accounting principle to all periods, unless it is impracticable to do so. However, our change to a new testing date, when applied to prior periods, does not yield different financial statement results. Furthermore, there were no impairment charges resulting from the May 31, 2008 impairment testing, and no event indicating an impairment has occurred subsequent to that date.

In addition, according to the provisions of Accounting Principles Board Opinion No. 18, "The Equity Method of Accounting for Investments in Common Stock," we identify any premium or excess cost we pay over our proportionate share of the underlying fair value of net assets acquired and accounted for as investments under the equity method of accounting. This premium or excess cost is referred to as equity method goodwill and is not subject to amortization but rather to periodic impairment testing. As of both September 30, 2008 and December 31, 2007, we have reported$138.2 million in equity method goodwill within the caption "Investments" in our accompanying consolidated balance sheets.

Other Intangibles

Excluding goodwill, our other intangible assets include customer relationships, contracts and agreements, technology-based assets, and lease value. These intangible assets have definite lives, are being amortized on a straight-line basis over their estimated useful lives, and are reported separately as “Other intangibles, net” in our accompanying consolidated balance sheets. Following is information related to our intangible assets subject to amortization (in millions):

	September 30, 2008	December 31, 2007
Customer relationships, contracts and agreements		
Gross carrying amount	$ 246.0	$ 264.1
Accumulated amortization	(47.5)	(36.9)
Net carrying amount	198.5	227.2
Technology-based assets, lease value and other		
Gross carrying amount	13.3	13.3
Accumulated amortization	(2.3)	(1.9)
Net carrying amount	11.0	11.4
Total Other intangibles, net	$ 209.5	$ 238.6

The decrease in the carrying amount of customer relationships, contracts and agreements since December 31, 2007 was primarily due to purchase price adjustments related to the fair value of an intangible customer contract included in our purchase of certain assets from Marine Terminals, Inc. on September 1, 2007. For more information on this acquisition, see Note 2 “Acquisitions and Joint Ventures—Acquisitions from Unrelated Entities—Marine Terminals, Inc. Assets.”

For the three and nine months ended September 30, 2008, the amortization expense on our intangibles totaled $3.8 million and $11.0 million, respectively, and for the same prior year periods, the amortization expense on our intangibles totaled $3.6 million and $10.4 million, respectively. These expense amounts primarily consisted of amortization of our customer relationships, contracts and agreements. As of September 30, 2008, the weighted average amortization period for our intangible assets was approximately 17.5 years. Our estimated amortization expense for these assets for each of the next five fiscal years (2009 – 2013) is approximately $13.8 million, $13.6 million, $13.4 million, $13.1 million and $13.1 million, respectively.

7. Debt

Our outstanding short-term debt as of September 30, 2008 was $284.7 million. The balance consisted of (i) $250.0 million in principal amount of 6.30% senior notes due February 1, 2009; (ii) $18.5 million in principal amount of tax-exempt bonds due April 1, 2024 (our subsidiary Kinder Morgan Operating L.P. “B” is the obligor on the bonds and the bonds are due on demand pursuant to call provisions); (iii) a $9.7 million portion of a 5.40% long-term note payable (our subsidiaries Kinder Morgan Operating L.P. “A” and Kinder Morgan Canada Company are the obligors on the note); and (iv) a $6.5 million portion of 5.23% senior notes (our subsidiary, Kinder Morgan Texas Pipeline, L.P., is the obligor on the notes). The weighted average interest rate on all of our borrowings was approximately 5.30% during the third quarter of 2008 and approximately 6.47% during the third quarter of 2007. For the first nine months of 2008 and 2007, the weighted average interest rate on all of our borrowings was approximately 5.46% and 6.45%, respectively.

Credit Facility

Our $1.85 billion five-year unsecured bank credit facility matures August 18, 2010 and can be amended to allow for borrowings up to $2.1 billion. Borrowings under our credit facility can be used for partnership purposes and as a backup for our commercial paper program. The outstanding balance under our five-year credit facility was $295.0 million as of September 30, 2008. As of December 31, 2007, there were no borrowings under the credit facility.

Our five-year credit facility is with a syndicate of financial institutions, and Wachovia Bank, National Association is the administrative agent. On September 15, 2008, Lehman Brothers Holdings Inc.

filed for bankruptcy protection under the provisions of Chapter 11 of the U.S. Bankruptcy Code. No Lehman Brothers affiliate is an administrative agent for us or any of our subsidiaries; however, one of the Lehman entities is a lending bank providing less than 5% of the commitments in our bank credit facility. Since Lehman Brothers declared bankruptcy, its affiliate which is a party to our credit facility has not met its obligations to lend under that agreement. Thus, it is likely that the available capacity of our facility will be reduced by the Lehman commitment. The commitments of the other banks remain unchanged, and the facility is not defaulted.

As of September 30, 2008, the amount available for borrowing under our credit facility was reduced by an aggregate amount of $681.5 million, consisting of (i) a combined $375 million in three letters of credit that support our hedging of commodity price risks associated with the sale of natural gas, natural gas liquids and crude oil; (ii) a $100 million letter of credit that supports certain proceedings with the California Public Utilities Commission involving refined products tariff charges on the intrastate common carrier operations of our Pacific operations' pipelines in the state of California; (iii) a combined $86.9 million in three letters of credit that support tax-exempt bonds; (iv) a combined $55.9 million in letters of credit that support our pipeline and terminal operations in Canada; (v) a $26.8 million letter of credit that supports our indemnification obligations on the Series D note borrowings of Cortez Capital Corporation; (vi) a $19.9 million letter of credit that supports the construction of our Kinder Morgan Louisiana Pipeline (a natural gas pipeline); and (vii) a combined $17 million in other letters of credit supporting other obligations of us and our subsidiaries.

Commercial Paper Program

Our commercial paper program provides for the issuance of up to $1.85 billion of commercial paper. Our $1.85 billion unsecured five-year bank credit facility supports our commercial paper program, and borrowings under our commercial paper program reduce the borrowings allowed under our credit facility. As of September 30, 2008, we had no outstanding commercial paper borrowings. On October 13, 2008, Standard & Poor's Rating Services lowered our short-term credit rating to A-3 from A-2. As a result of this revision and current commercial paper market conditions, we are currently unable to access commercial paper borrowings. However, we expect that our financing and liquidity needs will continue to be met through borrowings made under our bank credit facility described above.

As of December 31, 2007, we had $589.1 million of commercial paper outstanding with an average interest rate of 5.58%. The borrowings under our commercial paper program were used principally to finance the acquisitions and capital expansions we made during 2007.

Senior Notes

On February 12, 2008, we completed a public offering of senior notes. We issued a total of $900 million in principal amount of senior notes, consisting of $600 million of 5.95% notes due February 15, 2018, and $300 million of 6.95% notes due January 15, 2038. We received proceeds from the issuance of the notes, after underwriting discounts and commissions, of approximately $894.1 million, and we used the proceeds to reduce the borrowings under our commercial paper program. The notes due in 2038 constitute a further issuance of the $550 million aggregate principal amount of 6.95% notes we issued on June 21, 2007 and form a single series with those notes.

On June 6, 2008, we completed an additional public offering of senior notes. We issued a total of $700 million in principal amount of senior notes, consisting of $375 million of 5.95% notes due February 15, 2018, and $325 million of 6.95% notes due January 15, 2038. We received proceeds from the issuance of the notes, after underwriting discounts and commissions, of approximately $687.7 million, and we used the proceeds to reduce the borrowings under our commercial paper program. The notes due in 2018 constitute a further issuance of the $600 million aggregate principal amount of 5.95% notes we issued on February 12, 2008 and form a single series with those notes. The notes due in 2038 constitute a further issuance of the combined $850 million aggregate principal amount of 6.95% notes we issued on June 21, 2007 and February 12, 2008 and form a single series with those notes.

Kinder Morgan Operating L.P. "A" Debt

As part of the purchase price consideration for our January 1, 2007 acquisition of the remaining approximately 50.2% interest in the Cochin pipeline system that we did not already own, two of our subsidiaries issued a long-term

note payable to the seller having a fair value of $42.3 million. We valued the debt equal to the present value of amounts to be paid, determined using an annual interest rate of 5.40%. The principal amount of the note, along with interest, is due in five equal annual installments of $10.0 million on March 31 in each of 2008, 2009, 2010, 2011 and 2012. Our subsidiaries Kinder Morgan Operating L.P. "A" and Kinder Morgan Canada Company are the obligors on the note, and as of September 30, 2008 and December 31, 2007, the outstanding balance under the note was $36.1 million and $44.6 million, respectively.

Central Florida Pipeline LLC Debt

On July 23, 2008, Central Florida Pipeline LLC paid $5.0 million to retire the outstanding principal amount of its 7.84% senior notes that matured on that date.

Kinder Morgan Operating L.P. "B" Debt

As of December 31, 2007, our subsidiary Kinder Morgan Operating L.P. "B" was the obligor of a principal amount of $23.7 million of tax-exempt bonds due April 1, 2024. The bonds were issued by the Jackson-Union Counties Regional Port District, a political subdivision embracing the territories of Jackson County and Union County in the state of Illinois. These variable rate demand bonds bear interest at a weekly floating market rate and as of December 31, 2007, we had an outstanding letter of credit issued by Wachovia in the amount of $24.1 million that backed-up the $23.7 million principal amount of the bonds and $0.4 million of accrued interest.

In September 2008, pursuant to the standby purchase agreement provisions contained in the bond indenture—which require the sellers of those guarantees to buy the debt back—certain investors elected to put (sell) back their bonds at par plus accrued interest. A total principal and interest amount of $5.2 million was tendered and drawn against our letter of credit and accordingly, we paid this amount pursuant to the letter of credit reimbursement provisions. As of September 30, 2008, our outstanding balance under the bonds was $18.5 million, and the interest rate on these bonds was 9.65%. Our outstanding letter of credit issued by Wachovia totaled $18.9 million, which backs-up the $18.5 million principal amount of the bonds and $0.4 million of interest on the bonds for up to 55 days computed at 12% per annum on the principal amount thereof. In October 2008, an additional principal amount of $0.6 million was tendered and drawn against our letter of credit and we paid this amount pursuant to the letter of credit reimbursement provisions.

Interest Rate Swaps

Information on our interest rate swaps is contained in Note 10.

Contingent Debt

As prescribed by the provisions of Financial Accounting Standards Board Interpretation (FIN) No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others," we disclose certain types of guarantees or indemnifications we have made. These disclosures cover certain types of guarantees included within debt agreements, even if the likelihood of requiring our performance under such guarantee is remote. The following is a description of our contingent debt agreements as of September 30, 2008.

Cortez Pipeline Company Debt

Pursuant to a certain Throughput and Deficiency Agreement, the partners of Cortez Pipeline Company (Kinder Morgan CO_2 Company, L.P. – 50% partner; a subsidiary of Exxon Mobil Corporation – 37% partner; and Cortez Vickers Pipeline Company – 13% partner) are required, on a several, proportional percentage ownership basis, to contribute capital to Cortez Pipeline Company in the event of a cash deficiency. Furthermore, due to our indirect ownership of Cortez Pipeline Company through Kinder Morgan CO_2 Company, L.P., we severally guarantee 50% of the debt of Cortez Capital Corporation, a wholly-owned subsidiary of Cortez Pipeline Company.

As of September 30, 2008, the debt facilities of Cortez Capital Corporation consisted of (i) $53.6 million of Series D notes due May 15, 2013; (ii) a $125 million short-term commercial paper program; and (iii) a $125 million

five-year committed revolving credit facility due December 22, 2009 (to support the above-mentioned $125 million commercial paper program). As of September 30, 2008, Cortez Capital Corporation had $40.0 million of commercial paper outstanding with an average interest rate of approximately 2.90%. The average interest rate on the Series D notes was 7.14%, and there were outstanding borrowings of $67.0 million under the five-year credit facility as of September 30, 2008.

In October 2008, Standard & Poor's Rating Services lowered Cortez Capital Corporation's short-term credit rating to A-3 from A-2. As a result of this revision and current commercial paper market conditions, Cortez is unable to access commercial paper borrowings; however, it expects that its financing and liquidity needs will continue to be met through borrowings made under its long-term bank credit facility.

With respect to Cortez's Series D notes, Shell Oil Company shares our several guaranty obligations jointly and severally; however, we are obligated to indemnify Shell for liabilities it incurs in connection with such guaranty. As of September 30, 2008, JP Morgan Chase has issued a letter of credit on our behalf in the amount of $26.8 million to secure our indemnification obligations to Shell for 50% of the $53.6 million in principal amount of Series D notes outstanding as of September 30, 2008.

Nassau County, Florida Ocean Highway and Port Authority Debt

We have posted a letter of credit as security for borrowings under Adjustable Demand Revenue Bonds issued by the Nassau County, Florida Ocean Highway and Port Authority. The bonds were issued for the purpose of constructing certain port improvements located in Fernandino Beach, Nassau County, Florida. Our subsidiary, Nassau Terminals LLC is the operator of the marine port facilities. The bond indenture is for 30 years and allows the bonds to remain outstanding until December 1, 2020. Principal payments on the bonds are made on the first of December each year and corresponding reductions are made to the letter of credit. As of September 30, 2008, this letter of credit had a face amount of $22.5 million.

In October 2008, pursuant to the standby purchase agreement provisions contained in the bond indenture—which require the sellers of those guarantees to buy the debt back—certain investors elected to put (sell) back their bonds at par plus accrued interest. A total principal and interest amount of $11.8 million was tendered and drawn against our letter of credit and accordingly, we paid this amount pursuant to the letter of credit reimbursement provisions. This payment reduced the face amount of our letter of credit from $22.5 million to $10.7 million. The remarketing agent is attempting to re-sell the bonds that were put back. If any of these bonds are re-sold, we will receive the proceeds and our letter of credit obligation will increase by the same amount.

Rockies Express Pipeline LLC Debt

Pursuant to certain guaranty agreements, all three member owners of West2East Pipeline LLC (which owns all of the member interests in Rockies Express Pipeline LLC) have agreed to guarantee, severally in the same proportion as their percentage ownership of the member interests in West2East Pipeline LLC, borrowings under Rockies Express'(i) $2.0 billion five-year, unsecured revolving credit facility due April 28, 2011; (ii) $2.0 billion commercial paper program; and (iii) $600 million in principal amount of floating rate senior notes due August 20, 2009. The three member owners and their respective ownership interests consist of the following: our subsidiary Kinder Morgan W2E Pipeline LLC – 51%, a subsidiary of Sempra Energy – 25%, and a subsidiary of ConocoPhillips – 24%.

Borrowings under the Rockies Express commercial paper program are primarily used to finance the construction of the Rockies Express interstate natural gas pipeline and to pay related expenses. The credit facility, which can be amended to allow for borrowings up to $2.5 billion, supports borrowings under the commercial paper program, and borrowings under the commercial paper program reduce the borrowings allowed under the credit facility. The $600 million in principal amount of senior notes were issued on September 20, 2007. The notes are unsecured and are not redeemable prior to maturity. Interest on the notes is paid and computed quarterly at an interest rate of three-month LIBOR (with a floor of 4.25%) plus a spread of 0.85%.

Upon issuance of the notes, Rockies Express entered into two floating-to-fixed interest rate swap agreements having a combined notional principal amount of $600 million and maturity dates of August 20, 2009. On September 24, 2008, Rockies Express terminated one of the aforementioned interest rate swaps that had Lehman Brothers as the counterparty. The notional principal amount of the terminated swap agreement was $300 million. The remaining

interest rate swap agreement effectively converts the interest expense associated with $300 million of these senior notes from its stated variable rate to a fixed rate of 5.47%.

As of September 30, 2008, in addition to the $600 million in floating rate senior notes, Rockies Express Pipeline LLC had $406.7 million of commercial paper outstanding (with a weighted average interest rate of approximately 3.58%), and outstanding borrowings of $447.5 million under its five-year credit facility. Accordingly, as of September 30, 2008, our contingent share of Rockies Express' debt was $741.6 million (51% of total guaranteed borrowings). In addition, there is a letter of credit outstanding to support the construction of the Rockies Express Pipeline. As of September 30, 2008, this letter of credit, issued by JPMorgan Chase, had a face amount of $31.4 million. Our contingent responsibility with regard to this outstanding letter of credit was $16.0 million (51% of total face amount).

No Lehman Brothers affiliate is an administrative agent for Rockies Express; however, one of the Lehman entities is a lending bank providing less than 5% of Rockies Express' $2.0 billion credit facility. Since Lehman Brothers declared bankruptcy, its affiliate which is a party to the Rockies Express credit facility has not met its obligations to lend under that agreement. Thus, it is likely that the available capacity of Rockies Express' facility will be reduced by the Lehman commitment. The commitments of the other banks remain unchanged and the facility is not defaulted.

In October 2008, Standard & Poor's Rating Services lowered Rockies Express Pipeline LLC's short-term credit rating to A-3 from A-2. As a result of this revision and current commercial paper market conditions, Rockies Express is unable to access commercial paper borrowings; however, it expects that its financing and liquidity needs will continue to be met through borrowings made under its long-term bank credit facility and contributions by its equity investors.

Midcontinent Express Pipeline LLC Debt

Pursuant to certain guaranty agreements, each of the two member owners of Midcontinent Express Pipeline LLC have agreed to guarantee, severally in the same proportion as their percentage ownership of the member interests in Midcontinent Express Pipeline LLC, borrowings under Midcontinent's $1.4 billion three-year, unsecured revolving credit facility, entered into on February 29, 2008 and due February 28, 2011. The facility is with a syndicate of financial institutions with The Royal Bank of Scotland plc as the administrative agent. Borrowings under the credit agreement will be used to finance the construction of the Midcontinent Express Pipeline system and to pay related expenses. No Lehman Brothers affiliate is an administrative agent for Midcontinent Express; however, one of the Lehman entities is a lending bank providing less than 10% of Midcontinent Express' $1.4 billion credit facility. Since Lehman Brothers declared bankruptcy, its affiliate which is a party to the Midcontinent Express credit facility has not met its obligations to lend under that agreement. Thus, it is likely that the available capacity of Midcontinent Express' facility will be reduced by the Lehman commitment. The commitments of the other banks remain unchanged and the facility is not defaulted.

Midcontinent Express Pipeline LLC is an equity method investee of ours, and the two member owners and their respective ownership interests consist of the following: our subsidiary Kinder Morgan Operating L.P. "A" – 50%, and Energy Transfer Partners, L.P. – 50%. As of September 30, 2008, Midcontinent Express Pipeline LLC had $525.0 million borrowed under its three-year credit facility. Accordingly, as of September 30, 2008, our contingent share of Midcontinent Express' debt was $262.5 million (50% of total borrowings). Furthermore, the revolving credit facility can be used for the issuance of letters of credit to support the construction of the Midcontinent Express Pipeline, and as of September 30, 2008, a letter of credit having a face amount of $33.3 million was issued under the credit facility. Accordingly, as of September 30, 2008, our contingent responsibility with regard to this outstanding letter of credit was $16.7 million (50% of total face amount).

In addition, on September 4, 2007, Midcontinent Express Pipeline LLC entered into a $197 million reimbursement agreement with JPMorgan Chase as the administrative agent. The agreement included covenants and required payments of fees that are common in such arrangements, and both we and Energy Transfer Partners, L.P. agreed to guarantee borrowings under the reimbursement agreement in the same proportion as the associated percentage ownership of Midcontinent Express' member interests. This reimbursement agreement expired on September 3, 2008.

For additional information regarding our debt facilities and our contingent debt agreements, see Note 9 to our consolidated financial statements included in our 2007 Form 10-K.

8. Partners' Capital

Limited Partner Units

As of September 30, 2008 and December 31, 2007, our partners' capital included the following limited partner units:

	September 30, 2008	December 31, 2007
Common units	179,069,427	170,220,396
Class B units	5,313,400	5,313,400
i-units	76,351,015	72,432,482
Total limited partner units	260,733,842	247,966,278

The total limited partner units represent our limited partners' interest and an effective 98% economic interest in us, exclusive of our general partner's incentive distribution rights. Our general partner has an effective 2% interest in us, excluding its incentive distribution rights.

As of September 30, 2008, our total common units consisted of 162,698,999 units held by third parties, 14,646,428 units held by Knight and its consolidated affiliates (excluding our general partner), and 1,724,000 units held by our general partner. As of December 31, 2007, our common unit total consisted of 155,864,661 units held by third parties, 12,631,735 units held by Knight and its consolidated affiliates (excluding our general partner) and 1,724,000 units held by our general partner.

On both September 30, 2008 and December 31, 2007, all of our 5,313,400 Class B units were held by a wholly-owned subsidiary of Knight. The Class B units are similar to our common units except that they are not eligible for trading on the New York Stock Exchange. All of our Class B units were issued to a wholly-owned subsidiary of Knight in December 2000.

On both September 30, 2008 and December 31, 2007, all of our i-units were held by KMR. Our i-units are a separate class of limited partner interests in us and are not publicly traded. The number of i-units we distribute to KMR is based upon the amount of cash we distribute to the owners of our common units. When cash is paid to the holders of our common units, we issue additional i-units to KMR. The fraction of an i-unit paid per i-unit owned by KMR will have a value based on the cash payment on the common unit. Based on the preceding, KMR received a distribution of 1,359,153 i-units from us on August 14, 2008, based on the $0.99 per unit distributed to our common unitholders on that date.

Equity Issuances

On February 12, 2008, we completed an offering of 1,080,000 of our common units at a price of $55.65 per unit in a privately negotiated transaction. We received net proceeds of $60.1 million for the issuance of these 1,080,000 common units, and we used the proceeds to reduce the borrowings under our commercial paper program.

On March 3, 2008, we issued, in a public offering, 5,000,000 of our common units at a price of $57.70 per unit, less commissions and underwriting expenses. At the time of the offering, we granted the underwriters a 30-day option to purchase up to an additional 750,000 common units from us on the same terms and conditions, and pursuant to this option, we issued an additional 750,000 common units on March 10, 2008 upon exercise of this option. After commissions and underwriting expenses, we received net proceeds of $324.2 million for the issuance of these 5,750,000 common units, and we used the proceeds to reduce the borrowings under our commercial paper program.

In connection with our August 28, 2008 acquisition of Knight's 33 1/3% ownership interest in the Express pipeline system and Knight's full ownership of the Jet Fuel pipeline system, we issued 2,014,693 of our common units to Knight. The units were issued August 28, 2008, and as agreed between Knight and us, were valued at $116.0 million. For more information on this acquisition, see Note 2.

Income Allocation and Declared Distributions

For the purposes of maintaining partner capital accounts, our partnership agreement specifies that items of income and loss shall be allocated among the partners, other than owners of i-units, in accordance with their percentage interests. Normal allocations according to percentage interests are made, however, only after giving effect to any priority income allocations in an amount equal to the incentive distributions that are allocated 100% to our general partner. Incentive distributions are generally defined as all cash distributions paid to our general partner that are in excess of 2% of the aggregate value of cash and i-units being distributed.

Incentive distributions allocated to our general partner are determined by the amount quarterly distributions to unitholders exceed certain specified target levels. Our distribution of $0.99 per unit paid on August 14, 2008 for the second quarter of 2008 required an incentive distribution to our general partner of $194.2 million. Our distribution of $0.85 per unit paid on August 14, 2007 for the second quarter of 2007 resulted in an incentive distribution payment to our general partner in the amount of $147.6 million. The increased incentive distribution to our general partner paid for the second quarter of 2008 over the incentive distribution paid for the second quarter of 2007 reflects the increase in the amount distributed per unit as well as the issuance of additional units.

Our declared distribution for the third quarter of 2008 of $1.02 per unit will result in an incentive distribution to our general partner of $204.3 million. This compares to our distribution of $0.88 per unit and incentive distribution to our general partner of $155.2 million for the third quarter of 2007.

9. Comprehensive Income

Comprehensive income is the change in our Partners' Capital that results from periodic revenues, expenses, gains and losses, as well as any other recognized changes that occur for reasons other than investments by and distributions to our partners. The difference between our comprehensive income and our net income represents our other comprehensive income.

For each of the three and nine month periods ended September 30, 2008 and 2007, the components of our other comprehensive income included (i) unrealized gains or losses on energy commodity derivative contracts utilized for hedging purposes; (ii) foreign currency translation adjustments; and (iii) unrealized gains or losses related to changes in pension and other post-retirement benefit plan liabilities.

Our total comprehensive income was as follows (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
Net Income:	$ 329.8	$ 213.8	$ 1,038.7	$ 297.0
Other comprehensive income (loss):				
Change in fair value of derivative contracts utilized for hedging purposes	1,291.0	(111.6)	(760.5)	(338.5)
Reclassification of change in fair value of derivative contracts to net income	201.7	94.5	624.3	258.6
Foreign currency translation adjustments	(69.6)	71.6	(113.0)	123.3
Adjustments to pension and other post-retirement benefit plan actuarial gains/losses; and reclassifications of pension and other post-retirement benefit plan actuarial gains/losses, transition obligations and prior service costs/credits to net income, net of tax	0.7	(1.0)	4.1	0.1
Total other comprehensive income (loss)	1,423.8	53.5	(245.1)	43.5
Comprehensive income	$ 1,753.6	$ 267.3	$ 793.6	$ 340.5

10. Risk Management

Energy Commodity Price Risk Management

We are exposed to risks associated with unfavorable changes in the market price of natural gas, natural gas liquids and crude oil as a result of our expected future purchase or sale of these products. Such changes are often caused by shifts in the supply and demand for these commodities, as well as their locations. Our energy commodity derivative contracts act as a hedging (offset) mechanism against the volatility of energy commodity prices by allowing us to transfer some of this price risk to counterparties who are able and willing to bear it.

Discontinuance of Hedge Accounting

Effective at the beginning of the second quarter of 2008, we determined that the derivative contracts of our Casper and Douglas natural gas processing operations that previously had been designated as cash flow hedges for accounting purposes no longer met the hedged item shared risk exposure requirement and hedge effectiveness assessment as required by SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended. Consequently, we discontinued hedge accounting treatment for these relationships (primarily crude oil hedges of heavy natural gas liquids sales) for financial reporting purposes at that time.

Pursuant to the provisions of SFAS No. 133, if a derivative contract accounted for as a cash flow hedge is discontinued because it is probable that the original forecasted transaction will not occur, any gains and losses on the derivative contracts that are included in accumulated other comprehensive income (an equity account) would be recognized immediately in net income; however, when the variability of future cash flows of the hedged item will occur as expected (as future transactions), gains and losses that are accumulated in other comprehensive income are not affected. The reason for continuing the deferral of the derivative gains and losses is that the risk of the variability of future cash flows of the hedged item is not eliminated when the cash flow hedge is discontinued.

Accordingly, since the forecasted sales of natural gas liquids volumes (the hedged item) are still expected to occur, all of our accumulated gains and losses through March 31, 2008 on the related derivative contracts remained in our accumulated other comprehensive income balance, and these gains and losses will not be reclassified into our earnings until the physical transaction occurs (similar to our accounting before our de-designation of these derivative contracts as hedge instruments). We did, however, recognize a combined expense of $0.9 million in the second and third quarters of 2008 related to our Casper and Douglas natural gas processing operations, because we had discontinued hedge accounting for these derivative contracts as of March 31, 2008 and accordingly were required to immediately recognize the unfavorable differential between (i) the delivery location, commodity and pricing specifications of the derivative contracts; and (ii) the delivery location, commodity and pricing specifications of our previously forecasted natural gas liquids sales.

Hedging effectiveness and ineffectiveness

Reflecting the portion of changes in the value of derivative contracts that were not effective in offsetting underlying changes in expected cash flows (the ineffective portion of hedges), we recognized a loss of $2.4 million during the first quarter of 2008, but no gains or losses from ineffective hedging during the second or third quarters of 2008. For the three and nine months ended September 30, 2007, we recognized a loss of $0.1 million and a gain of $0.8 million, respectively, from ineffective hedging. These recognized gains and losses resulting from hedge ineffectiveness are reported within the captions "Natural gas sales," "Gas purchases and other costs of sales," and "Product sales and other" in our accompanying consolidated statements of income, and for each of the first nine months of 2008 and 2007, we did not exclude any component of the derivative contracts' gain or loss from the assessment of hedge effectiveness.

Furthermore, during the three and nine month periods ended September 30, 2008, we reclassified $201.7 million and $624.3 million, respectively, of "Accumulated other comprehensive loss" into earnings, and for the same comparable periods last year, we reclassified $94.5 million and $258.6 million, respectively into earnings. Included in the first quarter of 2007 was approximately $0.1 million resulting from the discontinuance of cash flow hedges, due to a determination that the forecasted transactions would no longer occur by the end of the originally specified time period or within an additional two-month period of time thereafter. All remaining amounts reclassified into net income during the first nine months of both years resulted from the hedged forecasted transactions actually affecting earnings (for example, when the forecasted sales and purchases actually occurred). The proceeds or payments resulting from the settlement of cash flow hedges are reflected in the operating section of our statement of cash flows as changes to net income and working capital.

Our consolidated “Accumulated other comprehensive loss” balance was $1,521.7 million as of September 30, 2008, and $1,276.6 million as of December 31, 2007. These consolidated totals included “Accumulated other comprehensive loss” amounts associated with commodity price risk management activities of $1,515.2 million as of September 30, 2008 and $1,377.2 million as of December 31, 2007. Approximately $567.0 million of the total amount associated with our commodity price risk management activities as of September 30, 2008 is expected to be reclassified into earnings during the next twelve months (when the associated forecasted sales and purchases are also expected to occur).

Fair Value of Energy Commodity Derivative Contracts

Derivative contracts that are entered into for the purpose of mitigating commodity price risk include swaps, futures and options. Additionally, basis swaps may also be used in connection with another derivative contract to reduce hedge ineffectiveness by reducing a basis difference between a hedged exposure and a derivative contract. The fair values of these derivative contracts reflect the amounts that we would receive or pay to terminate the contracts at the reporting date, and are included in our accompanying consolidated balance sheets within “Other current assets,” “Deferred charges and other assets,” “Accrued other current liabilities,” and “Other long-term liabilities and deferred credits.”

The following table summarizes the fair values of our energy commodity derivative contracts associated with our commodity price risk management activities and included on our accompanying consolidated balance sheets as of September 30, 2008 and December 31, 2007 (in millions):

	September 30, 2008	December 31, 2007
Derivatives-net asset/(liability)		
Other current assets	$ 36.9	$ 37.0
Deferred charges and other assets	49.3	4.4
Accrued other current liabilities	(611.6)	(593.9)
Other long-term liabilities and deferred credits	$ (1,007.2)	$ (836.8)

Additional information on the fair value measurements of our energy commodity derivative contracts is included below in “—SFAS No. 157.”

Interest Rate Risk Management

In order to maintain a cost effective capital structure, it is our policy to borrow funds using a mix of fixed rate debt and variable rate debt. We use interest rate swap agreements to manage the interest rate risk associated with the fair value of our fixed rate borrowings and to effectively convert a portion of the underlying cash flows related to our long-term fixed rate debt securities into variable rate cash flows in order to achieve our desired mix of fixed and variable rate debt.

Since the fair value of fixed rate debt varies inversely with changes in the market rate of interest, we enter into swap agreements to receive a fixed and pay a variable rate of interest in order to convert the interest expense associated with certain of our senior notes from fixed rates to floating rates, resulting in future cash flows that vary with the market rate of interest. These swaps, therefore, hedge against changes in the fair value of our fixed rate debt that result from market interest rate changes.

As of December 31, 2007, we were a party to interest rate swap agreements with a total notional principal amount of $2.3 billion. On February 12, 2008, following our issuance of $600 million of 5.95% senior notes on that date, we entered into two additional fixed-to-floating interest rate swap agreements having a combined notional principal amount of $500 million; and on June 6, 2008, following our issuance of $700 million in principal amount

of senior notes in two separate series on that date (discussed in Note 7), we entered into two additional fixed-to-floating interest rate swap agreements having a combined notional principal amount of $700 million.

Therefore, as of September 30, 2008, we had a combined notional principal amount of $3.5 billion of fixed-to-floating interest rate swap agreements effectively converting the interest expense associated with certain series of our senior notes from fixed rates to variable rates based on an interest rate of LIBOR plus a spread. All of our swap agreements have termination dates that correspond to the maturity dates of the related series of senior notes and, as of September 30, 2008, the maximum length of time over which we have hedged a portion of our exposure to the variability in the value of this debt due to interest rate risk is through January 15, 2038.

Hedging effectiveness and ineffectiveness

Our interest rate swap contracts have been designated as fair value hedges and meet the conditions required to assume no ineffectiveness under SFAS No. 133, “Accounting for Derivative Instruments and Hedging Activities.” Therefore, we have accounted for them using the “shortcut” method prescribed by SFAS No. 133 and accordingly, we adjust the carrying value of each swap contract to its fair value each quarter, with an offsetting entry to adjust the carrying value of the debt securities whose fair value is being hedged. We record interest expense equal to the variable rate payments under the swap contracts.

Fair Value of Interest Rate Swap Agreements

The differences between the fair value and the original carrying value associated with our interest rate swap agreements, that is, the derivative contracts’ changes in fair value, are included within “Deferred charges and other assets” and “Other long-term liabilities and deferred credits” in our accompanying consolidated balance sheets. The offsetting entry to adjust the carrying value of the debt securities whose fair value was being hedged is included within “Value of interest rate swaps” on our accompanying consolidated balance sheets, which also includes any unamortized portion of proceeds received from the early termination of interest rate swap agreements. As of September 30, 2008, this unamortized premium totaled $13.8 million.

The following table summarizes the net fair value of our interest rate swap agreements associated with our interest rate risk management activities and included on our accompanying consolidated balance sheets as of September 30, 2008 and December 31, 2007 (in millions):

	September 30, 2008	**December 31, 2007**
Derivatives-net asset/(liability)		
Deferred charges and other assets	$ 210.7	$ 138.0
Other long-term liabilities and deferred credits	(11.5)	—
Net fair value of interest rate swaps	$ 199.2	$ 138.0

Additional information on the fair value measurements of our interest rate swap agreements is included below in “—SFAS No. 157.”

SFAS No. 157

On September 15, 2006, the FASB issued SFAS No. 157, “Fair Value Measurements.” In general, fair value measurements and disclosures are made in accordance with the provisions of this Statement and, while not requiring material new fair value measurements, SFAS No. 157 established a single definition of fair value in generally accepted accounting principles and expanded disclosures about fair value measurements. The provisions of this Statement apply to other accounting pronouncements that require or permit fair value measurements; the Financial Accounting Standards Board having previously concluded in those accounting pronouncements that fair value is the relevant measurement attribute. On February 12, 2008, the FASB issued FASB Staff Position FAS 157-2, “Effective Date of FASB Statement No. 157,” referred to as FAS 157-2 in this report. FAS 157-2 delayed the effective date of SFAS No. 157 for all nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually).

Accordingly, we have not applied the provisions of SFAS No. 157 to (i) nonfinancial assets and liabilities initially measured at fair value in business combinations; (ii) reporting units or nonfinancial assets and liabilities measured at fair value in conjunction with goodwill impairment testing; (iii) other nonfinancial assets measured at fair value in conjunction with impairment assessments; and (iv) asset retirement obligations initially measured at fair value, although the fair value measurements we have made in these circumstances are not necessarily different from those that would be made had the provisions of SFAS No. 157 been applied. We adopted the remainder of SFAS No. 157 effective January 1, 2008, and the adoption did not have a material impact on our balance sheet, statement of income, or statement of cash flows since we already apply its basic concepts in measuring fair values.

On October 10, 2008, the FASB issued FASB Staff Position FAS 157-3, “Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active,” referred to as FAS 157-3 in this report. FAS 157-3 provides clarification regarding the application of SFAS 157 in inactive markets. The provisions of FAS 157-3 are effective immediately. This Staff Position did not have any material effect on our consolidated financial statements.

The degree of judgment utilized in measuring the fair value of financial instruments generally correlates to the level of pricing observability. Pricing observability is affected by a number of factors, including the type of financial instrument, whether the financial instrument is new to the market and the characteristics specific to the transaction. Financial instruments with readily available active quoted prices or for which fair value can be measured from actively quoted prices generally will have a higher degree of pricing observability and a lesser degree of judgment utilized in measuring fair value. Conversely, financial instruments rarely traded or not quoted will generally have less (or no) pricing observability and a higher degree of judgment utilized in measuring fair value.

SFAS No. 157 established a hierarchal disclosure framework associated with the level of pricing observability utilized in measuring fair value. This framework defined three levels of inputs to the fair value measurement process, and requires that each fair value measurement be assigned to a level corresponding to the lowest level input that is significant to the fair value measurement in its entirety. The three broad levels of inputs defined by the SFAS No. 157 hierarchy are as follows:

- Level 1 Inputs—quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date;
- Level 2 Inputs—inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. If the asset or liability has a specified (contractual) term, a Level 2 input must be observable for substantially the full term of the asset or liability; and
- Level 3 Inputs—unobservable inputs for the asset or liability. These unobservable inputs reflect the entity’s own assumptions about the assumptions that market participants would use in pricing the asset or liability, and are developed based on the best information available in the circumstances (which might include the reporting entity’s own data).

Derivative contracts can be exchange-traded or over-the-counter, referred to in this report as OTC. Exchange-traded derivative contracts typically fall within Level 1 of the fair value hierarchy if they are traded in an active market. We value exchange-traded derivative contracts using quoted market prices for identical securities.

OTC derivative contracts are valued using models utilizing a variety of inputs including contractual terms; commodity, interest rate and foreign currency curves; and measures of volatility. The selection of a particular model and particular inputs to value an OTC derivative contract depends upon the contractual terms of the instrument as well as the availability of pricing information in the market. We use similar models to value similar instruments. For OTC derivative contracts that trade in liquid markets, such as generic forwards and swaps, model inputs can generally be verified and model selection does not involve significant management judgment. Such contracts are typically classified within Level 2 of the fair value hierarchy.

Certain OTC derivative contracts trade in less liquid markets with limited pricing information, and the determination of fair value for these derivative contracts is inherently more difficult. Such contracts are classified within Level 3 of the fair value hierarchy. The valuations of these less liquid OTC derivative contracts are typically

impacted by Level 1 and/or Level 2 inputs that can be observed in the market, as well as unobservable Level 3 inputs. Use of a different valuation model or different valuation input values could produce a significantly different estimate of fair value. However, derivative contracts valued using inputs unobservable in active markets are generally not material to our financial statements.

When appropriate, valuations are adjusted for various factors including credit considerations. Such adjustments are generally based on available market evidence. In the absence of such evidence, management's best estimate is used. Our fair value measurements of derivative contracts are adjusted for credit risk in accordance with SFAS No. 157, and as of September 30, 2008, our consolidated "Accumulated other comprehensive loss" balance includes a gain of $14.1 million related to discounting the value of our energy commodity derivative liabilities for the effect of credit risk.

The following tables summarize the fair value measurements of our (i) energy commodity derivative contracts; and (ii) interest rate swap agreements as of September 30, 2008, based on the three levels established by SFAS No. 157, and does not include cash margin deposits, which are reported as "Restricted deposits" in our accompanying consolidated balance sheets (in millions):

	Asset Fair Value Measurements as of September 30, 2008 Using			
	Total	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
Energy commodity derivative contracts(a)	$ 86.2	$ 1.8	$ 31.8	$ 52.6
Interest rate swap agreements	210.7	—	210.7	—

	Liability Fair Value Measurements as of September 30, 2008 Using			
	Total	**Quoted Prices in Active Markets for Identical Liabilities (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
Energy commodity derivative contracts(b)	$ (1,618.8)	$ (0.1)	$ (1,485.5)	$ (133.2)
Interest rate swap agreements	(11.5)	—	(11.5)	—

(a) Level 2 consists primarily of OTC West Texas Intermediate hedges. Level 3 consists primarily of West Texas Sour hedges and West Texas Intermediate options.

(b) Level 1 consists primarily of NYMEX Natural Gas futures. Level 2 consists primarily of OTC West Texas Intermediate hedges. Level 3 consists primarily of West Texas Sour hedges and West Texas Intermediate options.

The table below provides a summary of changes in the fair value of our Level 3 energy commodity derivative contracts for the three and nine months ended September 30, 2008 (in millions):

Significant Unobservable Inputs (Level 3)	**Three Months Ended September 30, 2008**	**Nine Months Ended September 30, 2008**
Derivatives-net asset/(liability)		
Beginning of Period	$ (233.0)	$ (100.3)
Realized and unrealized net losses	133.4	(52.9)
Purchases and settlements	19.0	72.6
Transfers in (out) of Level 3	—	—
End of Period	$ (80.6)	$ (80.6)

Change in unrealized net losses relating to contracts still held as of September 30, 2008	$ 138.5	$ (22.3)

Credit Risks

As discussed in our financial statements included in our 2007 Form 10-K, we have counterparty credit risk as a result of our use of financial derivative contracts. Our counterparties consist primarily of financial institutions, major energy companies and local distribution companies. This concentration of counterparties may impact our overall exposure to credit risk, either positively or negatively in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions.

We maintain credit policies with regard to our counterparties that we believe minimize our overall credit risk. These policies include (i) an evaluation of potential counterparties' financial condition (including credit ratings); (ii) collateral requirements under certain circumstances; and (iii) the use of standardized agreements which allow for netting of positive and negative exposure associated with a single counterparty. Based on our policies, exposure, credit and other reserves, our management does not anticipate a material adverse effect on our financial position, results of operations, or cash flows as a result of counterparty performance.

Our over-the-counter swaps and options are entered into with counterparties outside central trading organizations such as a futures, options or stock exchange. These contracts are with a number of parties, all of which have investment grade credit ratings. While we enter into derivative transactions principally with investment grade counterparties and actively monitor their ratings, it is nevertheless possible that from time to time losses will result from counterparty credit risk in the future.

In addition, in conjunction with the purchase of exchange-traded derivative contracts or when the market value of our derivative contracts with specific counterparties exceeds established limits, we are required to provide collateral to our counterparties, which may include posting letters of credit or placing cash in margin accounts. As of September 30, 2008 and December 31, 2007, we had three outstanding letters of credit totaling $375.0 million and $298.0 million, respectively, in support of our hedging of commodity price risks associated with the sale of natural gas, natural gas liquids and crude oil. Additionally, as of September 30, 2008 and December 31, 2007, we had cash margin deposits associated with our commodity contract positions and over-the-counter swap partners totaling $27.6 million and $67.9 million, respectively, and we reported these amounts as "Restricted deposits" in our accompanying consolidated balance sheets.

We are also exposed to credit related losses in the event of nonperformance by counterparties to our interest rate swap agreements, and while we enter into these agreements primarily with investment grade counterparties and actively monitor their credit ratings, it is nevertheless possible that from time to time losses will result from counterparty credit risk in the future. As of September 30, 2008, all of our interest rate swap agreements were with counterparties with investment grade credit ratings. Of the $210.7 million interest rate swap derivative asset at September 30, 2008, $92.2 million and $70.1 million of this value related to open positions with Citigroup and Merrill Lynch, respectively.

Other

Additionally, certain of our business activities expose us to foreign currency fluctuations. However, due to the limited size of this exposure, we do not believe the risks associated with changes in foreign currency will have a material adverse effect on our business, financial position, results of operations or cash flows. As a result, we do not significantly hedge our exposure to fluctuations in foreign currency.

For a more complete discussion of our risk management activities, see Note 14 to our consolidated financial statements included in our 2007 Form 10-K.

11. Reportable Segments

We divide our operations into five reportable business segments:

- Products Pipelines;
- Natural Gas Pipelines;

- CO_2;
- Terminals; and
- Kinder Morgan Canada

We evaluate performance principally based on each segments' earnings before depreciation, depletion and amortization, which excludes general and administrative expenses, third-party debt costs and interest expense, unallocable interest income and income tax expense, and minority interest. Our reportable segments are strategic business units that offer different products and services. Each segment is managed separately because each segment involves different products and marketing strategies.

Our Products Pipelines segment derives its revenues primarily from the transportation and terminaling of refined petroleum products, including gasoline, diesel fuel, jet fuel and natural gas liquids. Our Natural Gas Pipelines segment derives its revenues primarily from the sale, transport, processing, treating, storage and gathering of natural gas. Our CO_2 segment derives its revenues primarily from the production and sale of crude oil from fields in the Permian Basin of West Texas and from the transportation and marketing of carbon dioxide used as a flooding medium for recovering crude oil from mature oil fields. Our Terminals segment derives its revenues primarily from the transloading and storing of refined petroleum products and dry and liquid bulk products, including coal, petroleum coke, cement, alumina, salt and other bulk chemicals. Our Kinder Morgan Canada business segment derives its revenues primarily from the transportation of crude oil and refined products from Edmonton, Alberta to marketing terminals and refineries in the Greater Vancouver area and Puget Sound in Washington State.

As discussed in Note 2, due to the October 2007 sale of our North System, an approximately 1,600-mile interstate common carrier pipeline system whose operating results were included as part of our Products Pipelines business segment, we accounted for the North System business as a discontinued operation. Consistent with the management approach of identifying and reporting discrete financial information on operating segments, we have included the North System's financial results within our Products Pipelines business segment disclosures presented in this report for the first nine months of 2007 and, as prescribed by SFAS No. 131, we have reconciled the total of our reportable segment's financial results to our consolidated financial results by separately identifying, in the following pages where applicable, the North System amounts as discontinued operations.

Financial information by segment follows (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	**2007**	**2008**	**2007**
Revenues				
Products Pipelines				
Revenues from external customers	$ 205.6	$ 217.0	$ 602.5	$ 642.4
Intersegment revenues	—	—	—	—
Natural Gas Pipelines				
Revenues from external customers	2,359.4	1,526.8	6,916.6	4,755.3
Intersegment revenues	—	—	—	—
CO_2				
Revenues from external customers	305.2	210.6	900.2	601.7
Intersegment revenues	—	—	—	—
Terminals				
Revenues from external customers	306.0	247.1	886.4	690.8
Intersegment revenues	0.2	0.1	0.7	0.5
Kinder Morgan Canada				
Revenues from external customers	56.6	43.7	143.1	119.8
Intersegment revenues	—	—	—	—
Total segment revenues	3,233.0	2,245.3	9,449.5	6,810.5
Less: Total intersegment revenues	(0.2)	(0.1)	(0.7)	(0.5)
	3,232.8	2,245.2	9,448.8	6,810.0
Less: Discontinued operations	—	(14.4)	—	(41.1)

Total consolidated revenues	$	3,232.8	$	2,230.8	$	9,448.8	$	6,768.9

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
Operating expenses(a)				
Products Pipelines	$ 78.7	$ 84.2	$ 209.6	$ 234.4
Natural Gas Pipelines	2,203.3	1,387.8	6,464.0	4,348.9
CO_2	105.4	75.8	292.7	222.6
Terminals	175.1	158.0	483.9	390.9
Kinder Morgan Canada	18.6	19.3	51.3	47.2
Total segment operating expenses	2,581.1	1,725.1	7,501.5	5,244.0
Less: Total intersegment operating expenses	(0.2)	(0.1)	(0.7)	(0.5)
	2,580.9	1,725.0	7,500.8	5,243.5
Less: Discontinued operations	—	(4.1)	—	(14.8)
Total consolidated operating expenses	$ 2,580.9	$ 1,720.9	$ 7,500.8	$ 5,228.7
Other expense (income)				
Products Pipelines	$ 0.1	$ (0.6)	$ (0.9)	$ (2.9)
Natural Gas Pipelines	—	(0.4)	(2.7)	(3.1)
CO_2	—	—	—	—
Terminals	4.0	(1.5)	3.6	(5.9)
Kinder Morgan Canada	—	—	—	—
Total other expense (income)	4.1	(2.5)	—	(11.9)
Kinder Morgan Canada(b)	—	—	—	377.1
Total segment other expense (income)	4.1	(2.5)	—	365.2
Less: Discontinued operations	—	—	1.3	—
Total consolidated other expense (income)	$ 4.1	$ (2.5)	$ 1.3	$ 365.2
Depreciation, depletion and amortization				
Products Pipelines	$ 22.2	$ 23.0	$ 66.7	$ 67.8
Natural Gas Pipelines	17.4	16.3	50.9	48.5
CO_2	88.7	73.1	259.4	213.2
Terminals	31.0	22.2	90.9	63.9
Kinder Morgan Canada	7.5	5.7	22.6	15.4
Total segment depreciation, depletion and amortization	166.8	140.3	490.5	408.8
Less: Discontinued operations	—	(2.3)	—	(7.0)
Total consol. depreciation, depletion and amortization	$ 166.8	$ 138.0	$ 490.5	$ 401.8
Earnings from equity investments				
Products Pipelines	$ 5.0	$ 8.0	$ 21.2	$ 24.4
Natural Gas Pipelines	25.6	4.0	80.4	14.2
CO_2	4.2	4.1	15.3	14.3
Terminals	0.7	0.3	2.4	0.3
Kinder Morgan Canada	(0.9)	—	(0.8)	—
Total segment earnings from equity investments	34.6	16.4	118.5	53.2
Less: Discontinued operations	—	(0.6)	—	(1.8)
Total consolidated equity earnings	$ 34.6	$ 15.8	$ 118.5	$ 51.4

Amortization of excess cost of equity investments				
Products Pipelines	$ 0.8	$ 0.9	$ 2.5	$ 2.5
Natural Gas Pipelines	0.1	—	0.3	0.3
CO_2	0.5	0.5	1.5	1.5
Terminals	—	—	—	—
Kinder Morgan Canada	—	—	—	—
Total segment amortization of excess cost of investments	1.4	1.4	4.3	4.3
Less: Discontinued operations	—	—	—	—
Total consol. amortization of excess cost of investments	$ 1.4	$ 1.4	$ 4.3	$ 4.3
Interest income				
Products Pipelines	$ 1.1	$ 1.1	$ 3.2	$ 3.3
Natural Gas Pipelines	—	—	—	—
CO_2	—	—	—	—
Terminals	—	—	—	—
Kinder Morgan Canada	1.1	—	1.1	—
Total segment interest income	2.2	1.1	4.3	3.3
Unallocated interest income	—	0.3	0.4	0.8
Total consolidated interest income	$ 2.2	$ 1.4	$ 4.7	$ 4.1

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
Other, net – income (expense)				
Products Pipelines	$ (0.7)	$ 1.8	$ (1.0)	$ 4.9
Natural Gas Pipelines	3.9	—	21.8	0.2
CO_2	—	—	(0.2)	—
Terminals	(1.3)	0.3	1.4	0.3
Kinder Morgan Canada	2.4	2.9	8.5	4.0
Total segment other, net – income (expense)	4.3	5.0	30.5	9.4
Less: Discontinued operations	—	—	—	—
Total consolidated other, net – income (expense)	$ 4.3	$ 5.0	$ 30.5	$ 9.4
Income tax benefit (expense)				
Products Pipelines	$ (1.8)	$ (6.4)	$ (8.5)	$ (14.8)
Natural Gas Pipelines	(0.6)	(1.4)	(1.8)	(2.6)
CO_2	(0.7)	(0.9)	(2.9)	(1.1)
Terminals	(6.4)	(6.9)	(17.1)	(11.9)
Kinder Morgan Canada	(1.0)	(5.2)	2.6	(6.0)
Total segment income tax benefit (expense)	(10.5)	(20.8)	(27.7)	(36.4)
Unallocated income tax benefit (expense)	(3.7)	—	(8.1)	—
Total consolidated income tax benefit (expense)	$ (14.2)	$ (20.8)	$ (35.8)	$ (36.4)
Segment earnings before depreciation, depletion, amortization and amortization of excess cost of equity investments(c)				
Products Pipelines	$ 130.4	$ 137.9	$ 408.7	$ 428.7
Natural Gas Pipelines	185.0	142.0	555.7	421.3
CO_2	203.3	138.0	619.7	392.3
Terminals	120.1	84.4	386.3	295.0
Kinder Morgan Canada	39.6	22.1	103.2	(306.5)
Total segment earnings before DD&A	678.4	524.4	2,073.6	1,230.8
Total segment depreciation, depletion and amortization	(166.8)	(140.3)	(490.5)	(408.8)
Total segment amortization of excess cost of investments	(1.4)	(1.4)	(4.3)	(4.3)
General and administrative expenses	(73.1)	(63.0)	(222.7)	(222.7)
Interest and other non-operating expenses(d)	(107.3)	(105.9)	(317.4)	(298.0)
Total consolidated net income	$ 329.8	$ 213.8	$ 1,038.7	$ 297.0
Capital expenditures				
Products Pipelines	$ 46.6	$ 68.1	$ 167.4	$ 170.9
Natural Gas Pipelines	280.8	63.7	697.6	162.8
CO_2	135.8	111.7	384.2	273.4
Terminals	105.4	139.0	346.0	350.8
Kinder Morgan Canada	83.2	70.0	319.2	185.0
Total consolidated capital expenditures(e)	$ 651.8	$ 452.5	$ 1,914.4	$ 1,142.9

	September 30, 2008	December 31, 2007

Assets				
Products Pipelines	$	4,152.7	$	4,045.0
Natural Gas Pipelines		5,173.4		4,347.3
CO_2		2,255.8		2,004.5
Terminals		3,302.2		3,036.4
Kinder Morgan Canada		1,803.5		1,440.8
Total segment assets		16,687.6		14,874.0
Corporate assets(f)		351.3		303.8
Total consolidated assets	$	17,038.9	$	15,177.8

(a) Includes natural gas purchases and other costs of sales, operations and maintenance expenses, fuel and power expenses and taxes, other than income taxes.

(b) Nine month 2007 amount represents an expense of $377.1 million attributable to a goodwill impairment charge recognized by Knight, as discussed in Notes 2 and 6.

(c) Includes revenues, earnings from equity investments, allocable interest income, and other, net, less operating expenses, allocable income taxes, and other expense (income).

(d) Includes unallocated interest income and income tax expense, interest and debt expense and minority interest expense.

(e) Sustaining capital expenditures, including our share of Rockies Express' sustaining capital expenditures, totaled $43.3 million for the third quarter of 2008, $31.8 million for the third quarter of 2007, $120.1 million for the first nine months of 2008 and $95.0 million for the first nine months of 2007. These listed amounts do not include sustaining capital expenditures for the Trans Mountain Pipeline (part of Kinder Morgan Canada) for any periods prior to our acquisition date of April 30, 2007. Sustaining capital expenditures are defined as capital expenditures which do not increase the capacity of an asset.

(f) Includes cash and cash equivalents, margin and restricted deposits, certain unallocable deferred charges, and risk management assets related to the fair value of interest rate swaps.

We do not attribute interest and debt expense to any of our reportable business segments. For the three months ended September 30, 2008 and 2007, we reported total consolidated interest expense of $100.5 million and $103.8 million, respectively. For the nine months ended September 30, 2008 and 2007, we reported total consolidated interest expense of $298.5 million and $294.4 million, respectively.

12. Pensions and Other Post-Retirement Benefits

Due to our acquisition of the Trans Mountain pipeline system (see Note 2), Kinder Morgan Canada Inc. and Trans Mountain Pipeline Inc. (as general partner of Trans Mountain Pipeline L.P.) are sponsors of pension and other post-retirement benefit plans for eligible Trans Mountain employees. The plans include registered defined benefit pension plans, supplemental unfunded arrangements, which provide pension benefits in excess of statutory limits, and defined contributory plans. We also provide post-retirement benefits other than pensions for retired employees. Our combined net periodic benefit costs for these Trans Mountain pension and post-retirement benefit plans for the first nine months of 2008 and 2007 were approximately $2.3 million and $3.2 million, respectively. As of September 30, 2008, we estimate our overall net periodic pension and post-retirement benefit costs for these plans for the year 2008 will be approximately $3.1 million, recognized ratably over the year, although this estimate could change if there is a significant event, such as a plan amendment or a plan curtailment, which would require a remeasurement of liabilities. We expect to contribute approximately $2.6 million to these benefit plans in 2008.

Additionally, in connection with our acquisition of SFPP, L.P. and Kinder Morgan Bulk Terminals, Inc. in 1998, we acquired certain liabilities for pension and post-retirement benefits. We provide medical and life insurance benefits to current employees, their covered dependents and beneficiaries of SFPP and Kinder Morgan Bulk Terminals. We also provide the same benefits to former salaried employees of SFPP. Additionally, we will continue to fund these costs for those employees currently in the plan during their retirement years. SFPP's post-retirement benefit plan is frozen and no additional participants may join the plan.

As of September 30, 2008, we estimate no overall net periodic post-retirement benefit cost for the SFPP post-retirement benefit plan for the year 2008; however, this estimate could change if a future significant event would require a remeasurement of liabilities. For the first nine months of 2007, our net periodic benefit cost for the SFPP post-retirement benefit plan was a credit of approximately $0.2 million. The credit resulted in increases to income, largely due to amortizations of an actuarial gain and a negative prior service cost. In addition, we expect to contribute approximately $0.4 million to this post-retirement benefit plan in 2008.

The noncontributory defined benefit pension plan covering the former employees of Kinder Morgan Bulk Terminals is the Knight Inc. Retirement Plan. The benefits under this plan are based primarily upon years of service and final average pensionable earnings; however, benefit accruals were frozen as of December 31, 1998.

13. Related Party Transactions

Plantation Pipe Line Company Note Receivable

We have a seven-year note receivable bearing interest at the rate of 4.72% per annum from Plantation Pipe Line Company, our 51.17%-owned equity investee. The outstanding note receivable balance was $88.5 million as of September 30, 2008, and $89.7 million as of December 31, 2007. Of these amounts, $2.5 million and $2.4 million were included within "Accounts, notes and interest receivable, net─Related parties," as of September 30, 2008 and

December 31, 2007, respectively, and the remainder was included within “Notes receivable─Related parties” at each reporting date.

Express US Holdings LP Note Receivable

In conjunction with the acquisition of our 33 1/3% equity ownership interest in the Express pipeline system (discussed in Note 2) from Knight on August 28, 2008, we acquired a long-term investment in a debt security issued by Express US Holdings LP (the obligor), the partnership that maintains ownership of the U.S. portion of the Express pipeline system. As of our acquisition date, the value of this unsecured debenture was equal to Knight’s carrying value of $107.0 million. The note is denominated in Canadian dollars, and the principal amount of the note is $113.6 million Canadian dollars, due in full on January 9, 2023. It bears interest at the rate of 12.0% per annum and provides for quarterly payments of interest in Canadian dollars on March 31, June 30, September 30 and December 31 each year.

As of September 30, 2008, the outstanding note receivable balance, representing the translated amount included in our consolidated financial statements in U.S. dollars, was$106.7 million, and we included this amount within “Notes receivable─Related parties” on our accompanying consolidated balance sheet.

Knight Note Receivable

As of December 31, 2007, an affiliate of Knight owed to us a long-term note with a principal amount of $0.6 million, and we included this balance within “Notes receivable─Related parties” on our consolidated balance sheet as of that date. The note had no fixed terms of repayment and was denominated in Canadian dollars. In each of the second and third quarters of 2008, we received payments of $0.3 million in principal amount under this note, and as of September 30, 2008, there was no outstanding balance due under this note. The above amounts represent translated amounts in U.S. dollars.

Knight Asset Contributions

In conjunction with our acquisition of (i) certain Natural Gas Pipelines assets and partnership interests from Knight in December 1999 and December 2000; and (ii) all of the partnership interest in TransColorado Gas Transmission Company from two wholly-owned subsidiaries of Knight on November 1, 2004, Knight agreed to indemnify us and Kinder Morgan G.P., Inc. with respect to approximately $733.5 million of our debt. Knight would be obligated to perform under this indemnity only if we are unable and/or our assets were insufficient to satisfy our obligations.

Fair Value of Energy Commodity Derivative Contracts

As a result of the May 2007 going-private transaction of Knight, as discussed in Note 1, a number of individuals and entities became significant investors in Knight. By virtue of the size of their ownership interest in Knight, two of those investors became “related parties” to us (as that term is defined in authoritative accounting literature): (i) American International Group, Inc., referred to in this report as AIG, and certain of its affiliates; and (ii) Goldman Sachs Capital Partners and certain of its affiliates.

We and/or our affiliates enter into transactions with certain AIG affiliates in the ordinary course of their conducting insurance and insurance-related activities, although no individual transaction is, and all such transactions collectively are not, material to our consolidated financial statements. We also conduct commodity risk management activities in the ordinary course of implementing our risk management strategies in which the counterparty to certain of our derivative transactions is an affiliate of Goldman Sachs. In conjunction with these activities, we are a party (through one of our subsidiaries engaged in the production of crude oil) to a hedging facility with J. Aron & Company/Goldman Sachs which requires us to provide certain periodic information, but does not require the posting of margin. As a result of changes in the market value of our derivative positions, we have created both amounts receivable from and payable to Goldman Sachs affiliates.

The following table summarizes the fair values of our energy commodity derivative contracts that are (i) associated with commodity price risk management activities with related parties; and (ii) included on our accompanying consolidated balance sheets as of September 30, 2008 and December 31, 2007 (in millions):

	September 30, 2008	December 31, 2007
Derivatives-net asset/(liability)		
Deferred charges and other assets	$ 13.6	$ —
Accrued other current liabilities	(256.3)	(239.8)
Other long-term liabilities and deferred credits	$ (594.2)	$ (386.5)

Other

Generally, KMR makes all decisions relating to the management and control of our business. Our general partner owns all of KMR's voting securities and is its sole managing member. Knight, through its wholly owned and controlled subsidiary Kinder Morgan (Delaware), Inc., owns all the common stock of our general partner. Certain conflicts of interest could arise as a result of the relationships among KMR, our general partner, Knight and us; however, the audit committee of KMR's board of directors will, at the request of KMR, review (and is one of the means for resolving) conflicts of interest that may arise between Knight or its subsidiaries, on the one hand, and us, on the other hand. For a more complete discussion of our related-party transactions, see Note 12 to our consolidated financial statements included in our 2007 Form 10-K.

14. Regulatory Matters

The following updates the disclosure in Note 17 to our audited financial statements that were filed with our 2007 Form 10-K with respect to developments that occurred during the nine months ended September 30, 2008.

FERC Order No. 2004/690/717

Since November 2003, the FERC issued Orders No. 2004, 2004-A, 2004-B, 2004-C, and 2004-D, adopting new Standards of Conduct as applied to natural gas pipelines. The primary change from existing regulation was to make such standards applicable to an interstate natural gas pipeline's interaction with many more affiliates (referred to as "energy affiliates"). The Standards of Conduct require, among other things, separate staffing of interstate pipelines and their energy affiliates (but support functions and senior management at the central corporate level may be shared) and strict limitations on communications from an interstate pipeline to an energy affiliate.

However, on November 17, 2006, the United States Court of Appeals for the District of Columbia Circuit, in Docket No. 04-1183, vacated FERC Orders 2004, 2004-A, 2004-B, 2004-C, and 2004-D as applied to natural gas pipelines, and remanded these same orders back to the FERC.

On January 9, 2007, the FERC issued an Interim Rule, effective January 9, 2007, in response to the court's action. In the Interim Rule, the FERC readopted the Standards of Conduct, but revised or clarified with respect to issues which had been appealed to the court. Specifically, the following changes were made:

- the Standards of Conduct apply only to the relationship between interstate gas transmission pipelines and their marketing affiliates, not their energy affiliates;
- all risk management personnel can be shared;
- the requirement to post discretionary tariff actions was eliminated (but interstate gas pipelines must still maintain a log of discretionary tariff waivers);
- lawyers providing legal advice may be shared employees; and
- new interstate gas transmission pipelines are not subject to the Standards of Conduct until they commence service.

The FERC clarified that all exemptions and waivers issued under Order No. 2004 remain in effect. On January 18, 2007, the FERC issued a notice of proposed rulemaking, referred to in this report as a NOPR, seeking comments regarding whether or not the Interim Rule should be made permanent for natural gas transmission providers. On March 21, 2007, the FERC issued an Order on Clarification and Rehearing of the Interim Rule that granted clarification that the Standards of Conduct only apply to natural gas transmission providers that are affiliated with a marketing or brokering entity that conducts transportation transactions on such gas transmission provider's pipeline.

On March 21, 2008, as part of an effort to undertake a broader review of the existing Standards of Conduct, the FERC issued a new notice of proposed rulemaking revamping the Standards of Conduct in order to make compliance and enforcement easier, rather than issuing a Final Rule on the January 18 NOPR. The intent of this action is to return to the core principles of the original Standards of Conduct, which established a functional separation between transmission and merchant personnel for natural gas and electric transmission providers. The new NOPR is made up of three rules: (i) independent functioning of transmission function employees from marketing function employees; (ii) the no-conduit rule prohibiting the passing and receipt of non-public transmission information; (iii) and the transparency rule to detect undue discrimination. On October 16, 2008, the FERC issued a Final Rule in Order 717 revising the FERC Standards of Conduct for natural gas and electric transmission providers by eliminating Order No. 2004's concept of Energy Affiliates and corporate separation in favor of an employee functional approach as used in Order No. 497. A transmission provider is prohibited from disclosing to a marketing function employee non-public information about the transmission system or a transmission customer. The final rule also retains the long-standing no-conduit rule, which prohibits a transmission function provider from disclosing non-public information to marketing function employees by using a third party conduit. Additionally, the final rule requires that a transmission provider provide annual training on the Standards of Conduct to all transmission function employees, marketing function employees, officers, directors, supervisory employees, and any other employees likely to become privy to transmission function information. This rule will become effective on November 26, 2008.

Notice of Inquiry – Financial Reporting

On February 15, 2007, the FERC issued a notice of inquiry seeking comment on the need for changes or revisions to the FERC's reporting requirements contained in the financial forms for gas and oil pipelines and electric utilities. Initial comments were filed by numerous parties on March 27, 2007, and reply comments were filed on April 27, 2007.

On September 20, 2007, the FERC issued for public comment in Docket No. RM07-9 a proposed rule which would revise its financial forms to require that additional information be reported by natural gas companies. The proposed rule would require, among other things, that natural gas companies: (i) submit additional revenue information, including revenue from shipper-supplied gas; (ii) identify the costs associated with affiliate transactions; and (iii) provide additional information on incremental facilities and on discounted and negotiated rates. The FERC proposed an effective date of January 1, 2008, which means that forms reflecting the new requirements for 2008 would be filed in early 2009. Comments on the proposed rule were filed by numerous parties on November 13, 2007.

On March 21, 2008 the FERC issued a Final Rule regarding changes to the Form 2, 2-A and 3Q. The revisions were designed to enhance the forms' usefulness by updating them to reflect current market and cost information relevant to interstate pipelines and their customers. The rule is effective January 1, 2008 with the filing of the revised Form 3-Q beginning with the first quarter of 2009. The revised Form 2 and 2-A for calendar year 2008 material would be filed by April 30, 2009. On June 20, 2008, the FERC issued an Order Granting in Part and Denying in Part Rehearing and Granting Request for Clarification. No substantive changes were made to the March 21, 2008 Final Rule.

Notice of Inquiry – Fuel Retention Practices

On September 20, 2007, the FERC issued a Notice of Inquiry seeking comment on whether it should change its current policy and prescribe a uniform method for all interstate gas pipelines to use in recovering fuel gas and gas lost and unaccounted for. The Notice of Inquiry included numerous questions regarding fuel recovery issues and the effects of fixed fuel percentages as compared with tracking provisions. Comments on the Notice of Inquiry were filed by numerous parties on November 30, 2007.

Notice of Proposed Rulemaking – Promotion of a More Efficient Capacity Release Market-Order 712

On November 15, 2007, the FERC issued a notice of proposed rulemaking in Docket No. RM 08-1-000 regarding proposed modifications to its Part 284 regulations concerning the release of firm capacity by shippers on interstate natural gas pipelines. The FERC proposes to remove, on a permanent basis, the rate ceiling on capacity release transactions of one year or less. Additionally, the FERC proposes to exempt capacity releases made as part of an asset management arrangement from the prohibition on tying and from the bidding requirements of section 284.8. Initial comments were filed by numerous parties on January 25, 2008. On June 19, 2008, the FERC issued a final rule in Order 712 regarding changes to the capacity release program. The FERC permitted market based pricing for short-term capacity releases of a year or less. Long-term capacity releases and the pipeline's sale of its own capacity remains subject to a price cap. The ruling would facilitate asset management arrangements by relaxing the FERC's prohibitions on tying and on bidding requirements for certain capacity releases. The FERC further clarified that its prohibition on tying does not apply to conditions associated with gas inventory held in storage for releases for firm storage capacity. Finally, the FERC waived the prohibition on tying and bidding requirements for capacity releases made as part of state-approved retail open access programs. The final rule became effective on July 30, 2008.

Notice of Proposed Rulemaking – Natural Gas Price Transparency

On April 19, 2007, the FERC issued a notice of proposed rulemaking in Docket Nos. RM07-10-000 and AD06-11-000 regarding price transparency provisions of Section 23 of the Natural Gas Act and the Energy Policy Act. In the notice, the FERC proposed to revise its regulations to (i) require that intrastate pipelines post daily the capacities of, and volumes flowing through, their major receipt and delivery points and mainline segments in order to make available the information to track daily flows of natural gas throughout the United States; and (ii) require that buyers and sellers of more than a de minimis volume of natural gas report annual numbers and volumes of relevant transactions to the FERC in order to make possible an estimate of the size of the physical U.S. natural gas market, assess the importance of the use of index pricing in that market, and determine the size of the fixed-price trading market that produces the information. The FERC believes these revisions to its regulations will facilitate price transparency in markets for the sale or transportation of physical natural gas in interstate commerce. Initial comments were filed on July 11, 2007 and reply comments were filed on August 23, 2007. In addition, the FERC conducted an informal workshop in this proceeding on July 24, 2007, to discuss implementation and other technical issues associated with the proposals set forth in the NOPR.

In addition, on December 21, 2007, the FERC issued a new notice of proposed rulemaking in Docket No. RM08-2-000 regarding the daily posting provisions that were contained in Docket Nos. RM07-10-000 and AD06-11-000. The new NOPR proposes to exempt from the daily posting requirements those non-interstate pipelines that (i) flow less than ten million MMBtus of natural gas per year; (ii) fall entirely upstream of a processing plant; and (iii) deliver more than ninety-five percent (95%) of the natural gas volumes they flow directly to end-users. However, the new NOPR expands the proposal to require that both interstate and non-exempt non-interstate pipelines post daily the capacities of, volumes scheduled at, and actual volumes flowing through, their major receipt and delivery points and mainline segments. Initial comments were filed by numerous parties on March 13, 2008. A Technical Conference was held on April 3, 2008. Numerous reply comments were received on April 14, 2008.

On December 26, 2007, the FERC issued Order No. 704 in this docket implementing only the annual reporting provisions of the NOPR with minimal changes to the original proposal. The order became effective February 4, 2008. The initial report is due May 1, 2009 for calendar year 2008. Subsequent reports are due by May 1 of each year for the previous calendar year. Order 704 will require most, if not all of our natural gas pipelines to report annual volumes of relevant transactions to the FERC. Technical workshops were held on April 22, 2008 and May 19, 2008. The FERC issued Order 704-A on September 18, 2008. This order generally affirmed the rule, while clarifying what information certain natural gas market participants must report in Form 552. The revisions pertain to the reporting of transactions occurring in calendar year 2008. The first report is due May 1, 2009 and each May 1st thereafter for subsequent calendar years. Order 704-A became effective October 27, 2008.

FERC Equity Return Allowance

On April 17, 2008, the FERC adopted a new policy under Docket No. PL07-2-000 that will allow master limited partnerships to be included in proxy groups for the purpose of determining rates of return for both interstate natural gas and oil pipelines. Additionally, the policy statement concluded that (i) there should be no cap on the level of distributions included in the FERC's current discounted cash flow methodology; (ii) the Institutional Brokers Estimated System forecasts should remain the basis for the short-term growth forecast used in the discounted cash flow calculation; (iii) there should be an adjustment to the long-term growth rate used to calculate the equity cost of capital for a master limited partnership, specifically the long term growth rate would be set at 50% of the gross domestic product; and (iv) there should be no modification to the current respective two-thirds and one-third weightings of the short-term and long-term growth factors. Additionally, the FERC decided not to explore other methods for determining a pipeline's equity cost of capital at this time. The policy statement will govern all future gas and oil rate proceedings involving the establishment of a return on equity, as well as those cases that are currently pending before either the FERC or an administrative law judge. On May 19, 2008, an application for rehearing was filed by The American Public Gas Association. On June 13, 2008, the FERC dismissed the request for rehearing.

Notice of Proposed Rulemaking - Rural Onshore Low Stress Hazardous Liquids Pipelines

On September 6, 2006, the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration, referred to in this report as the PHMSA, published a notice of proposed rulemaking (PHMSA 71 FR 52504) that proposed to extend certain threat-focused pipeline safety regulations to rural onshore low-stress hazardous liquid pipelines within a prescribed buffer of previously defined U.S. states. Low-stress hazardous liquid pipelines, except those in populated areas or that cross commercially navigable waterways, have not been subject to the safety regulations in PHMSA 49 C.F.R. Part 195.1. According to the PHMSA, unusually sensitive areas are areas requiring extra protection because of the presence of sole-source drinking water resources, endangered species, or other ecological resources that could be adversely affected by accidents or leaks occurring on hazardous liquid pipelines.

The notice proposed to define a category of "regulated rural onshore low-stress lines" (rural lines operating at or below 20% of specified minimum yield strength, with a diameter of eight and five-eighths inches or greater, located in or within a quarter-mile of a U.S. state) and to require operators of these lines to comply with a threat-focused set of requirements in Part 195 that already apply to other hazardous liquid pipelines. The proposed safety requirements addressed the most common threats—corrosion and third party damage—to the integrity of these rural lines. The proposal is intended to provide additional integrity protection, to avoid significant adverse environmental consequences, and to improve public confidence in the safety of unregulated low-stress lines.

Since the new notice is a proposed rulemaking in which the PHMSA will consider initial and reply comments from industry participants, it is not clear what impact the final rule will have on the business of our intrastate and interstate pipeline companies.

Natural Gas Pipeline Expansion Filings

Rockies Express Pipeline-Currently Certificated Facilities

We own a 51% ownership interest in West2East Pipeline LLC, a limited liability company that is the sole owner of Rockies Express Pipeline LLC, and operate the Rockies Express Pipeline. ConocoPhillips owns a 24% ownership interest in West2East Pipeline LLC and Sempra Energy holds the remaining 25% interest. When construction of the entire Rockies Express Pipeline project is completed, our ownership interest will be reduced to 50% at which time the capital accounts of West2East Pipeline LLC will be trued up to reflect our 50% economics in the project. According to the provisions of current accounting standards, because we will receive 50% of the economics of the Rockies Express project on an ongoing basis, we are not considered the primary beneficiary of West2East Pipeline LLC and thus, we account for our investment under the equity method of accounting.

On August 9, 2005, the FERC approved the application of Rockies Express Pipeline LLC, formerly known as Entrega Gas Pipeline LLC, to construct 327 miles of pipeline facilities in two phases. For phase I (consisting of two pipeline segments), Rockies Express was granted authorization to construct and operate approximately 136 miles of pipeline extending northward from the Meeker Hub, located at the northern end of our TransColorado pipeline system in Rio Blanco County, Colorado, to the Wamsutter Hub in Sweetwater County, Wyoming (segment 1), and then construct approximately 191 miles of pipeline eastward to the Cheyenne Hub in Weld County, Colorado (segment 2). Construction of segments 1 and 2 has been completed, with interim service commencing on segment 1 on February 24, 2006, and full in-service of both segments on February 14, 2007. For phase II, Rockies Express was authorized to construct three compressor stations referred to as the Meeker, Big Hole and Wamsutter compressor stations. The Meeker and Wamsutter stations went into service in January 2008. Construction of the Big Hole compressor station commenced in the second quarter of 2008, and the expected in-service date for this compressor station is the second quarter of 2009.

Rockies Express Pipeline-West Project

On April 19, 2007, the FERC issued a final order approving the Rockies Express application for authorization to construct and operate certain facilities comprising its proposed “Rockies Express-West Project.” This project is the first planned segment extension of the Rockies Express’ facilities described above, and is comprised of approximately 713 miles of 42-inch diameter pipeline extending from the Cheyenne Hub to an interconnection with Panhandle Eastern Pipe Line located in Audrain County, Missouri. The project also includes certain improvements to existing Rockies Express facilities located to the west of the Cheyenne Hub. Construction on Rockies Express-West commenced on May 21, 2007, and interim service for up to 1.4 billion cubic feet per day of natural gas on the segment’s first 503 miles of pipe began on January 12, 2008. The project commenced deliveries to Panhandle Eastern Pipe Line at Audrain County, Missouri on the remaining 210 miles of pipe on May 20, 2008. The Rockies Express-West pipeline segment transports approximately 1.5 million cubic feet per day of natural gas across five states: Wyoming, Colorado, Nebraska, Kansas and Missouri.

Rockies Express replaced certain pipe to reflect a higher class location and conducted further hydrostatic testing of portions of its system during September 2008 to satisfy U.S. Department of Transportation testing requirements to operate at its targeted higher operating pressure. This pipe replacement and hydrostatic testing, conducted from September 3, 2008 through September 26, 2008, resulted in the temporary outage of pipeline delivery points and an overall reduction of firm capacity available to firm shippers. By the terms of the Rockies Express FERC Gas Tariff, firm shippers are entitled to daily reservation revenue credits for non-force majeure and planned maintenance outages. The estimated impact of these revenue credits is included in our third quarter results.

Rockies Express Pipeline-East Project

On April 30, 2007, Rockies Express filed an application with the FERC requesting a certificate of public convenience and necessity that would authorize construction and operation of the Rockies Express-East Project. The Rockies Express-East Project will be comprised of approximately 639 miles of 42-inch diameter pipeline commencing from the terminus of the Rockies Express-West pipeline to a terminus near the town of Clarington in Monroe County, Ohio and will be capable of transporting approximately 1.8 billion cubic feet per day of natural gas.

By order issued May 30, 2008, the FERC authorized the certificate to construct the Rockies Express Pipeline-East Project. Construction commenced on the Rockies Express-East pipeline segment on June 26, 2008. Delays in securing permits and regulatory approvals, as well as weather-related delays, have caused Rockies Express to set revised project completion dates. Rockies Express-East is currently projected to commence service on April 1, 2009 to interconnects upstream of Lebanon, followed by service to the Lebanon Hub in Warren County, Ohio beginning June 15, 2009, with final completion and deliveries to Clarington, Ohio commencing by November 1, 2009.

Current market conditions for consumables, labor and construction equipment along with certain provisions in the final regulatory orders have resulted in increased costs for the project and have impacted certain projected

completion dates. For example, our current estimate of total completed cost on the Rockies Express Pipeline is approximately $6.0 billion (consistent with our October 15, 2008 third quarter earnings press release).

Kinder Morgan Interstate Gas Transmission Pipeline

On August 6, 2007, Kinder Morgan Interstate Gas Transmission Pipeline, referred to in this report as KMIGT, filed, in FERC Docket CP07-430, for regulatory approval to construct and operate a 41-mile, $30 million natural gas pipeline, referred to in this report as the Colorado Lateral, from the Cheyenne Hub to markets in and around Greeley, Colorado. When completed, the Colorado Lateral will provide firm transportation of up to 55 million cubic feet per day to a local utility under long-term contract. The FERC issued a draft environmental assessment on the project on January 11, 2008, and comments on the project were received February 11, 2008. On February 21, 2008, the FERC granted the certificate application. On July 8, 2008, in response to a rehearing request by Public Service Company of Colorado, referred to in this report as PSCo, the FERC granted rehearing and denied KMIGT recovery in initial transportation rates $6.2 million in costs associated with non-jurisdictional laterals constructed by KMIGT to serve Atmos. The recourse rate adjustment is not expected to have any material effect on the negotiated rate paid by Atmos to KMIGT or the economics of the project. On July 25, 2008, KMIGT filed an amendment to its certificate application, seeking authorization to revise its initial rates for transportation service on the Colorado Lateral to reflect updated construction costs for jurisdictional mainline facilities. The FERC approved the revised initial recourse rates on August 22, 2008.

PSCo, a competitor serving markets off the Colorado Lateral, also filed a complaint before the State of Colorado Public Utilities Commission ("CoPUC") against Atmos, the anchor shipper on the project. The CoPUC conducted a hearing on April 14, 2008 on the complaint. On June 9, 2008, PSCo also filed before the CoPUC seeking a temporary cease and desist order to halt construction of the lateral facilities being constructed by KMIGT to serve Atmos. Atmos filed a response to that motion on June 24, 2008. By order dated June 27, 2008 an administrative law judge for the CoPUC denied PSCo's request for a cease and desist order. On September 4, 2008, an administrative law judge for the CoPUC issued an order wherein it denied PSCo's claim to exclusivity to serve Atmos and the Greeley market area but affirmed PSCo's claim that Atmos' acquisition of the delivery laterals is not in the ordinary course of business and requires separate approvals. Accordingly, Atmos may require a certificate of public convenience and necessity ("CPCN") to acquire the delivery lateral facilities from KMIGT. Atmos' application and approval for a CPCN is not expected to delay in-service of the facilities on or about November 7, 2008.

On December 21, 2007, KMIGT filed, in Docket CP 08-44, for approval to expand its system in Nebraska to serve incremental ethanol and industrial load. No protests to the application were filed and the project was approved by the FERC. Construction commenced on April 9, 2008. These facilities will be in service in November 2008.

Kinder Morgan Louisiana Pipeline

On September 8, 2006, in FERC Docket No. CP06-449-000, we filed an application with the FERC requesting approval to construct and operate our Kinder Morgan Louisiana Pipeline. The natural gas pipeline will extend approximately 135 miles from Cheniere's Sabine Pass liquefied natural gas terminal in Cameron Parish, Louisiana, to various delivery points in Louisiana and will provide interconnects with many other natural gas pipelines, including Natural Gas Pipeline Company of America LLC. The project is supported by fully subscribed capacity and long-term customer commitments with Chevron and Total. The entire estimated project cost is now expected to be approximately $1.0 billion (consistent with our October 15, 2008 third quarter earnings press release), and it is expected to be fully operational during the second quarter of 2009.

On March 15, 2007, the FERC issued a preliminary determination that the authorizations requested, subject to some minor modifications, will be in the public interest. This order does not consider or evaluate any of the environmental issues in this proceeding. On April 19, 2007, the FERC issued the final environmental impact statement, or EIS, which addressed the potential environmental effects of the construction and operation of the Kinder Morgan Louisiana Pipeline. The final EIS was prepared to satisfy the requirements of the National Environmental Policy Act. It concluded that approval of the Kinder Morgan Louisiana Pipeline project would have limited adverse environmental impacts. On June 22, 2007, the FERC issued an order granting construction and operation of the project. Kinder Morgan Louisiana Pipeline officially accepted the order on July 10, 2007.

On July 11, 2008, Kinder Morgan Louisiana Pipeline filed an amendment to its certificate application, seeking authorization to revise its initial rates for transportation service on the Kinder Morgan Louisiana Pipeline system to reflect updated construction costs for the project. The amendment was accepted by the FERC on August 14, 2008.

Midcontinent Express Pipeline

On October 9, 2007, in Docket No. CP08-6-000, Midcontinent Express Pipeline LLC filed an application with the FERC requesting a certificate of public convenience and necessity that would authorize construction and operation of the approximately 500-mile Midcontinent Express Pipeline natural gas transmission system.

The Midcontinent Express Pipeline will create long-haul, firm transportation takeaway capacity either directly or indirectly connected to natural gas producing regions located in Texas, Oklahoma and Arkansas. The pipeline will originate in southeastern Oklahoma and traverse east through Texas, Louisiana, Mississippi, and terminate at an interconnection with the Transco Pipeline near Butler, Alabama. The Midcontinent Express Pipeline is a 50/50 joint venture between us and Energy Transfer Partners, L.P., and it has a total capital cost of approximately $1.9 billion, including the expansion capacity (consistent with our October 15, 2008 third quarter earnings press release). Initial design capacity for the pipeline was 1.5 billion cubic feet of natural gas per day, which was fully subscribed with long-term binding commitments from creditworthy shippers. A successful binding open season was recently completed which will increase the main segment of the pipeline’s capacity to 1.8 billion cubic feet per day, subject to regulatory approval.

On July 25, 2008, the FERC approved the application made by Midcontinent Express Pipeline to construct and operate the 500-mile Midcontinent Express Pipeline natural gas transmission system along with the lease of 272 million cubic feet of capacity on the Oklahoma intrastate system of Enogex Inc. Midcontinent Express Pipeline accepted the FERC Certificate on July 30, 2008. Mobilization for construction of the pipeline began in the third quarter, and subject to the receipt of regulatory approvals, interim service on the first portion of the pipeline is expected to be available by the second quarter of 2009 with full in service in the third quarter of 2009.

Kinder Morgan Liquid Terminals

With regard to several of our liquids terminals, we are working with the U.S. Department of Transportation, referred to in this report as the DOT, to supplement our compliance program for certain of our tanks and internal piping. We anticipate the program will call for incremental capital spending over the next several years to improve and/or add to our facilities. These improvements will enhance the tanks and piping previously considered outside the jurisdiction of DOT to conduct DOT jurisdictional transfers of products. Our original estimate called for an incremental $3 million to $5 million of annual capital spending over the next six to ten years for this work; however, we continue to assess the amount of capital that will be required and the amount may exceed our original estimate.

Kinder Morgan Texas Pipeline LLC

On May 30, 2008, Kinder Morgan Texas Pipeline LLC filed in Docket No. PR08-25-000 a petition seeking market-based rate authority for firm and interruptible storage services performed under section 311 of the Natural Gas Policy Act of 1978 (NGPA) at the North Dayton Gas Storage Facility in Liberty County, Texas, and at the Markham Gas Storage Facility in Matagorda County, Texas. On October 3, 2008, FERC approved this petition effective May 30, 2008.

15. Recent Accounting Pronouncements

EITF 04-5

In June 2005, the Emerging Issues Task Force reached a consensus on Issue No. 04-5, or EITF 04-5, “Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights.” EITF 04-5 provides guidance for purposes of assessing whether certain limited partners rights might preclude a general partner from controlling a limited partnership.

For general partners of all new limited partnerships formed, and for existing limited partnerships for which the partnership agreements are modified, the guidance in EITF 04-5 is effective after June 29, 2005. For general partners in all other limited partnerships, the guidance is effective no later than the beginning of the first reporting period in fiscal years beginning after December 15, 2005 (January 1, 2006 for us). The adoption of EITF 04-5 did not have an effect on our consolidated financial statements.

Nonetheless, as a result of EITF 04-5, as of January 1, 2006, our financial statements are consolidated into the consolidated financial statements of Knight. Notwithstanding the consolidation of our financial statements into the consolidated financial statements of Knight pursuant to EITF 04-5, Knight is not liable for, and its assets are not available to satisfy, the obligations of us and/or our subsidiaries and vice versa. Responsibility for payments of obligations reflected in our or Knight's financial statements is a legal determination based on the entity that incurs the liability. The determination of responsibility for payment among entities in our consolidated group of subsidiaries was not impacted by the adoption of EITF 04-5.

FIN 48

In July 2006, the FASB issued Interpretation (FIN) No. 48, "Accounting for Uncertainty in Income Taxes—an Interpretation of FASB Statement No. 109," which became effective January 1, 2007. FIN 48 addressed the determination of how tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. Under FIN 48, we must recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based not only on the technical merits of the tax position based on tax law, but also the past administrative practices and precedents of the taxing authority. The tax benefits recognized in the financial statements from such a position are measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate resolution.

Our adoption of FIN No. 48 on January 1, 2007 did not result in a cumulative effect adjustment to "Partners' Capital" on our consolidated balance sheet. Our continuing practice is to recognize interest and/or penalties related to income tax matters in income tax expense, and as of January 1, 2007, we had $1.1 million of accrued interest and no accrued penalties. As of December 31, 2007 (i) we had $0.6 million of accrued interest and no accrued penalties; (ii) we believe it is reasonably possible that our liability for unrecognized tax benefits will decrease by approximately $1.2 million during the next twelve months; and (iii) we believe approximately $5.4 million of the total $6.3 million of unrecognized tax benefits on our consolidated balance sheet as of December 31, 2007 would affect our effective income tax rate in future periods in the event those unrecognized tax benefits were recognized.

In addition, we have U.S. and state tax years open to examination for the periods 2003 through 2007. As of September 30, 2008, there have been no material changes to our December 31, 2007 liability for unrecognized tax benefits, interest, penalties or to our estimated change in the liability during 2008.

SFAS No. 157

For information on SFAS No. 157, see Note 10 "—SFAS No. 157."

SFAS No. 159

On February 15, 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities." This Statement provides companies with an option to report selected financial assets and liabilities at fair value. The Statement's objective is to reduce both complexity in accounting for financial instruments and the volatility in earnings caused by measuring related assets and liabilities differently. The Statement also establishes presentation and disclosure requirements designed to facilitate comparisons between companies that choose different measurement attributes for similar types of assets and liabilities.

SFAS No. 159 requires companies to provide additional information that will help investors and other users of financial statements to more easily understand the effect of the company's choice to use fair value on its earnings. It also requires entities to display the fair value of those assets and liabilities for which the company has chosen to use fair value on the face of the balance sheet. The Statement does not eliminate disclosure requirements included in other accounting standards, including requirements for disclosures about fair value measurements included in SFAS No. 157 (discussed in Note 10 "—SFAS No. 157") and in SFAS No. 107 "Disclosures about Fair Value of Financial Instruments."

This Statement was adopted by us effective January 1, 2008, at which time no financial assets or liabilities, not previously required to be recorded at fair value by other authoritative literature, were designated to be recorded at fair value. As such, the adoption of this Statement did not have any impact on our consolidated financial statements.

SFAS 141(R)

On December 4, 2007, the FASB issued SFAS No. 141R (revised 2007), "Business Combinations." Although this statement amends and replaces SFAS No. 141, it retains the fundamental requirements in SFAS No. 141 that (i) the purchase method of accounting be used for all business combinations; and (ii) an acquirer be identified for each business combination. SFAS No. 141R defines the acquirer as the entity that obtains control of one or more businesses in the business combination and establishes the acquisition date as the date that the acquirer achieves control. This Statement applies to all transactions or other events in which an entity (the acquirer) obtains control of one or more businesses (the acquiree), including combinations achieved without the transfer of consideration; however, this Statement does not apply to a combination between entities or businesses under common control.

Significant provisions of SFAS No. 141R concern principles and requirements for how an acquirer (i) recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree; (ii) recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase; and (iii) determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination.

This Statement applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008 (January 1, 2009 for us). Early adoption is not permitted. We are currently reviewing the effects of this Statement.

SFAS No. 160

On December 4, 2007, the FASB issued SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements – an amendment of ARB No. 51." This Statement changes the accounting and reporting for noncontrolling interests in consolidated financial statements. A noncontrolling interest, sometimes referred to as a minority interest, is the portion of equity in a subsidiary not attributable, directly or indirectly, to a parent.

Specifically, SFAS No. 160 establishes accounting and reporting standards that require (i) the ownership interests in subsidiaries held by parties other than the parent to be clearly identified, labeled, and presented in the consolidated balance sheet within equity, but separate from the parent's equity; (ii) the equity amount of consolidated net income attributable to the parent and to the noncontrolling interest to be clearly identified and presented on the face of the consolidated income statement (consolidated net income and comprehensive income will be determined without deducting minority interest, however, earnings-per-share information will continue to be calculated on the basis of the net income attributable to the parent's shareholders); and (iii) changes in a parent's ownership interest while the parent retains its controlling financial interest in its subsidiary to be accounted for consistently and similarly—as equity transactions.

This Statement is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008 (January 1, 2009 for us). Early adoption is not permitted. SFAS No. 160 is to be applied prospectively as of the beginning of the fiscal year in which it is initially applied, except for its presentation and disclosure requirements, which are to be applied retrospectively for all periods presented. We do not anticipate that the adoption of this Statement will have a material effect on our consolidated financial statements.

SFAS No. 161

On March 19, 2008, the FASB issued SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities." This Statement amends SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" and is intended to help investors better understand how derivative instruments and hedging activities affect an entity's financial position, financial performance and cash flows through enhanced disclosure requirements. The enhanced disclosures include, among other things, (i) a tabular summary of the fair value of derivative instruments and their gains and losses; (ii) disclosure of derivative features that are credit-risk–related to provide more information regarding an entity's liquidity; and (iii) cross-referencing within footnotes to make it easier for financial statement users to locate important information about derivative instruments.

This Statement is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008 (January 1, 2009 for us). Early application is encouraged. We do not anticipate that the adoption of this Statement will have a material effect on our consolidated financial statements.

EITF 07-4

In March 2008, the Emerging Issues Task Force reached a consensus on Issue No. 07-4, or EITF 07-4, "Application of the Two-Class Method under FASB Statement No. 128, Earnings per Share, to Master Limited Partnerships." EITF 07-4 provides guidance for how current period earnings should be allocated between limited partners and a general partner when the partnership agreement contains incentive distribution rights.

This Issue is effective for fiscal years beginning after December 15, 2008 (January 1, 2009 for us), and interim periods within those fiscal years. Earlier application is not permitted, and the guidance in this Issue is to be applied retrospectively for all financial statements presented. We do not anticipate that the adoption of this Issue will have a material effect on our consolidated financial statements.

FASB Staff Position No. FAS 142-3

On April 25, 2008, the FASB issued FASB Staff Position FAS 142-3 "Determination of the Useful Life of Intangible Assets." This Staff Position amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset under SFAS No. 142, "Goodwill and Other Intangible Assets". This Staff Position is effective for financial statements issued for fiscal years beginning after December 15, 2008 (January 1, 2009 for us), and interim periods within those fiscal years. Early adoption is prohibited. We do not anticipate that the adoption of this Staff Position will have a material effect on our consolidated financial statements.

SFAS No. 162

On May 9, 2008, the FASB issued SFAS No. 162, "The Hierarchy of Generally Accepted Accounting Principles." This Statement is intended to improve financial reporting by identifying a consistent framework, or hierarchy, for selecting accounting principles to be used in preparing financial statements that are presented in conformity with U.S. generally accepted accounting principles, referred to in this note as GAAP, for nongovernmental entities.

Statement No. 162 establishes that the GAAP hierarchy should be directed to entities because it is the entity (not its auditor) that is responsible for selecting accounting principles for financial statements that are presented in conformity with GAAP. Statement No. 162 is effective 60 days following the U.S. Securities and Exchange Commission's approval of the Public Company Accounting Oversight Board Auditing amendments to AU Section 411, "The Meaning of Present Fairly in Conformity with Generally Accepted Accounting Principles," and is only effective for nongovernmental entities. We do not expect the adoption of this Statement to have any effect on our consolidated financial statements.

FASB Staff Position No. FAS 157-3

On October 10, 2008, the FASB issued FASB Staff Position FAS 157-3 “Determining the Fair Value of a Financial Asset When the Market for that Asset is Not Active.” This Staff Position provides guidance clarifying how SFAS No. 157, “Fair Value Measurements” should be applied when valuing securities in markets that are not active. This Staff Position applies the objectives and framework of SFAS No. 157 to determine the fair value of a financial asset in a market that is not active, and it reaffirms the notion of fair value as an exit price as of the measurement date. Among other things, the guidance also states that significant judgment is required in valuing financial assets. This Staff Position became effective upon issuance, and did not have any material effect on our consolidated financial statements.

Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations.

General

The following information should be read in conjunction with (i) our accompanying interim consolidated financial statements and related notes (included elsewhere in this report); and (ii) our consolidated financial statements, related notes and management’s discussion and analysis of financial condition and results of operations included in our 2007 Form 10-K.

In addition, as discussed in Note 2 to our consolidated financial statements included elsewhere in this report, our financial statements reflect:

- the April 30, 2007 transfer of the Trans Mountain pipeline system net assets from Knight as if such transfer had taken place on January 1, 2006, the effective date of common control pursuant to generally accepted accounting principles. Accordingly, we have included the financial results of the Trans Mountain pipeline system within our Kinder Morgan Canada business segment disclosures presented in this report for all periods subsequent to January 1, 2006;

- the August 28, 2008 transfer of both the 33 1/3% interest in the Express pipeline system net assets and the Jet Fuel pipeline system net assets from Knight as of the date of transfer. Accordingly, we have included the financial results of the Express and Jet Fuel pipeline systems within our Kinder Morgan Canada business segment disclosures presented in this report for all periods subsequent to August 28, 2008; and

- the reclassifications necessary to reflect the results of our North System as discontinued operations. However, because the sale of our North System does not change the structure of our internal organization in a manner that causes a change to our reportable business segments pursuant to the provisions of SFAS No. 131, “Disclosures about Segments of an Enterprise and Related Information,” we have included the North System’s financial results within our Products Pipelines business segment disclosures presented in this report for the three and nine months ended September 30, 2007.

We are an energy infrastructure owner and operator. Our principal business segments are:

- Products Pipelines—the ownership and operation of refined petroleum products pipelines that deliver gasoline, diesel fuel, jet fuel and natural gas liquids to various markets, plus the ownership and/or operation of associated product terminals and petroleum pipeline transmix facilities;

- Natural Gas Pipelines—the ownership and operation of major interstate and intrastate natural gas pipeline and storage systems;

- CO_2—(i) the production, transportation and marketing of carbon dioxide, referred to as CO_2, to oil fields that use CO_2 to increase production of oil, (ii) ownership interests in and/or operation of oil fields in West Texas, and (iii) the ownership and operation of a crude oil pipeline system in West Texas;

- Terminals—the ownership and/or operation of liquids and bulk terminal facilities and rail transloading and materials handling facilities located throughout the United States; and

- Kinder Morgan Canada—the ownership and operation of a pipeline system that transports crude oil and refined petroleum products from Edmonton, Alberta, Canada to marketing terminals and refineries in British Columbia, Canada and the state of Washington. This segment also includes the recently completed first portion of the Anchor Loop expansion of the Trans Mountain Pipeline, and the 33 1/3% interest in the Express pipeline system net assets and the Jet Fuel pipeline system net assets we acquired from Knight effective August 28, 2008. Following the acquisition of these two businesses, the operations of our Trans Mountain, Express and Jet Fuel pipeline systems have been combined to represent our "Kinder Morgan Canada" segment.

As an energy infrastructure owner and operator in multiple facets of the United States' and Canada's various energy businesses and markets, we examine a number of variables and factors on a routine basis to evaluate our current performance and our prospects for the future. Many of our operations are regulated by various U.S. and Canadian regulatory bodies. The profitability of our products pipeline transportation business is generally driven by the utilization of our facilities in relation to their capacity, as well as the prices we receive for our services. Transportation volume levels are primarily driven by the demand for the petroleum products being shipped or stored, and the prices for shipping are generally based on regulated tariffs that are adjusted annually based on changes in the U.S. Producer Price Index. Because of the overall effect of utilization on our products pipeline transportation business, we seek to own refined products pipelines located in, or that transport to, stable or growing markets and population centers.

With respect to our interstate natural gas pipelines and related storage facilities, the revenues from these assets tend to be received under contracts with terms that are fixed for various periods of time. We monitor the contracts under which we provide interstate natural gas transportation services and, to the extent practicable and economically feasible in light of our strategic plans and other factors, we generally attempt to mitigate risk of reduced volumes and prices by negotiating contracts with longer terms, with higher per-unit pricing and for a greater percentage of our available capacity. However, changes, either positive or negative, in actual quantities transported on our interstate natural gas pipelines may not accurately measure or predict associated changes in profitability because many of the underlying transportation contracts, sometimes referred to as take-or-pay contracts, specify that we receive the majority of our fee for making the capacity available, whether or not the customer actually chooses to utilize the capacity.

Our CO_2 sales and transportation business, like our natural gas pipelines business, generally has take-or-pay contracts, although the contracts in our CO_2 business typically have minimum volume requirements. In the long term, our success in this business is driven by the demand for CO_2. However, short-term changes in the demand for CO_2 typically do not have a significant impact on us due to the required minimum transport volumes under many of our contracts. In the oil and gas producing activities within our CO_2 business segment, we monitor the amount of capital we expend in relation to the amount of production that is added or the amount of declines in production that are postponed. In that regard, our production during any period and the reserves that we add during that period are important measures. In addition, the revenues we receive from our crude oil, natural gas liquids and CO_2 sales are a function of, in addition to production quantity, the prices we realize from the sale of these products. Over the long term, we will tend to receive prices that are dictated by the demand and overall market price for these products. In the shorter term, however, published market prices are likely not indicative of the revenues we will receive due to our risk management, or hedging, program in which the prices to be realized for certain of our future sales quantities are fixed, capped or bracketed through the use of financial derivative contracts, particularly for crude oil.

As with our pipeline transportation businesses, the profitability of our terminals businesses is generally driven by the utilization of our terminals facilities in relation to their capacity, as well as the prices we receive for our services, which in turn are driven by the demand for the products being shipped or stored. The extent to which changes in these variables affect our terminals businesses in the near term is a function of the length of the underlying service contracts, the extent to which revenues under the contracts are a function of the amount of product stored or transported, and the extent to which such contracts expire during any given period of time. As with our pipeline transportation businesses, we monitor the contracts under which we provide services and, to the extent practicable and economically feasible in light of our strategic plans and other factors, we generally attempt to mitigate the risk

of reduced volumes and pricing by negotiating contracts with longer terms, with higher per-unit pricing and for a greater percentage of our available capacity. In addition, weather-related factors such as hurricanes, floods and droughts may impact our facilities and access to them and, thus, the profitability of certain terminals for limited periods of time or, in relatively rare cases of severe damage to facilities, for longer periods.

In our discussions of the operating results of individual businesses which follow, we generally identify the important fluctuations between periods that are attributable to acquisitions and dispositions separately from those that are attributable to businesses owned in both periods. We believe that we have a history of making accretive acquisitions and economically advantageous expansions of existing businesses. Our ability to increase earnings and increase distributions to our unitholders will, to some extent, be a function of completing successful acquisitions and expansions. We continue to have opportunities for expansion of our facilities in many markets, and we expect to continue to have such opportunities in the future, although the level of such opportunities is difficult to predict.

Our ability to make accretive acquisitions is a function of the availability of suitable acquisition candidates and, to some extent, our ability to raise necessary capital to fund such acquisitions, factors over which we have limited or no control. The availability of suitable acquisition candidates has lessened in recent periods, largely due to prices that are not attractive to us, but we have no way to determine the extent to which we will be able to identify accretive acquisition candidates, or the number or size of such candidates in the future, or whether we will complete the acquisition of any such candidates.

In addition to any uncertainties described in this discussion and analysis, we are subject to a variety of risks that could have a material adverse effect on our business, financial condition, cash flows and results of operations. Please see Part II, Item 1A "Risk Factors" of this report for a more detailed description of these and other factors that may affect our business portfolio.

Critical Accounting Policies and Estimates

Accounting standards require information in financial statements about the risks and uncertainties inherent in significant estimates, and the application of generally accepted accounting principles involves the exercise of varying degrees of judgment. Certain amounts included in or affecting our consolidated financial statements and related disclosures must be estimated, requiring us to make certain assumptions with respect to values or conditions that cannot be known with certainty at the time the financial statements are prepared. These estimates and assumptions affect the amounts we report for our assets and liabilities, our revenues and expenses during the reporting period, and our disclosure of contingent assets and liabilities at the date of our financial statements. We routinely evaluate these estimates, utilizing historical experience, consultation with experts and other methods we consider reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from our estimates.

Further information about us and information regarding our accounting policies and estimates that we consider to be "critical" can be found in our 2007 Form 10-K. There have not been any significant changes in these policies and estimates during the nine months ended September 30, 2008; however, during the second quarter of 2008, we changed the date of our annual goodwill impairment test date to May 31 of each year. Although our change to a new testing date, when applied to prior periods, does not yield different financial statement results, this change constitutes a change in the method of applying an accounting principle, as discussed in paragraph 4 of SFAS No. 154, "Accounting Changes and Error Corrections." For more information on this change, see Note 6 to our consolidated financial statements included elsewhere in this report.

Results of Operations

Consolidated

	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Earnings Increase/(decrease)	
	(In millions, except percentages)			
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments(a)				
Products Pipelines(b)	$ 130.4	$ 137.9	$ (7.5)	(5)%
Natural Gas Pipelines(c)	185.0	142.0	43.0	30%
CO_2	203.3	138.0	65.3	47%
Terminals(d)	120.1	84.4	35.7	42%
Kinder Morgan Canada	39.6	22.1	17.5	79%
Segment earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	678.4	524.4	154.0	29%
Depreciation, depletion and amortization expense	(166.8)	(140.3)	(26.5)	(19)%
Amortization of excess cost of equity investments	(1.4)	(1.4)	—	—
General and administrative expenses(e)	(73.1)	(63.0)	(10.1)	(16)%
Interest and other non-operating expenses(f)	(107.3)	(105.9)	(1.4)	(1)%
Net income	$ 329.8	$ 213.8	$ 116.0	54%

	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007	Earnings Increase/(decrease)	
	(In millions, except percentages)			
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments(a)				
Products Pipelines(g)	$ 408.7	$ 428.7	$ (20.0)	(5)%
Natural Gas Pipelines(h)	555.7	421.3	134.4	32%
CO_2	619.7	392.3	227.4	58%
Terminals(i)	386.3	295.0	91.3	31%
Kinder Morgan Canada(j)	103.2	(306.5)	409.7	n/a
Segment earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	2,073.6	1,230.8	842.8	68%
Depreciation, depletion and amortization expense(k)	(490.5)	(408.8)	(81.7)	(20)%
Amortization of excess cost of equity investments	(4.3)	(4.3)	—	—
General and administrative expenses(l)	(222.7)	(222.7)	—	—
Interest and other non-operating expenses(m)	(317.4)	(298.0)	(19.4)	(7)%
Net income	$ 1,038.7	$ 297.0	$ 741.7	250%

(a) Includes revenues, earnings from equity investments, allocable interest income and other, net, less operating expenses, allocable income taxes, and other expense (income). Operating expenses include natural gas purchases and other costs of sales, operations and maintenance expenses, fuel and power expenses, and taxes, other than income taxes.

(b) 2008 amount includes a $9.3 million decrease in income from the proposed settlement of certain litigation matters related to our Pacific operations' East Line pipeline, a $0.7 million decrease in income resulting from unrealized foreign currency losses on long-term debt transactions, and a $0.2 million decrease in income related to hurricane clean-up and repair activities. 2007 amount includes a $15.0 million increase in expense for a litigation settlement reached with Contra Costa County, California, a $3.2 million increase in expense from the settlement of certain litigation matters related to our West Coast refined products terminal operations, and a $0.9 million increase in income resulting from unrealized foreign currency gains on long-term debt transactions.

(c) 2008 amount includes a $12.2 million increase in income resulting from unrealized mark to market gains due to the discontinuance of hedge accounting at Casper Douglas, and a $4.4 million increase in expense related to hurricane clean-up and repair activities.

(d) 2008 amount includes a $6.8 million decrease in income related to fire damage and repair activities, a $4.0 million decrease in income related to hurricane clean-up and repair activities, and a combined $1.5 million increase in expense from the settlement of certain litigation matters related to our Elizabeth River bulk terminal and our Staten Island liquids terminal. 2007 amount includes a $25.0 million increase in expense from the settlement of certain litigation matters related to our Cora coal terminal.

(e) 2008 amount includes (i) a $1.4 million increase in non-cash compensation expense, allocated to us from Knight (we do not have any obligation, nor do we expect to pay any amounts related to this expense); (ii) a $0.1 million increase in expense related to hurricane clean-up and repair activities; and (iii) a $1.5 million decrease in expense due to the adjustment of certain insurance related liabilities. 2007 amount includes (i) a $1.5 million increase in non-cash compensation expense, allocated to us from Knight (we do not have any obligation, nor do we expect to pay any amounts related to this expense); (ii) a $0.8 million increase in expense related to the cancellation of certain commercial insurance policies; and (iii) a $0.4 million increase in expense for certain Trans Mountain acquisition costs.

(f) Includes unallocated interest income and income tax expense, interest and debt expense, and minority interest expense. 2008 and 2007 amounts each include increases in imputed interest expense of $0.5 million related to our January 1, 2007 Cochin Pipeline acquisition. 2008 amount also includes a $0.2 million increase in interest expense related to the proposed settlement of certain litigation matters related to our Pacific operations' East Line pipeline. 2008 and 2007 amounts also include decreases in expense of $0.2 million and $0.4 million, respectively, related to the minority interest effect from all of the three month 2008 and 2007 items previously disclosed in these footnotes.

(g) 2008 amount includes a $9.3 million decrease in income from the proposed settlement of certain litigation matters related to our Pacific operations' East Line pipeline, a $1.4 million decrease in income resulting from unrealized foreign currency losses on long-term debt transactions, a $0.2 million decrease in income related to hurricane clean-up and repair activities, and a $1.3 million gain from the 2007 sale of our North System. 2007 amount includes a $15.0 million increase in expense for a litigation settlement reached with Contra Costa County, California, a $3.2 million increase in expense from the settlement of certain litigation matters related to our West Coast refined products terminal operations, a $2.2 million increase in expense associated with environmental liability adjustments, and a $1.7 million increase in income resulting from unrealized foreign currency gains on long-term debt transactions.

(h) 2008 amount includes a $13.0 million gain from the sale of our 25% equity ownership interest in Thunder Creek Gas Services, LLC, a $4.4 million increase in expense related to hurricane clean-up and repair activities, and a $0.9 million decrease in income resulting from unrealized mark to market losses due to the discontinuance of hedge accounting at Casper Douglas. 2007 amount includes a decrease in income of $1.0 million reflecting our portion of a loss from the early extinguishment of debt by Red Cedar Gathering Company.

(i) 2008 amount includes a $6.8 million decrease in income related to fire damage and repair activities, a $4.0 million decrease in income related to hurricane clean-up and repair activities, and a combined $1.5 million increase in expense from the settlement of certain litigation matters related to our Elizabeth River bulk terminal and our Staten Island liquids terminal. 2007 amount includes a $25.0 million increase in expense from the settlement of certain litigation matters related to our Cora coal terminal, and an increase in income of $1.8 million from property casualty gains associated with the 2005 hurricane season.

(j) 2007 amount includes losses of $349.2 million for periods prior to our acquisition date of April 30, 2007. This amount includes a $377.1 million impairment expense, associated with a non-cash reduction in the carrying value of Trans Mountain's goodwill.

(k) 2007 amount includes Trans Mountain expenses of $6.3 million for periods prior to our acquisition date of April 30, 2007.

(l) 2008 amount includes (i) a $4.2 million increase in non-cash compensation expense, allocated to us from Knight (we do not have any obligation, nor do we expect to pay any amounts related to this expense); (ii) a $0.1 million increase in expense related to hurricane clean-up and repair activities; and (iii) a $1.5 million decrease in expense due to the adjustment of certain insurance related liabilities. 2007 amount includes (i) a $24.9 million increase in non-cash compensation expense, allocated to us from Knight (we do not have any obligation, nor do we expect to pay any amounts related to this expense); (ii) a $5.5 million increase in expense from the inclusion of Trans Mountain for periods prior to our acquisition date of April 30, 2007; (iii) a $1.7 million increase in insurance expense associated with the 2005 hurricane season; (iv) a $1.5 million increase in expense for certain Trans Mountain acquisition costs; and (v) a $0.8 million increase in expense related to the cancellation of certain commercial insurance policies.

(m) 2008 and 2007 amounts include increases in imputed interest expense of $1.5 million and $1.7 million, respectively, related to our January 1, 2007 Cochin Pipeline acquisition. 2008 amount also includes a $0.2 million increase in interest expense related to the proposed settlement of certain litigation matters related to our Pacific operations' East Line pipeline. 2007 amount also includes a $1.2 million increase in interest expense from the inclusion of Trans Mountain for periods prior to our acquisition date of April 30, 2007. 2008 and 2007 amounts also include decreases in expense of $0.2 million and $3.9 million, respectively, related to the minority interest effect from all of the nine month 2008 and 2007 items previously disclosed in these footnotes.

Benefitting from higher revenues from crude oil and carbon dioxide sales, improved margins from our Texas intrastate pipeline group, the start-up of the Rockies Express-West natural gas pipeline, and incremental earnings from expanded bulk and liquids terminal operations, our consolidated net income for the quarterly period ended September 30, 2008 was $329.8 million ($0.48 per diluted limited partner unit), compared to $213.8 million ($0.24 per diluted limited partner unit) for the quarterly period ended September 30, 2007. The increase in our quarterly net income was tempered by such factors as lower gasoline demand in 2008, due to higher prices and a slowing economy, and increases in construction and fuel costs, which negatively impacted both our capital expansion programs and our existing operations in the third quarter of 2008, when compared to the prior year third quarter.

For the nine months ended September 30, 2008 and 2007, we earned net income of $1,038.7 million and $297.0 million, respectively; however, our 2007 year-to-date net income included an impairment expense of $377.1 million associated with a non-cash reduction in the carrying value of Trans Mountain's goodwill. The goodwill impairment charge was recognized by Knight in March 2007, and following our purchase of Trans Mountain from Knight on April 30, 2007, the financial results of Trans Mountain since January 1, 2006, including the impact of the goodwill impairment, are reflected in our results. For more information on this acquisition and the goodwill impairment, see Notes 2 and 6 to our consolidated financial statements included elsewhere in this report.

Because our partnership agreement requires us to distribute 100% of our available cash to our partners on a quarterly basis (available cash as defined in our partnership agreement generally consists of all our cash receipts, less cash disbursements and changes in reserves), we consider each period's earnings before all non-cash depreciation, depletion and amortization expenses, including amortization of excess cost of equity investments, to be an important measure of our success in maximizing returns to our partners. We also use segment earnings before depreciation, depletion and amortization expenses (defined in the table above and sometimes referred to in this report as EBDA) internally as a measure of profit and loss used for evaluating segment performance and for deciding how to allocate resources to our five reportable business segments.

For the third quarter of 2008, total segment earnings before depreciation, depletion and amortization increased $154.0 million (29%), when compared to the third quarter of 2007. The overall quarterly increase in total segment earnings before depreciation, depletion and amortization expenses included incremental earnings of $27.6 million from the combined net effect of the certain items described in the footnotes to the tables above. The remaining $126.4 million (22%) increase was driven by better performance from our CO_2, Natural Gas Pipelines, Terminals and Kinder Morgan Canada business segments.

For the comparable nine month periods, our total segment earnings before depreciation, depletion and amortization increased $842.8 million (68%) in 2008, when compared to 2007. The certain items described in the footnotes to the table above (including the goodwill impairment expense) accounted for $377.9 million of the overall increase, and the remaining $464.9 million (29%) increase in period-to-period earnings before depreciation, depletion and amortization resulted from incremental earnings from our CO_2, Natural Gas Pipelines, Terminals and Kinder Morgan Canada business segments.

Third Quarter 2008 Casualties

Hurricanes

In the third quarter of 2008, Hurricanes Gustav and Ike struck the Gulf Coast communities of southern Texas and Louisiana causing wide-spread damage to residential and commercial property. Fortunately, our primary assets in those areas experienced only relatively minor damage. Plantation Pipe Line Company, which transports refined petroleum products to the southeastern United States and is owned approximately 51% by us, remained fully operational during Hurricane Ike but temporarily moved product at reduced volumes due to limited refinery supply in Louisiana as a result of both Hurricanes Gustav and Ike. Hurricane Ike limited supply flexibility by temporarily reducing Plantation's transportation volumes to approximately 75% of its typical volumes, although full capacity was available. Delivery volumes on Plantation returned to pre-hurricane levels in early October 2008.

In addition, several facilities included within our Southeast terminal operations experienced tight gasoline supplies as a result of reduced refinery output. In general, diesel and jet fuel inventory levels were not significantly impacted, and we continue to replenish inventories as we receive product from the refineries. Our large liquids terminal complex located on the Houston, Texas Ship Channel experienced no significant damage and resumed operations shortly after the passing of Hurricane Ike. Our Texas intrastate natural gas pipeline group also operated during Hurricane Ike but at reduced capacity. The intrastate group's throughput volumes are now back to normal levels. Our Texas petroleum coke terminal operations did not operate for approximately one week following the landing of Hurricane Ike, primarily because the refineries served by the terminals were shut-down. Our partnership in International Marine Terminals, located in Port Sulphur, Louisiana and owned 66 2/3% by us, incurred property damage due to flooding caused by the storms; however, the facility has resumed limited service and further damage assessments are in process.

In the third quarter of 2008, we realized a $4.0 million decrease in total segment earnings before depreciation, depletion and amortization due to incremental expenses associated with these storms (described in the footnotes to

the tables above, but excluding lost business and lost revenues from decreased volumes transported on our pipelines, which is disclosed below in “—Fires”), and we included this decrease in the certain items described in the footnotes to the table above.

Fires

In the third quarter of 2008, we experienced fire damage at three separate terminal locations. The largest was an explosion and fire at our Pasadena, Texas liquids terminal facility on September 23, 2008. The fire primarily damaged a manifold system used for liquids distribution. Our nearby liquids terminal facility located in Galena Park, Texas was not affected by the fire.

We intend to repair the damaged portions of each separate terminal facility. Combined, we recognized a $6.8 million decrease in total segment earnings before depreciation, depletion and amortization due to incremental expenses associated with these three fires (excluding lost business and lost revenues), and we included this decrease in the certain items described in the footnotes to the table above.

We estimate that our total segment earnings before depreciation, depletion and amortization in the third quarter of 2008 was negatively affected by an additional $21.5 million, due to lost business as a result of the hurricanes and fires. Although we continue to evaluate the full effect of these casualties on our operations, we do not believe that they will have a material adverse effect on our business, financial position, results of operations or cash flows.

Products Pipelines

	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
	(In millions, except operating statistics)			
Revenues(a)	$ 205.6	$ 217.0	$ 602.5	$ 642.4
Operating expenses(b)	(78.7)	(84.2)	(209.6)	(234.4)
Other income (expense)(c)	(0.1)	0.6	0.9	2.9
Earnings from equity investments(d)	5.0	8.0	21.2	24.4
Interest income and Other, net-income (expense)(e)	0.4	2.9	2.2	8.2
Income tax benefit (expense)	(1.8)	(6.4)	(8.5)	(14.8)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	$ 130.4	$ 137.9	$ 408.7	$ 428.7
Gasoline (MMBbl)	101.1	111.2	299.5	332.0
Diesel fuel (MMBbl)	40.0	42.1	120.2	122.2
Jet fuel (MMBbl)	29.6	31.9	89.2	94.0
Total refined product volumes (MMBbl)	170.7	185.2	508.9	548.2
Natural gas liquids (MMBbl)	5.8	7.4	18.7	22.8
Total delivery volumes (MMBbl)(f)	176.5	192.6	527.6	571.0

(a) Three and nine month 2008 amounts include a $5.1 million decrease in revenues from the proposed settlement of certain litigation matters related to our Pacific operations’ East Line pipeline.

(b) Three and nine month 2008 amounts include a $4.2 million increase in expense from the proposed settlement of certain litigation matters related to our Pacific operations’ East Line pipeline, and a $0.1 million increase in expense related to hurricane clean-up and repair activities. Nine month 2008 amount includes a $3.0 million decrease in expense related to our Pacific operations and a $3.0 million increase in expense related to our Calnev Pipeline associated with legal liability adjustments. Three and nine month 2007 amounts include a $15.0 million increase in expense for a litigation settlement reached with Contra Costa County, California, and a $3.2 million increase in expense from the settlement of certain litigation matters related to our West Coast refined products terminal operations. Nine month 2007 amount also includes an increase in expense of $2.2 million associated with environmental liability adjustments.

(c) Nine month 2008 amount includes a gain of $1.3 million from the 2007 sale of our North System.

(d) Three and nine month 2008 amounts include an expense of $0.1 million reflecting our portion of Plantation Pipe Line Company's expenses related to hurricane clean-up and repair activities.

(e) Three and nine month 2008 amounts include decreases in income of $0.7 million and $1.4 million, respectively, resulting from unrealized foreign currency losses on long-term debt transactions. Three and nine month 2007 amounts include increases in income of $0.9 and $1.7 million, respectively, resulting from unrealized foreign currency gains on long-term debt transactions.

(f) Includes Pacific, Plantation, Calnev, Central Florida, Cochin and Cypress pipeline volumes.

Combined, the certain items described in the footnotes to the table above increased our Products Pipelines' segment earnings before depreciation, depletion and amortization expenses by $7.1 million and $9.1 million, respectively, when compared to the third quarter and first nine months of last year. The largest of these items includes (i) a combined $18.2 million increase in earnings in both the third quarter and first nine months of 2008 from incremental operating expenses recognized in the third quarter of 2007 and associated with settlements of certain litigation matters related to our Pacific and West Coast terminal operations; and (ii) a combined $9.3 million decrease in earnings in both the third quarter and first nine months of 2008 from decreases in revenues and increases in expenses recognized in the third quarter of 2008 and associated with proposed settlements of certain litigation matters involving shippers on our Pacific operations' East Line pipeline. For more information on our litigation matters, see Note 3 to our consolidated financial statements included elsewhere in this report.

Following is information related to the increases and decreases, in the third quarter and first nine months of 2008 compared to the same periods of 2007, of the segment's remaining changes in (i) earnings before depreciation, depletion and amortization expense (EBDA); and (ii) operating revenues:

Three months ended September 30, 2008 versus Three months ended September 30, 2007

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
North System	$ (11.0)	(100)%	$ (14.4)	(100)%
Pacific operations	(9.2)	(13)%	(2.3)	(2)%
Cochin Pipeline System	(1.0)	(10)%	(3.5)	(21)%
Southeast Terminals	3.9	34%	8.8	55%
West Coast Terminals	2.3	20%	2.7	15%
Central Florida Pipeline	1.1	11%	1.6	14%
All others (including eliminations)	(0.7)	(2)%	0.8	2%
Total Products Pipelines	$ (14.6)	(9)%	$ (6.3)	(3)%

Nine months ended September 30, 2008 versus Nine months ended September 30, 2007

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
North System	$ (28.1)	(100)%	$ (41.1)	(100)%
Pacific operations	(10.6)	(5)%	0.3	—
Cochin Pipeline System	(2.9)	(10)%	(16.0)	(29)%
Southeast Terminals	7.3	23%	10.8	21%
West Coast Terminals	—	—	3.8	7%
Central Florida Pipeline	4.0	14%	4.0	12%
All others (including eliminations)	1.2	1%	3.4	3%
Total Products Pipelines	$ (29.1)	(7)%	$ (34.8)	(5)%

The period-to-period decreases in both segment earnings before depreciation, depletion and amortization expenses and segment revenues attributable to our North System were due to our October 2007 divestiture of the approximately 1,600-mile interstate common carrier liquids pipeline system and our 50% ownership interest in the Heartland Pipeline Company (collectively referred to in this report as our North System) to ONEOK Partners, L.P. Following purchase price adjustments, we received approximately $295.7 million in cash for the sale of our North

System. We accounted for our North System business as a discontinued operation pursuant to generally accepted accounting principles which require that our income statement be formatted to separate the divested business from our continuing operations; however, as discussed above, because the sale of our North System does not change the structure of our internal organization in a manner that causes a change to our reportable business segments, we have included the North System's operating results within our Products Pipelines business segment disclosures presented in this report for all periods presented in this discussion and analysis. This decision was based on the way our management organizes segments internally to make operating decisions and assess performance.

We earned net income from our North System (discontinued operations) of $8.6 million and $21.1 million, respectively, for the three and nine months ended September 30, 2007, and we recognized a $152.8 million gain on disposal of the North System in the fourth quarter of 2007. We also recorded incremental gain adjustments of $1.3 million in the first nine months of 2008. For more information regarding this transaction, see Note 2 to our consolidated financial statements included elsewhere in this report. For information on our reconciliation of segment information with our consolidated general-purpose financial statements, see Note 11 to our consolidated financial statements included elsewhere in this report.

The decreases in earnings before depreciation, depletion and amortization from our Pacific operations were primarily due to increases in system-wide operating and maintenance expenses of $6.8 million (47%) and $14.1 million (32%), respectively, in the comparable three and nine month periods of 2008, relative to last year. The increases primarily reflect higher major maintenance and pipeline integrity expenses (resulting mainly from project timing), lower capitalized overhead credits, and incremental expenses associated with both legal and environmental liability adjustments.

Total revenues earned by our Pacific operations in the third quarter of 2008 decreased $2.3 million (2%) compared to the third quarter last year, mainly due to an 8% decrease in mainline delivery volumes (primarily gasoline volumes) as a result of reduced demand (primarily in the states of California and Arizona). For the comparable nine month periods, our Pacific operations' revenues were essentially flat across both years, as higher pipeline delivery revenues were largely offset by lower fee-based terminal revenues. The year-over-year increase in refined products delivery revenues resulted from both higher average tariff rates in 2008, and a more favorable delivery mix of higher-rate East Line volumes versus lower-rate West Line volumes.

The decreases in earnings before depreciation, depletion and amortization expenses from our Cochin Pipeline were largely revenue related, linked heavily to lower pipeline delivery volumes in 2008 versus 2007. The decreases in volumes were largely due to a continued decrease in demand for propane in Eastern Canadian and Midwestern U.S. petrochemical and fuel markets since the end of the third quarter last year.

When compared to the same quarter last year, we benefitted in the third quarter of 2008 from improved performances from our Southeast and West Coast liquids terminal operations, and from our Central Florida Pipeline. The increases in earnings before depreciation, depletion and amortization expenses from these operations primarily related to higher margins on liquids inventory sales, increased earnings from incremental terminal throughput and storage activity, increased demand for ethanol, and incremental returns from the completion of a number of capital expansion projects that modified and upgraded terminal infrastructure, enabling us to provide additional ethanol related services to our customers. The increase in earnings from our Central Florida Pipeline were also related to higher product delivery revenues, driven by an increase in the average tariff per barrel as a result of a mid-year 2007 tariff rate increase on product deliveries.

For all segment assets combined, revenues for the third quarter of 2008 from refined petroleum products deliveries were flat, but total volumes delivered fell 7.9%, when compared to the third quarter of 2007. Compared to the third quarter last year, the segment's volumes were negatively impacted by reductions in demand, driven primarily by higher crude oil and refined product prices and weaker economic conditions, and partly by lost business associated with two hurricanes in the third quarter of 2008. The decrease in delivery volumes included a 9% drop in gasoline volumes, a 5% drop in diesel fuel volumes, and a 7% decline in total jet fuel volumes. Through nine months, total refined products delivery revenues were up 1.8%, but volumes declined 7.2%, when compared to the first nine months last year. Excluding deliveries by Plantation Pipeline, total segment refined products delivery volumes decreased 7.3% and 5.8%, respectively, in the comparable three and nine month periods. Although Plantation sustained no hurricane damage in 2008, the pipeline system pumped reduced volumes in the third quarter of 2008 due to hurricane-induced refinery shut-downs and to extended delays in restarting certain refineries impacted by the hurricanes. Delivery volumes on Plantation returned to pre-hurricane levels in early October 2008.

Natural Gas Pipelines

	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
	(In millions, except operating statistics)			
Revenues	$ 2,359.4	$ 1,526.8	$ 6,916.6	$ 4,755.3
Operating expenses(a)	(2,203.3)	(1,387.8)	(6,464.0)	(4,348.9)
Other income	—	0.4	2.7	3.1
Earnings from equity investments(b)	25.6	4.0	80.4	14.2
Interest income and Other, net-income (c)	3.9	—	21.8	0.2
Income tax benefit (expense)	(0.6)	(1.4)	(1.8)	(2.6)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	$ 185.0	$ 142.0	$ 555.7	$ 421.3
Natural gas transport volumes (Trillion Btus)(d)	559.0	441.7	1,599.5	1,276.2
Natural gas sales volumes (Trillion Btus)(e)	220.0	224.4	660.0	641.0

(a) Three and nine month 2008 amounts include (i) a $12.2 million increase in income and a $0.9 million decrease in income, respectively, resulting from unrealized mark to market gains and losses due to the discontinuance of hedge accounting at Casper Douglas; and (ii) a $4.4 million increase in expense related to hurricane clean-up and repair activities. Beginning in the second quarter of 2008, our Casper and Douglas gas processing operations discontinued hedge accounting.

(b) Nine month 2007 amount includes an expense of $1.0 million reflecting our portion of a loss from the early extinguishment of debt by Red Cedar Gathering Company.

(c) Nine month 2008 amount includes a $13.0 million gain from the sale of our 25% equity ownership interest in Thunder Creek Gas Services, LLC.

(d) Includes Kinder Morgan Interstate Gas Transmission LLC, Trailblazer Pipeline Company LLC, TransColorado Gas Transmission Company LLC, Rockies Express Pipeline LLC, and Texas intrastate natural gas pipeline group pipeline volumes.

(e) Represents Texas intrastate natural gas pipeline group volumes.

For the three and nine months ended September 30, 2008, the certain items related to our Natural Gas Pipelines business segment described in the footnotes to the table above increased earnings before depreciation, depletion and amortization expenses by $7.8 million and $8.7 million, respectively, when compared to the same periods last year. The largest of these items include (i) an increase in earnings of $12.2 million in the comparable three month periods, and a decrease in earnings of $0.9 million in the comparable nine month periods, from unrealized mark to market gains and losses resulting from the removal of hedge designation, effective April 1, 2008, on certain derivative contracts used to mitigate the price risk associated with future sales of natural gas liquids by our Casper and Douglas natural gas processing operations; and (ii) an increase in earnings of $13.0 million in the comparable nine month periods, representing the gain realized from the sale of our 25% ownership interest in Thunder Creek Gas Services, LLC in the second quarter of 2008. For more information on our discontinuance of hedge accounting, see Note 10 to our consolidated financial statements included elsewhere in this report. For more information on the sale of our investment in Thunder Creek, see Note 2 to our consolidated financial statements included elsewhere in this report.

Following is information related to the increases and decreases, in the third quarter and first nine months of 2008 compared to the same periods of 2007, of the segment's (i) remaining changes in earnings before depreciation, depletion and amortization expense (EBDA); and (ii) changes in operating revenues:

Three months ended September 30, 2008 versus Three months ended September 30, 2007

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Rockies Express Pipeline	$ 23.0	568%	$ —	—
Texas Intrastate Natural Gas Pipeline Group	13.6	18%	834.7	59%
TransColorado Pipeline	3.1	28%	2.9	23%
Kinder Morgan Louisiana Pipeline	3.0	n/a	—	—
Casper and Douglas gas processing	(3.0)	(48)%	3.9	14%
Trailblazer Pipeline	(2.7)	(20)%	(1.1)	(7)%
All others	(1.8)	(5)%	(7.9)	(13)%
Intrasegment Eliminations	—	—	0.1	27%
Total Natural Gas Pipelines	$ 35.2	25%	$ 832.6	55%

Nine months ended September 30, 2008 versus Nine months ended September 30, 2007

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Rockies Express Pipeline	$ 68.3	707%	$ —	—
Texas Intrastate Natural Gas Pipeline Group	50.2	21%	2,118.9	48%
TransColorado Pipeline	9.2	29%	9.7	26%
Kinder Morgan Louisiana Pipeline	6.0	n/a	—	—
Casper and Douglas gas processing	(5.8)	(38)%	40.9	58%
Trailblazer Pipeline	(1.5)	(4)%	(1.5)	(4)%
All others	(0.7)	(1)%	(4.4)	3%
Intrasegment Eliminations	—	—	(2.3)	(224)%
Total Natural Gas Pipelines	$ 125.7	30%	$ 2,161.3	45%

The overall increases in segment earnings before depreciation, depletion and amortization expenses in both the three and nine months ended September 30, 2008, when compared to the same periods last year, were driven primarily by incremental contributions from our 51% equity ownership interest in the Rockies Express Pipeline, higher earnings from our Texas intrastate natural gas pipeline group, improved performance from our TransColorado Pipeline, and incremental earnings from our Kinder Morgan Louisiana Pipeline.

The incremental earnings from our investment in Rockies Express relates to higher net income earned by Rockies Express Pipeline LLC, primarily due to the start-up of service on the Rockies Express-West pipeline segment in January and May 2008. Rockies Express-West began interim service for up to 1.4 billion cubic feet per day of natural gas on the segment's first 503 miles of pipe on January 12, 2008, and service on the remaining 210 miles (to Audrain County, Missouri) began on May 20, 2008. Now fully operational, Rockies Express-West has the capacity to transport up to 1.5 billion cubic feet per day and can make deliveries to interconnects with our KMIGT pipeline system, Northern Natural Gas Company, Natural Gas Pipeline Company of America LLC, ANR and Panhandle Eastern Pipeline Company.

Rockies Express conducted further hydrostatic testing of portions of its pipeline system during September 2008 to satisfy U.S. Department of Transportation testing requirements to operate at its targeted higher operating pressure. This hydrostatic test resulted in a temporary outage of pipeline delivery points and an overall reduction of firm capacity available to firm shippers. By the terms of the Rockies Express FERC Gas Tariff, firm shippers are entitled to daily reservation revenue credits for non-force majeure and planned maintenance outages, and the estimated impact from any temporary outages were included in our third quarter results.

Our Texas intrastate natural gas pipeline group includes the operations of our (i) Kinder Morgan Tejas Pipeline (including Kinder Morgan Border Pipeline); (ii) Kinder Morgan Texas Pipeline; (iii) Kinder Morgan North

Texas Pipeline; and (iv) Mier-Monterrey Mexico Pipeline. Combined, the group's quarter-to-quarter increase in earnings in 2008 versus 2007 was mainly attributable to higher natural gas sales margins and greater natural gas processing volumes and margins. For the comparable nine month periods, the group also benefitted, in 2008, from incremental natural gas transport and fee-based storage revenues due to a long-term contract with one of its largest customers that became effective April 1, 2007.

The higher natural gas sales margins in both the third quarter and first nine months of 2008 were mainly driven by higher average sales prices, when compared to the same prior year periods. Primarily due to the temporary impact of Hurricane Ike, the Texas intrastate group’s natural gas transportation and sales volumes were down 9% and 2%, respectively, in the third quarter of 2008 compared to the third quarter last year; however, due to the start-up of Rockies Express-West, total segment transport volumes increased nearly 27%.

Because our intrastate group buys and sells significant quantities of natural gas, the variances from period to period in both segment revenues and segment operating expenses (which include natural gas costs of sales) are partly due to changes in our intrastate group’s average prices and volumes for natural gas purchased and sold. To the extent possible, we balance the pricing and timing of our natural gas purchases to our natural gas sales, and these contracts are frequently settled in terms of an index price for both purchases and sales. In order to minimize commodity price risk, we attempt to balance sales with purchases at the index price on the date of settlement.

The increases in earnings from our TransColorado Pipeline reflect contract improvements and expansions completed since the end of the third quarter of 2007, caused by an increase in natural gas production in the Piceance and San Juan basins of New Mexico and Colorado. Also, in December 2007, we completed the approximately $50 million Blanco-Meeker expansion project on our TransColorado Pipeline. The project was placed into service on January 1, 2008, and it boosted natural gas transportation capacity on the pipeline by approximately 250 million cubic feet per day from the Blanco Hub area in San Juan County, New Mexico through TransColorado’s existing pipeline for deliveries to the Rockies Express Pipeline at an existing point of interconnection located at the Meeker Hub in Rio Blanco County, Colorado. All of the incremental capacity is subscribed under a long-term contract with ConocoPhillips.

The incremental earnings before depreciation, depletion and amortization expenses from our Kinder Morgan Louisiana Pipeline reflects other non-operating income realized in the third quarter and first nine months of 2008 pursuant to FERC regulations governing allowances for capital funds that are used for pipeline construction costs (an equity cost of capital allowance). The equity cost of capital allowance provides for a reasonable return on construction costs that are funded by equity contributions, similar to the allowance for capital costs funded by borrowings.

The decreases in period-to-period earnings before depreciation, depletion and amortization from our Casper Douglas gas processing operations were primarily attributable to higher natural gas purchase costs, due to increases in both prices and volumes, relative to last year. The higher cost of sales expense more than offset period-to-period revenue increases resulting from both higher average prices on natural gas liquids sales and higher revenues from sales of excess natural gas.

The decreases in earnings before depreciation, depletion and amortization from our Trailblazer Pipeline were mainly due to lower revenues from natural gas transportation services in the third quarter of 2008, and to unfavorable timing differences on the settlement of pipeline transportation imbalances in both the three and nine month periods of 2008, relative to 2007.

CO_2

	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
	(In millions, except operating statistics)			
Revenues	$ 305.2	$ 210.6	$ 900.2	$ 601.7
Operating expenses	(105.4)	(75.8)	(292.7)	(222.6)
Earnings from equity investments	4.2	4.1	15.3	14.3
Other, net-income (expense)	—	—	(0.2)	—
Income tax benefit (expense)	(0.7)	(0.9)	(2.9)	(1.1)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	$ 203.3	$ 138.0	$ 619.7	$ 392.3
Carbon dioxide delivery volumes (Bcf)(a)	171.3	150.4	530.1	472.6
SACROC oil production (gross)(MBbl/d)(b)	27.9	27.3	27.6	28.4
SACROC oil production (net)(MBbl/d)(c)	23.3	22.8	23.0	23.6
Yates oil production (gross)(MBbl/d)(b)	27.1	27.1	27.9	26.7
Yates oil production (net)(MBbl/d)(c)	12.0	12.0	12.4	11.9
Natural gas liquids sales volumes (net)(MBbl/d)(c)	7.6	10.0	8.7	9.8
Realized weighted average oil price per Bbl(d)(e)	$ 51.45	$ 36.77	$ 51.50	$ 35.56
Realized weighted average natural gas liquids price per Bbl(e)(f)	$ 77.97	$ 53.68	$ 73.37	$ 48.66

(a) Includes Cortez, Central Basin, Canyon Reef Carriers, Centerline and Pecos pipeline volumes.

(b) Represents 100% of the production from the field. We own an approximately 97% working interest in the SACROC unit and an approximately 50% working interest in the Yates unit.

(c) Net to Kinder Morgan, after royalties and outside working interests.

(d) Includes all Kinder Morgan crude oil production properties.

(e) Hedge gains/losses for crude oil and natural gas liquids are included with crude oil.

(f) Includes production attributable to leasehold ownership and production attributable to our ownership in processing plants and third party processing agreements.

Our CO_2 segment consists of Kinder Morgan CO_2 Company, L.P. and its consolidated affiliates. The segment's primary businesses involve the production, marketing and transportation of both carbon dioxide (commonly called CO_2) and crude oil, and the production and marketing of natural gas and natural gas liquids. For each of the segment's two primary businesses, following is information related to the increases and decreases, in the comparable three and nine month periods of 2008 and 2007, of the segment's earnings before depreciation, depletion and amortization (EBDA), and operating revenues:

<u>Three months ended September 30, 2008 versus Three months ended September 30, 2007</u>

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Sales and Transportation Activities	$ 39.6	94%	$ 47.8	105%
Oil and Gas Producing Activities	25.7	27%	56.9	32%
Intrasegment Eliminations	—	—	(10.1)	(88)%
Total CO_2	$ 65.3	47%	$ 94.6	45%

Nine months ended September 30, 2008 versus Nine months ended September 30, 2007

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Sales and Transportation Activities	$ 96.7	77%	$ 113.2	86%
Oil and Gas Producing Activities	130.7	49%	211.2	42%
Intrasegment Eliminations	—	—	(25.9)	(77)%
Total CO_2	$ 227.4	58%	$ 298.5	50%

The overall period-to-period increases in segment earnings before depreciation, depletion and amortization expenses resulted from higher earnings from both oil and gas producing activities and carbon dioxide sales and transportation activities. A quarter-over-quarter increase in carbon dioxide sales and transportation revenues was the main cause for the increase in segment earnings in the third quarter of 2008, when compared to the same period of 2007, and for the full nine month periods, the segment's increase in earnings in 2008 was driven by increased carbon dioxide, crude oil, and natural gas liquids sales revenues, largely due to increases in average crude oil (which also impacts the price of carbon dioxide) and natural gas plant product prices since the third quarter of 2007.

Generally, earnings for the segment's oil and gas producing activities, which include the operations associated with its ownership interests in oil-producing fields and natural gas processing plants, are closely aligned with our realized price levels for crude oil and natural gas liquids products. Revenues from crude oil sales and natural gas plant products sales increased $50.2 million (42%) and $5.0 million (10%), respectively, in the third quarter of 2008 compared to the third quarter of 2007, and increased $157.0 million (45%) and $44.4 million (34%), respectively, in the first nine months of 2008 compared to the first nine months of 2007.

With respect to crude oil, overall sales volumes were essentially flat across both three and nine month comparable periods, but we benefitted from increases of 40% and 45%, respectively, in our realized weighted average price per barrel. With respect to natural gas liquids, for the three and nine month periods, decreases in sales volumes of 24% and 11%, respectively, were more than offset by increases of 45% and 51%, respectively, in our realized weighted average price per barrel. The quarterly decrease in liquids sales volumes was largely related to the effects from Hurricane Ike, which temporarily shut-down third-party fractionation facilities. Volumes were also negatively affected, in the comparable nine month periods, by operational issues on a third party owned pipeline, which resulted in pro-rationing (production allocation).

Because prices of crude oil and natural gas liquids are subject to external factors over which we have no control, and because future price changes may be volatile, our CO_2 segment is exposed to commodity price risk related to the price volatility of crude oil and natural gas liquids. To some extent, we are able to mitigate this risk through a long-term hedging strategy that is intended to generate more stable realized prices by using derivative contracts as hedges to the exposure of fluctuating expected future cash flows produced by changes in commodity sales prices. Nonetheless, decreases in the prices of crude oil and natural gas liquids will have a negative impact on the results of our CO_2 business segment. All of our hedge gains and losses for crude oil and natural gas liquids are included in our realized average price for oil. Had we not used energy derivative contracts to transfer commodity price risk, our crude oil sales prices would have averaged $116.08 per barrel in the third quarter of 2008, and $73.12 per barrel in the third quarter of 2007. For more information on our hedging activities, see Note 10 to our consolidated financial statements included elsewhere in this report.

Average gross oil production for the third quarter of 2008 was 27.9 thousand barrels per day at the SACROC field unit, 2% higher when compared to the third quarter of 2007. At the Yates unit, average gross oil production in the third quarter of 2008 was identical to the production in the same quarter last year, but for the nine month period of 2008, Yates' gross oil production averaged 27.9 thousand barrels per day, up 1.2 thousand barrels per day over the same prior year period and offsetting a 0.8 thousand barrel per day decrease in production at SACROC.

The period-to-period increases in earnings before depreciation, depletion and amortization from the segment's sales and transportation activities were largely revenue related, reflecting both higher carbon dioxide sales revenues and higher carbon dioxide and crude oil pipeline transportation revenues. The increases from carbon dioxide sales revenues were related to increases in both price and volume. The increases from higher pipeline transportation revenues were due to higher volumes.

Overall, our CO_2 segment reported increases of $32.3 million (214%) and $66.3 million (153%), respectively, in carbon dioxide sales revenues in the third quarter and first nine months of 2008, relative to the same periods a year earlier. The increases in sales revenues were primarily driven by increases of 104% and 90%, respectively, in average sales prices in 2008, and partially driven by increases in sales volumes of 27% and 16%, respectively. Similarly, total pipeline transportation revenues increased $4.2 million (23%) and $15.4 million (30%), respectively, in the comparable three and nine month periods, chiefly due to increases in carbon dioxide delivery volumes of 14% and 12%, respectively.

The increases in average sales prices reflect continued customer demand for carbon dioxide for use in oil recovery projects throughout the Permian Basin area and, in addition, a portion of our carbon dioxide contracts are tied to crude oil prices, which as discussed above, have increased since the third quarter of 2007. We do not recognize profits on carbon dioxide sales to ourselves. The increases in sales and delivery volumes were largely due to the January 17, 2008 start-up of the Doe Canyon carbon dioxide source field located in Dolores County, Colorado. The new carbon dioxide source field is named the Doe Canyon Deep unit, and we hold an approximately 87% working interest in the field. Since January 2007, we have invested approximately $90 million to develop this source field. In addition, investments were also made to drill additional carbon dioxide wells at the McElmo Dome unit, increase transportation capacity on the Cortez Pipeline, and extend the Cortez Pipeline to the new Doe Canyon Deep unit.

Compared to the third quarter and first nine months of 2007, the segment's $29.6 million (39%) and $70.1 million (31%) increases in combined operating expenses in the three and nine months ended September 30, 2008, respectively, were largely due to higher severance and property tax expenses, field operating expenses, and fuel and power expenses. The increases in severance tax expenses were related to the period-to-period increases in crude oil revenues. The increases in property tax expenses were largely due to higher oil prices leading to higher tax assessments, and increased asset infrastructure resulting from the capital investments we have made since the end of the third quarter of 2007. The increases in operating expenses were driven by both higher well workover and repair expenses in 2008 and rising price levels since the end of the third quarter of 2007, which impacted rig costs and other materials and services. The increases in workover expenses were largely related to infrastructure expansion projects at the SACROC and Yates oil field units and at the McElmo Dome carbon dioxide unit. The increases in operating expenses from price level changes were largely due to increased demand driving up prices charged by the industry's material and service providers.

Terminals

	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
	(In millions, except operating statistics)			
Revenues	$ 306.2	$ 247.2	$ 887.1	$ 691.3
Operating expenses(a)	(175.1)	(158.0)	(483.9)	(390.9)
Other income (expense)(b)	(4.0)	1.5	(3.6)	5.9
Earnings from equity investments	0.7	0.3	2.4	0.3
Other, net-income (expense)	(1.3)	0.3	1.4	0.3
Income tax expense(c)	(6.4)	(6.9)	(17.1)	(11.9)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	$ 120.1	$ 84.4	$ 386.3	$ 295.0
Bulk transload tonnage (MMtons)(d)	26.8	24.5	76.5	72.7
Liquids leaseable capacity (MMBbl)	54.2	46.3	54.2	46.3
Liquids utilization %	98.2%	96.5%	98.2%	96.5%

(a) Three and nine month 2008 amounts include $3.6 million increase in expense related to hurricane clean-up and repair activities, a $1.5 million increase in expense related to fire damage and repair activities, and a combined $1.5 million increase in expense from the settlement of certain litigation matters related to our Elizabeth River bulk terminal and our Staten Island liquids terminal. Three and nine month 2007 amounts include a $25.0 million increase in expense from the settlement of certain litigation matters related to our Cora coal terminal.

(b) Three and nine month 2008 amounts include losses of $5.3 million from asset write-offs related to fire damage, and losses of $0.8 million from asset write-offs related to hurricane damage. Nine month 2007 amount includes an increase in income of $1.8 million from property casualty gains associated with the 2005 hurricane season.

(c) Three and nine month 2008 amounts include a decrease in expense of $0.4 million related to hurricane clean-up and repair activities.

(d) Volumes for acquired terminals are included for all periods.

Our Terminals business segment includes the operations of our petroleum, chemical and other liquids terminal facilities (other than those included in our Products Pipelines segment), and all of our coal, petroleum coke, fertilizer, steel, ores and other dry-bulk material services facilities. The net effect of the certain items described in the footnotes to the table above increased earnings before depreciation, depletion and amortization by $12.7 million in the third quarter of 2008 and by $10.9 million in the first nine months of 2008, when compared to the same periods of 2007. The segment's remaining $23.0 million (21%) increase in earnings before depreciation, depletion and amortization in the third quarter of 2008 versus the third quarter of 2007, and its remaining $80.4 million (25%) increase in earnings in the first nine months of 2008 versus the first nine months of 2007 were due to a combination of internal asset expansions and strategic business acquisitions.

Beginning with our acquisition of the Vancouver Wharves bulk marine terminal on May 30, 2007 and including, among others, the terminal assets and operations we acquired from Marine Terminals, Inc. effective September 1, 2007, we have invested approximately $175.3 million in cash to acquire both terminal assets and equity interests in terminal operations, and combined, these acquired operations accounted for incremental amounts of earnings before depreciation, depletion and amortization of $5.6 million, revenues of $19.1 million, and operating expenses of $13.5 million in the third quarter of 2008, and incremental earnings before depreciation, depletion and amortization of $30.5 million, revenues of $84.6 million, equity earnings of $1.7 million, and operating expenses of $55.8 million in the first nine months of 2008.

All of the incremental amounts listed above represent the earnings, revenues and expenses from acquired terminals' operations during the additional months of ownership in 2008, and do not include increases or decreases during the same months we owned the assets in 2007. For more information on our acquisitions, see Note 2 to our consolidated financial statements included elsewhere in this report.

For the terminals owned during identical periods in both 2008 and 2007, earnings before depreciation, depletion and amortization expenses increased $17.4 million (17%) in the third quarter of 2008, and $49.9 million (17%) in the first nine months of 2008, when compared to the same prior year periods. The overall increases in earnings from terminals owned during identical periods in both years represent net changes in terminal results at various locations, and include incremental earnings before depreciation, depletion and amortization in the third quarter and first nine months of 2008 of:

- $5.9 million (22%) and $19.9 million (25%), respectively, from our Gulf Coast terminal facilities, primarily our two large liquids terminal facilities located along the Houston Ship Channel in Pasadena and Galena Park, Texas, primarily due to higher liquids throughput volumes and increased liquids storage capacity as a result of expansions completed since the third quarter of 2007;

- $5.7 million (59%) and $14.4 million (51%), respectively, from our Mid-Atlantic terminals, primarily our Pier IX bulk terminal located in Newport News, Virginia, due to higher period-over-period coal transfer volumes, and our Fairless Hills, Pennsylvania bulk terminal, largely due to incremental earnings from a new import fertilizer facility that began operations in the second quarter of 2008. The increases in coal throughput at Pier IX were largely due to an almost $70 million capital improvement project, completed in the first quarter of 2008, that involved the construction of a new ship dock and the installation of additional terminal equipment. The import fertilizer facility at Fairless Hills cost approximately $11.2 million to build, and included the construction of two storage domes, conveying equipment, and outbound loading facilities for both rail and truck;

- $5.2 million (70%) and $8.0 million (60%), respectively, from our West region terminals, primarily from our Kinder Morgan North 40 terminal, which began operations in the second quarter of 2008, and from our Vancouver Wharves bulk marine terminal, which we acquired on May 30, 2007. The increases were mainly due to higher terminal revenues from liquids throughput and handling services; and

- $3.2 million (23%) and $6.2 million (13%), respectively, from our Northeast terminals, primarily from our Perth Amboy, New Jersey liquids terminal, located in the New York Harbor area, driven by higher liquids throughput volumes as a result of an expansion completed at the end of the first quarter of 2008.

The overall quarter-to-quarter increase in segment earnings before depreciation, depletion and amortization in 2008 versus 2007 from terminals owned during both periods included a decrease of $2.6 million (18%) from our Texas Petcoke terminals, primarily due to lost petroleum coke business, a portion of which was sidelined because of refinery shut-downs following Hurricane Ike. Through nine months, our Texas Petcoke terminals reported an increase in earnings of $2.0 million (5%), when compared to the first nine months of 2007.

For the Terminals segment combined, expansion projects completed since the end of the third quarter of 2007 have increased our liquids terminals' leaseable capacity to 54.2 million barrels, up 17% from a capacity of 46.3 million barrels at the end of the third quarter of 2007. At the same time, we increased our overall liquids utilization capacity rate (the ratio of our actual leased capacity to our estimated potential capacity) to 98.2%, up almost 2% since the third quarter last year.

Kinder Morgan Canada

	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
	(In millions, except operating statistics)			
Revenues	$ 56.6	$ 43.7	$ 143.1	$ 119.8
Operating expenses	(18.6)	(19.3)	(51.3)	(47.2)
Other income (expense)(a)	—	—	—	(377.1)
Earnings from equity investments	(0.9)	—	(0.8)	—
Interest income and Other, net-income (expense)	3.5	2.9	9.6	4.0
Income tax benefit (expense)	(1.0)	(5.2)	2.6	(6.0)
Earnings (loss) before depreciation, depletion and amortization expense and amortization of excess cost of equity investments(b)	$ 39.6	$ 22.1	$ 103.2	$ (306.5)
Transport volumes (MMBbl)	22.6	25.3	63.5	70.1

(a) Nine month 2007 amount represents a goodwill impairment expense recorded by Knight in the first quarter of 2007.

(b) Nine month 2007 amount includes losses of $349.2 million for periods prior to our acquisition date of April 30, 2007.

Our Kinder Morgan Canada business segment includes the operations of the Trans Mountain, Express, and Jet Fuel pipeline systems. We acquired the net assets of the Trans Mountain pipeline system from Knight effective April 30, 2007, and we acquired both a 33 1/3% interest in the Express pipeline system net assets and the net assets of the Jet Fuel pipeline system from Knight effective August 28, 2008. For more information on these acquisitions, see Note 2 to our consolidated financial statements included elsewhere in this report.

According to the provisions of generally accepted accounting principles that prescribe the standards used to account for business combinations, because our acquisition of the Trans Mountain, Express, and Jet Fuel pipeline systems from Knight represented a transfer of assets between entities under common control, we initially recorded the assets and liabilities transferred to us from Knight at their carrying amounts in the accounts of Knight. Furthermore, based on these standards and on our management's consideration of all of the quantitative and qualitative aspects of these two separate transfers of assets between entities under common control, our accompanying financial statements included in this report, and the information in the table above, reflect the results of operations for the first nine months of 2007 as though (i) the transfer of the Trans Mountain pipeline system net assets from Knight had occurred at the date when both Trans Mountain and we met the accounting requirements for entities under common control (January 1, 2006); and (ii) the transfer of both the 33 1/3% interest in the Express pipeline system net assets and the Jet Fuel pipeline system net assets from Knight had occurred at the transfer date of August 28, 2008.

After taking into effect the items described in footnote (b) to the table above, the remaining increases in earnings before depreciation, depletion and amortization for the three and nine months ended September 30, 2008 totaled $17.5 million (79%) and $60.5 million (142%), respectively, when compared to the same prior year periods. The quarter-to-quarter increase consisted of (i) higher earnings of $17.2 million (78%) from our Trans Mountain pipeline operations; and (ii) incremental earnings of $0.3 million from the Express and Jet Fuel pipeline operations. For the comparable nine month periods, the increase in earnings consisted of (i) higher earnings of $20.0 million (47%) from the Trans Mountain pipeline assets we owned in the same periods in both years (May through September); and (ii) incremental earnings of $40.5 million from periods we owned assets in 2008 only.

The increases in earnings from assets owned during the same periods in both years were driven primarily by higher operating revenues, largely due to the April 2007 completion of an expansion project that included the commissioning of ten new pump stations that boosted capacity on Trans Mountain from 225,000 to approximately 260,000 barrels per day, and to the April 28, 2008 completion of the first portion of the Anchor Loop expansion project that boosted pipeline capacity from 260,000 to 285,000 barrels per day and resulted in higher period-to-period average toll rates. We completed construction on a final 15,000 barrel per day expansion on October 30, 2008, and total pipeline capacity is now approximately 300,000 barrels per day. The higher tariffs more than offset declines in mainline throughput volumes of 11% and 9%, respectively, for the comparable three and nine month periods. The decreases in volumes were primarily due to lower demand for water-borne exports out of Vancouver, British Columbia.

Other

	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Earnings increase/(decrease)	
	(In millions-income (expense), except percentages)			
General and administrative expenses(a)	$ (73.1)	$ (63.0)	$ (10.1)	(16%)
Total general and administrative expenses	$ (73.1)	$ (63.0)	$ (10.1)	(16%)
Unallocable interest expense, net of interest income(b)	$ (100.5)	$ (103.5)	$ 3.0	3%
Unallocable income tax expense	(3.7)	—	(3.7)	n/a
Minority interest(c)	(3.1)	(2.4)	(0.7)	(29%)
Total interest and other non-operating expenses	$ (107.3)	$ (105.9)	$ (1.4)	(1%)

	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007	Earnings increase/(decrease)	
	(In millions-income (expense), except percentages)			
General and administrative expenses(d)	$ (222.7)	$ (222.7)	—	—
Total general and administrative expenses	$ (222.7)	$ (222.7)	—	—
Unallocable interest expense, net of interest income(e)	$ (298.1)	$ (293.6)	$ (4.5)	(2%)
Unallocable income tax expense	(8.1)	—	(8.1)	n/a
Minority interest(f)	(11.2)	(4.4)	(6.8)	(155%)
Total interest and other non-operating expenses	$ (317.4)	$ (298.0)	$ (19.4)	(7%)

(a) 2008 amount includes (i) a $1.4 million increase in non-cash compensation expense, allocated to us from Knight (we do not have any obligation, nor do we expect to pay any amounts related to this expense); (ii) a $0.1 million increase in expense related to hurricane clean-up and repair activities; and (iii) a $1.5 million decrease in expense due to the adjustment of certain insurance related liabilities. 2007 amount includes (i) a $1.5 million increase in non-cash compensation expense, allocated to us from Knight (we do not have any obligation, nor do we expect to pay any amounts related to this expense); (ii) a $0.8 million increase in expense related to the cancellation of certain commercial insurance policies; and (iii) a $0.4 million increase in expense for certain Trans Mountain acquisition costs.

(b) 2008 and 2007 amounts each include increases in imputed interest expense of $0.5 million related to our January 1, 2007 Cochin Pipeline acquisition. 2008 amount also includes a $0.2 million increase in interest expense related to the proposed settlement of certain litigation matters related to our Pacific operations' East Line pipeline.

(c) 2008 and 2007 amounts include decreases in expense of $0.2 million and $0.4 million, respectively, related to the minority interest effect from all of the three month 2008 and 2007 items previously disclosed in the footnotes to the tables included in "—Results of Operations."

(d) 2008 amount includes (i) a $4.2 million increase in non-cash compensation expense, allocated to us from Knight (we do not have any obligation, nor do we expect to pay any amounts related to this expense); (ii) a $0.1 million increase in expense related to hurricane clean-up and repair activities; and (iii) a $1.5 million decrease in expense due to the adjustment of certain insurance related liabilities. 2007 amount includes (i) a $24.9 million increase in non-cash compensation expense, allocated to us from Knight (we do not have any obligation, nor do we expect to pay any amounts related to this expense); (ii) a $5.5 million increase in expense from the inclusion of Trans Mountain for periods prior to our acquisition date of April 30, 2007; (iii) a $1.7 million increase in insurance expense associated with the 2005 hurricane season; (iv) a $1.5 million increase in expense for certain Trans Mountain acquisition costs; and (v) a $0.8 million increase in expense related to the cancellation of certain commercial insurance policies.

(e) 2008 and 2007 amounts include increases in imputed interest expense of $1.5 million and $1.7 million, respectively, related to our January 1, 2007 Cochin Pipeline acquisition. 2008 amount also includes a $0.2 million increase in interest expense related to the proposed settlement of certain litigation matters related to our Pacific operations' East Line pipeline. 2007 amount also includes a $1.2 million increase in interest expense from the inclusion of Trans Mountain for periods prior to our acquisition date of April 30, 2007.

(f) 2008 and 2007 amounts include decreases in expense of $0.2 million and $3.9 million, respectively, related to the minority interest effect from all of the nine month 2008 and 2007 items previously disclosed in the footnotes to the tables included in "—Results of Operations."

Items not attributable to any segment include general and administrative expenses, unallocable interest income, unallocable income tax expense, interest expense, and minority interest. Our general and administrative expenses include such items as salaries and employee-related expenses, payroll taxes, insurance, office supplies and rentals, unallocated litigation and environmental expenses, and shared corporate services—including accounting, information technology, human resources and legal services.

Overall, our total general and administrative expenses increased $10.1 million (16%) in the third quarter of 2008, and the certain items described in footnote (a) to the tables above accounted for a decrease in expense of $2.7 million. For the comparable nine month periods, overall general and administrative expenses remained flat; however, the certain items described in footnote (d) to the tables above resulted in a combined $31.6 million decrease in overall expense in 2008, when compared to the first nine months of last year.

The remaining $12.8 million (21%) and $31.6 million (17%) increases in general and administrative expense, for the comparable three and nine month periods respectively, were primarily driven by increased costs of supporting continued customer and business growth, including (i) higher compensation-related expenses—comprising salary and benefit expenses, payroll taxes and other employee and contractor related expenses; and (ii) incremental expenses associated with the assets and businesses we acquired since the third quarter of 2007—including our Express and Jet Fuel pipeline systems acquired from Knight effective August 28, 2008, and our recently acquired bulk terminal operations described above in "—Terminals." We continue to manage our infrastructure expenses in order to allow for further investment in growth segments of our business portfolio.

The $31.6 million decrease in general and administrative expenses disclosed in the footnotes to the table above in the comparable nine month periods from certain items was largely due to the $21.2 million second quarter 2007 non-cash compensation expense allocated to us from Knight and associated with the activities required to complete the May 2007 going-private transaction of KMI (now Knight), largely associated with the acceleration of cashouts of grants of both KMI restricted stock and options to purchase KMI stock. In addition, beginning in the first quarter of 2007, for accounting purposes, Knight has been required to allocate to us, on a monthly basis, certain ongoing compensation expense related to the transaction and we have been required to recognize the amounts as expense on our income statements. However, we are not responsible for paying either the one-time or the ongoing expenses, and accordingly, we recognize the unpaid amounts as contributions to equity—primarily as increases in "Partners' Capital" on our consolidated balance sheets.

Interest expense, net of unallocable interest income, decreased $3.0 million (3%) and increased $4.5 million (2%), respectively, in the third quarter and first nine months of 2008, when compared to the same periods last year. For the comparable three month periods, the overall decrease included a $0.2 million increase in expense due to the certain items described in footnote (b) to the tables above. The remaining $3.2 million (3%) decrease in expense was driven by an 18% decrease in the weighted average interest rate on all of our borrowings, partially offset by a20% increase in average borrowings. For the comparable nine month periods, the overall $4.5 million increase in net interest expense in 2008 versus 2007 included a $1.2 million decrease in expense due to the certain items described in footnote (e) to the tables above. The remaining $5.7 million (2%) increase in expense was driven by a20% increase in average borrowings, partially offset by a 15% drop in our weighted average interest rates.

The period-to-period increase in our average borrowings was largely due to the capital spending (for asset expansion and improvement projects, including additional pipeline construction costs) and the external business acquisitions we have made since September 2007. The decreases in our average borrowing rates reflect a general decrease in variable interest rates since the third quarter last year. As of September 30, 2008, approximately 47% of our $8,340.9 million consolidated debt balance (excluding the value of interest rate swap agreements) was subject to variable interest rates—either as short-term or long-term variable rate debt obligations or as fixed-rate debt converted to variable rates through the use of interest rate swaps. As of September 30, 2007, approximately 42% of

our $7,053.8 million consolidated debt balance (excluding the value of interest rate swap agreements) was subject to variable interest rates.

The incremental unallocable income tax expense, in both the third quarter and first nine months of 2008, relates to higher corporate income tax accruals for the Texas margin tax, an entity-level tax initiated January 1, 2007 and imposed on the amount of our total revenue that is apportioned to the state of Texas. The decreases in earnings from incremental minority interest expense relates to higher overall partnership income in 2008 versus 2007.

Financial Condition

Capital Structure

We attempt to maintain a relatively conservative overall capital structure, with a long-term target mix of approximately 50% equity and 50% debt. In addition to our results of operations, our debt and capital balances are affected by our financing activities, as discussed below in "—Financing Activities."

The following table illustrates the sources of our invested capital (dollars in millions):

	September 30, 2008	December 31, 2007
Long-term debt, excluding value of interest rate swaps	$ 8,056.2	$ 6,455.9
Minority interest	57.9	54.2
Partners' capital, excluding accumulated other comprehensive loss	6,284.5	5,712.3
Total capitalization	14,398.6	12,222.4
Short-term debt, less cash and cash equivalents	231.9	551.3
Total invested capital	$ 14,630.5	$ 12,773.7
Capitalization:		
Long-term debt, excluding value of interest rate swaps	56.0%	52.8%
Minority interest	0.4%	0.5%
Partners' capital, excluding accumulated other comprehensive loss	43.6%	46.7%
	100.0%	100.0%
Invested Capital:		
Total debt, less cash and cash equivalents and excluding value of interest rate swaps	56.6%	54.9%
Partners' capital and minority interest, excluding accumulated other comprehensive loss	43.4%	45.1%
	100.0%	100.0%

Our primary cash requirements, in addition to normal operating expenses, are debt service, sustaining capital expenditures, expansion capital expenditures and quarterly distributions to our common unitholders, Class B unitholder and general partner. In addition to utilizing cash generated from operations, we could meet our cash requirements for expansion capital expenditures through borrowings under our credit facility, issuing short-term commercial paper, long-term notes or additional common units or the proceeds from purchases of additional i-units by KMR with the proceeds from issuances of additional KMR shares. Further information on our financing strategies and activities can be found in our 2007 Form 10-K.

As part of our financial strategy, we try to maintain an investment-grade credit rating, which involves, among other things, the issuance of additional limited partner units in connection with our acquisitions and internal growth activities in order to maintain acceptable financial ratios.

On May 30, 2006, Standard & Poor's Rating Services and Moody's Investors Service each placed our long-term credit ratings on credit watch pending the resolution of KMI's going-private transaction. On January 5, 2007, in anticipation of the going-private transaction closing, S&P downgraded us one level to BBB and removed our rating from credit watch with negative implications. As previously noted by Moody's in its credit opinion dated November 15, 2006, it downgraded our credit rating from Baa1 to Baa2 on May 30, 2007, following the closing of the going-private transaction. Additionally, our rating was downgraded by Fitch Ratings from BBB+ to BBB on April 11, 2007. Currently, our long-term corporate debt credit rating is BBB, Baa2 and BBB, respectively, at S&P, Moody's and Fitch.

On October 13, 2008, S&P revised its outlook on our long-term credit rating to negative from stable (but affirmed our long-term credit rating at BBB), due to our previously announced expected delay and cost increases associated with the completion of the Rockies Express Pipeline project. At the same time, S&P lowered our short-term credit rating to A-3 from A-2.

Short-term Liquidity

Our principal sources of short-term liquidity are (i) our $1.85 billion five-year senior unsecured revolving credit facility that matures August 18, 2010; (ii) our $1.85 billion short-term commercial paper program (which is supported by our bank credit facility, with the amount available for borrowing under our credit facility being reduced by our outstanding commercial paper borrowings); and (iii) cash from operations (discussed following).

Borrowings under our five-year credit facility can be used for general partnership purposes and as a backup for our commercial paper program. The facility can be amended to allow for borrowings up to $2.1 billion. As of September 30, 2008, the outstanding balance under our five-year credit facility was $295.0 million, and there were no borrowings under our commercial paper program. As of December 31, 2007, there were no borrowings under our credit facility, and we had $589.1 million of commercial paper outstanding. As of September 30, 2008, our outstanding short-term debt was $284.7 million, primarily consisting of a $250 million principal amount of 6.3% senior notes that matures on February 1, 2009.

We provide for additional liquidity by maintaining a sizable amount of excess borrowing capacity related to our commercial paper program and long-term revolving credit facility. As a result of the revision to our short-term credit rating and the current commercial paper market conditions, we are unable to access commercial paper borrowings; however, we expect that our financing and liquidity needs will continue to be met through borrowings made under our long-term bank credit facility. After reduction for our letters of credit and commercial paper outstanding (none at September 30, 2008), the remaining available borrowing capacity under our bank credit facility was $1,168.5 million as of September 30, 2008. Currently, we believe our liquidity to be adequate.

Some of our customers are experiencing, or may experience in the future, severe financial problems that have had or may have a significant impact on their creditworthiness. These financial problems may arise from the current financial crises, changes in commodity prices or otherwise. We are working to implement, to the extent allowable under applicable contracts, tariffs and regulations, prepayments and other security requirements, such as letters of credit, to enhance our credit position relating to amounts owed from these customers. We cannot provide assurance that one or more of our (current or future) financially distressed customers will not default on their obligations to us or that such a default or defaults will not have a material adverse effect on our business, financial position, future results of operations, or future cash flows; however, we believe we have provided adequate allowance for such customers.

On September 15, 2008, Lehman Brothers Holdings Inc. filed for bankruptcy protection under the provisions of Chapter 11 of the U.S. Bankruptcy Code. No Lehman Brothers affiliate is an administrative agent for us or any of our subsidiaries; however, one of the Lehman entities is a lending bank providing less than 5% of the commitments in our $1.85 billion five-year credit facility. It also provides less than 5% of the commitments in Rockies Express' $2.0 billion credit facility (we are a 51% owner in Rockies Express) and less than 10% of the commitments in Midcontinent Express' $1.4 billion credit facility (we are a 50% owner in Midcontinent Express). Since Lehman Brothers declared bankruptcy, its affiliate which is a party to our, the Rockies Express and the Midcontinent Express credit facilities has not met its obligations to lend under those agreements. Thus, it is likely that the available capacity of each of the three facilities (ours, Rockies Express, and Midcontinent Express) will be reduced by the Lehman commitment. The commitments of the other banks remain unchanged, and the facilities are not defaulted.

Also, on October 12, 2008, the U.S. Federal Reserve approved the application of Wells Fargo & Company to acquire Wachovia Corporation and its subsidiary banks. Earlier, on October 9, 2008, Wells Fargo had reaffirmed that it was proceeding with its merger with Wachovia as a whole company transaction with all of Wachovia's banking and other operations, requiring no financial assistance from the Federal Deposit Insurance Corporation or

any other U.S. government agency. Wells Fargo will acquire all of Wachovia Corporation and all its businesses and obligations, including its preferred equity and indebtedness, and all its banking deposits. Wachovia Bank, National Association is the administrative agent of our five-year unsecured credit facility, and we do not expect that this merger will adversely impact our access to capital.

Long-term Financing

In addition to our principal sources of short-term liquidity listed above, we could meet our cash requirements (other than distributions to our common unitholders, Class B unitholders and general partner) through issuing long-term notes or additional common units, or by utilizing the proceeds from purchases of additional i-units by KMR with the proceeds from issuances of KMR shares. Furthermore, at Knight's third quarter board meeting on October 15, 2008, Knight's board indicated its willingness to contribute up to $750 million of equity to us over the next 18 months, if necessary, in order to support our capital raising efforts.

On February 12, 2008, we completed both a public offering of senior notes and a privately negotiated offering of 1,080,000 of our common units. We issued a total of $900 million in principal amount of senior notes in the public offering, consisting of $600 million of 5.95% notes due February 15, 2018, and $300 million of 6.95% notes due January 15, 2038. We received proceeds from the issuance of the notes, after underwriting discounts and commissions, of approximately $894.1 million, and we used the proceeds to reduce the borrowings under our commercial paper program. We issued the 1,080,000 common units on February 12, 2008 at a price of $55.65 per unit in a privately negotiated transaction with two investors. We received net proceeds of $60.1 million for the issuance of these common units, and we used the proceeds to reduce the borrowings under our commercial paper program.

On March 3, 2008, we issued 5,000,000 of our common units in a public offering at a price of $57.70, less commissions and underwriting expenses. At the time of the offering, we granted the underwriters a 30-day option to purchase up to an additional 750,000 common units from us on the same terms and conditions, and we issued an additional 750,000 common units on March 10, 2008 upon exercise of this option. After commissions and underwriting expenses, we received net proceeds of $324.2 million for the issuance of these 5,750,000 common units, and we used the proceeds to reduce the borrowings under our commercial paper program.

On June 6, 2008, we completed an additional public offering of senior notes. We issued a total of $700 million in principal amount of senior notes, consisting of $375 million of 5.95% notes due February 15, 2018, and $325 million of 6.95% notes due January 15, 2038. We received proceeds from the issuance of the notes, after underwriting discounts and commissions, of approximately $687.7 million, and we used the proceeds to reduce the borrowings under our commercial paper program.

On September 19, 2008, we filed a registration statement with the Securities and Exchange Commission ("SEC") under The Securities Act of 1933 on Form S-3. This registration statement, commonly referred to as a shelf registration statement, will allow us to sell up to $5 billion of additional common units or debt securities. The shelf registration statement is intended to provide us with flexibility to raise funds from the offering of our securities in one or more offerings, in amounts, and at prices to be set forth in subsequent filings made with the SEC at the time of each separate offering. Our offerings would be subject to market conditions and our capital needs, and unless we specify otherwise in a prospectus supplement, we intend to use the net proceeds from the sale of offered securities for general partnership purposes. This may include, among other things, additions to working capital, repayment or refinancing of existing indebtedness or other partnership obligations, financing of capital expenditures and acquisitions, investment in existing and future projects, and repurchases and redemptions of securities. Pending any specific application, we may initially invest funds in short-term marketable securities or apply them to the reduction of other indebtedness. As of the date of the filing of this report, the Form S-3 had not yet been declared effective by the SEC.

As of September 30, 2008, our total liability balance due on the various series of our senior notes was $7,881.1 million, and the total liability balance due on the various borrowings of our operating partnerships and subsidiaries was $164.8 million. We are subject to changes in the equity and debt markets for our limited partner units and long-term notes, and there can be no assurance we will be able or willing to access the public or private markets for our limited partner units and/or long-term notes in the future. If we were unable or unwilling to issue additional limited partner units, we would be required to either restrict potential future acquisitions or pursue other debt financing alternatives, some of which could involve higher costs or negatively affect our credit ratings. Our ability to access the public and private debt markets is affected by our credit ratings. See "—Capital Structure" above for a discussion of our credit ratings. For additional information regarding our debt securities and credit facility, see Note 9 to our consolidated financial statements included in our 2007 Form 10-K.

Capital Expenditures

Our sustaining capital expenditures for the nine months ended September 30, 2008 were $120.1 million, and we expect to spend another $85.1 million during the final quarter of 2008 (including $11.3 million for hurricane and fire repair and replacement costs). Our sustaining capital expenditures are funded with cash flows from operations.

Our discretionary capital expenditures for the nine months ended September 30, 2008 were $1,794.3 million and we expect to spend another $545 million during the final quarter of 2008. In addition to our consolidated capital expenditures, we expect to spend approximately $1.4 billion for our share of expansion capital expenditures for both the Rockies Express and Midcontinent Express natural gas pipeline projects. Our share of the capital expenditures for these projects are being funded by borrowings under Rockies Express' and Midcontinent Express' own revolving credit facilities or by those entities issuing short-term commercial paper or long-term notes and a $306 million equity infusion by us. We have funded our discretionary capital expenditures and our $306 million equity infusion noted above through borrowings under our $1.85 billion revolving credit facility and by issuing short-term commercial paper. To the extent these sources are not sufficient, we will fund additional amounts through the issuance of long-term notes or common units for cash. During 2008, we have used sales of long-term notes and common units to refinance portions of our short-term borrowings.

Operating Activities

Net cash provided by operating activities was $1,433.1 million for the nine months ended September 30, 2008, versus $1,254.7 million for the comparable period of 2007. The period-to-period increase of $178.4 million (14%) in cash provided by operating activities consisted of:

- a $380.2 million increase in cash from overall higher partnership income—after adding back non-cash items including, among other things, a $377.1 million goodwill impairment charge recognized in the first quarter of 2007. The higher partnership income reflects the increase in cash earnings from our five reportable business segments in the first nine months of 2008, as discussed above in "—Results of Operations;"

- a $27.4 million increase related to higher distributions received from equity investments—chiefly due to $54.6 million of initial distributions received in 2008 from our investment in West2East Pipeline LLC, the sole owner of Rockies Express Pipeline LLC. Currently, we own a 51% equity interest in West2East Pipeline LLC, and when construction of the Rockies Express Pipeline is completed, our ownership interest will be reduced to 50% and the capital accounts of West2East Pipeline LLC will be trued-up to reflect our 50% economic interest in the project.

  The overall increase in period-to-period distributions from equity investments includes a $31.2 million decrease in distributions received from the Red Cedar Gathering Company. In the first quarter of 2007, Red Cedar distributed to us $32.6 million following a refinancing of its long-term debt obligations. Red Cedar used the proceeds received from the March 2007 sale of unsecured senior notes to refund and retire the outstanding balance on its then-existing senior notes, and to make a distribution to its two owners;

- a $186.7 million decrease in cash inflows relative to net changes in working capital items, mainly due to a $178.2 million decrease from the collection and payment of trade and related party receivables and payables. This decrease was largely due to timing differences from the collection of trade and related party receivables—reflecting both higher receivable balances in 2008 and higher collections of year-end accounts receivable balances in the first nine months of 2007, versus the first nine months of 2008;

- a $16.8 million decrease in cash inflows relative to changes in other non-current assets and liabilities, and other incremental non-cash expenses, including higher non-cash general and administrative expenses in 2007

related to the activities required to complete KMI's going-private transaction (with regard to the going-private transaction expenses, for accounting purposes, Knight was required to allocate to us a portion of these transaction-related amounts and we were required to recognize the amounts as expense on our income statements; however, we were not responsible for paying these buyout expenses, and accordingly, recognized the unpaid amount as both a contribution to "Partners' Capital" and an increase to "Minority interest" on our balance sheet);

- a $15.0 million decrease in cash from an interest rate swap termination payment we received in March 2007, when we terminated a fixed-to-floating interest rate swap agreement having a notional principal amount of $100 million and a maturity date of March 15, 2032; and

- a $10.7 million decrease in cash from FERC-mandated reparation payment and reserve adjustments. In March 2008, pursuant to FERC orders, we made reparation payments of $23.3 million to certain shippers on our Pacific operations' pipelines and we reduced our rate case liability. The payment primarily related to a FERC ruling in February 2008 that resolved certain challenges by complainants with regard to delivery tariffs and gathering enhancement fees at our Pacific operations' Watson Station, located in Carson, California. In September 2008, we increased our legal reserve by $12.6 million, an adjustment related to proposed legal settlements reached with certain shippers on our Pacific operations' East Line pipeline.

Investing Activities

Net cash used in investing activities was $2,065.9 million for the nine month period ended September 30, 2008, compared to $1,908.7 million for the comparable 2007 period. The $157.2 million (8%) increase in cash used in investing activities was primarily attributable to:

- a $771.5 million increase from higher capital expenditures—largely due to increased investment undertaken to construct our Kinder Morgan Louisiana Pipeline, expand our Trans Mountain crude oil and refined petroleum products pipeline system, and add infrastructure to our carbon dioxide producing and delivery operations.

  Since the end of 2007, rising construction costs, additional regulatory requirements, and certain weather delays have continued to create a challenging business environment, and our total forecasted capital expenditures on our major projects have increased by approximately 22% from the projection we made at the beginning of 2008. Most of this increase has been on our natural gas pipeline major projects—for example, market conditions for consumables, labor and construction equipment along with certain provisions in the final environmental impact statement have resulted in increased construction costs for the Rockies Express Pipeline. Our current estimate of total construction costs for the entire Rockies Express pipeline project is now approximately $6.0 billion (consistent with our October 15, 2008 third quarter earnings press release). We continue to be focused on managing these cost increases in order to complete our expansion projects as close to on-time and on-budget as possible, and we attempt to identify ancillary opportunities to increase our returns where possible.

  Our sustaining capital expenditures, defined as capital expenditures which do not increase the capacity of an asset, were $120.1 million for the first nine months of 2008, compared to $95.0 million for the first nine months of 2007. The above amounts include our proportionate share of Rockies Express' sustaining capital expenditures—less than $0.1 million in 2008 and none in 2007—but do not include the sustaining capital expenditures of our Trans Mountain pipeline system for periods prior to our acquisition date of April 30, 2007. Generally, we fund our sustaining capital expenditures with existing cash or from cash flows from operations. In addition to utilizing cash generated from its operations, Rockies Express can fund its cash requirements for capital expenditures through borrowings under its own credit facility, issuing its own short-term commercial paper or long-term notes, or with proceeds from contributions received from its member owners.

  Additionally, our forecasted expenditures for the remaining three months of 2008 for sustaining capital expenditures are approximately $85.1 million (including less than $0.1 million for our proportionate share of Rockies Express, but including $11.3 million for hurricane and fire repair and replacement costs). All of our capital expenditures, with the exception of sustaining capital expenditures, are discretionary, and our discretionary capital expenditures—including expenditures for internal expansion

projects—totaled $1,794.3 million for the first nine months of 2008 and $1,047.9 million for the first nine months of 2007;

- a $295.0 million increase in cash used from incremental contributions to equity investments in the first nine months of 2008, largely driven by a $306.0 million equity investment paid in February 2008 to West2East Pipeline LLC, and partially offset by a $10.6 million drop in contributions to Midcontinent Express Pipeline LLC, the sole owner of the Midcontinent Express Pipeline. In the first nine months of 2008 and 2007, we contributed $27.5 million and $38.1 million, respectively, for our share of Midcontinent Express Pipeline construction costs. We own a 50% equity interest in the approximately $1.9 billion, 500-mile interstate natural gas pipeline that will extend between Bennington, Oklahoma and Butler, Alabama;

- a $572.5 million decrease in cash used related to our acquisition of Trans Mountain from Knight. Through September 2007, we paid $549.1 million to Knight to acquire the net assets of Trans Mountain, and in April 2008, we received a cash contribution of $23.4 million from Knight as a result of certain true-up provisions in our acquisition agreement. For more information on our acquisition of Trans Mountain from Knight, see Note 2 to our consolidated financial statements included elsewhere in this report;

- a $152.7 million decrease in cash used due to lower expenditures made for strategic business acquisitions. In the first nine months of 2008, our cash outlays for additional net assets and investments totaled $9.0 million, consisting of $16.4 million paid for additional bulk and liquid terminal assets, less $7.4 million we received as the beginning cash balance of the Express and Jet Fuel pipeline systems, acquired from Knight on August 28, 2008 (also discussed in Note 2). Excluding amounts paid for Trans Mountain (discussed above), in the first nine months of 2007, our payments for acquired assets and investments totaled $161.7 million, including $100.3 million paid for our purchase of terminal assets from Marine Terminals, Inc. and $38.3 million paid for our purchase of the Vancouver Wharves bulk marine terminal from the British Columbia Railway Company;

- an $89.1 million decrease in cash used related to a return of capital received from Midcontinent Express Pipeline LLC in the first quarter of 2008. In February 2008, Midcontinent entered into and then made borrowings under a new $1.4 billion three-year, unsecured revolving credit facility due February 28, 2011. Midcontinent then made distributions (in excess of cumulative earnings) to its two member owners to reimburse them for prior contributions made to fund its pipeline construction costs;

- an $80.6 million decrease in cash used due to lower period-to-period payments for margin and restricted deposits in 2008 compared to 2007, associated largely with our utilization of derivative contracts to hedge (offset) against the volatility of energy commodity price risks; and

- a $37.2 million decrease in cash used, relative to 2007, due to higher net proceeds received from the sales of investments, property, plant and equipment, and other net assets (net of salvage and removal costs). The increase in cash sales proceeds was driven by the approximately $50.7 million we received in the second quarter of 2008 for the sale of our 25% equity ownership interest in Thunder Creek Gas Services, LLC (discussed in Note 2 to our consolidated financial statements included elsewhere in this report).

Financing Activities

Net cash provided by financing activities amounted to $629.7 million for the first nine months of 2008. For the same nine month period last year, our financing activities provided net cash of $703.2 million. The $73.5 million (10%) cash decrease from the comparable 2007 period was primarily due to:

- a $244.0 million decrease in cash from higher partnership distributions in the first nine months of 2008, when compared to the first nine months of 2007. Distributions to all partners, consisting of our common and Class B unitholders, our general partner and our minority interests, totaled $1,088.6 million in the first nine months of 2008, compared to $844.6 million in the same period a year earlier;

- an $86.4 million increase in cash inflows from partnership equity issuances. The increase relates to the combined $384.3 million we received from the two separate offerings of additional common units in the first

nine months of 2008 (discussed above in "—Long-term Financing"), versus the $297.9 million we received, after commissions and underwriting expenses, in May 2007 for our issuance of an additional 5,700,000 i-units to KMR;

- a $61.0 million increase in cash inflows from net changes in cash book overdrafts—resulting from timing differences on checks issued but not yet endorsed; and

- an $18.2 million increase in cash from overall debt financing activities—which include our issuances and payments of debt and our debt issuance costs. The period-to-period increase in cash from overall financing activities was primarily due to (i) a $295.0 million increase in cash inflows from incremental borrowings under our long-term revolving bank credit facility in the first nine months of 2008; (ii) a $202.7 million decrease in cash inflows due to lower net issuances and payments of senior notes in the first nine months of 2008; (iii) a $67.3 million decrease in cash inflows from lower overall net commercial paper borrowings in the first nine months of 2008; and (iv) a $5.2 million decrease in cash from our September 2008 principal payment of tax-exempt bonds issued by the Jackson-Union Counties Regional Port District (our subsidiary, Kinder Morgan Operating L.P. "B" is the obligor of these bonds and the remaining principal amount of $18.5 million is due April 1, 2024).

  The increase in cash from borrowings under our five-year unsecured bank credit facility was based in part, on period-to-period changes in interest rates, and in part to a general outflow of cash invested in the U.S. commercial paper market during the first nine months of 2008. In the third quarter of 2008, we elected to borrow funds under our credit facility (that remains due August 18, 2010), taking advantage of favorable changes between the variable interest rates obtainable pursuant to the provisions of the credit facility on the one hand, and the variable rates obtainable in the commercial paper market on the other hand.

The decrease in cash from changes in senior notes outstanding reflects the combined $1,581.8 million we received from our February and June 2008 public offerings of senior notes (discussed in Note 7 to our consolidated financial statements included elsewhere in this report), versus the $1,784.5 million increase in cash inflows from the issuances and payments of senior notes during the first nine months of 2007. During the nine month 2007 period, we both repaid $250 million of 5.35% senior notes that matured on August 15, 2007, and completed offerings for an aggregate $2.05 billion in principal amount of senior notes in four separate series: (i) $600 million of 6.00% notes due February 1, 2017; (ii) $400 million of 6.50% notes due February 1, 2037; (iii) $550 million of 6.95% notes due January 15, 2038; and (iv) $500 million of 5.85% notes due September 15, 2012. Combined, we received proceeds, net of underwriting discounts and commissions, of $2,034.5 million from these long-term debt offerings and we used the proceeds from each of these offerings, and the proceeds received from our 2008 debt offerings, to reduce the borrowings under our commercial paper program.

Partnership Distributions

Our partnership agreement requires that we distribute 100% of "Available Cash," as defined in our partnership agreement, to our partners within 45 days following the end of each calendar quarter in accordance with their respective percentage interests. Our 2007 Form 10-K contains additional information concerning our partnership distributions, including the definition of "Available Cash," the manner in which our total distributions are divided between our general partner and our limited partners, and the form of distributions to all of our partners, including minority interests.

As discussed in Note 2 to our consolidated financial statements included elsewhere in this report, the transactions, balances and results of operations of our Trans Mountain pipeline system were included in our consolidated financial information as if it had been transferred to us on January 1, 2006; however, the effective date of this acquisition was April 30, 2007, and the acquisition had no impact on the distributions we made (including incentive distributions paid to our general partner) prior to this date.

On August 14, 2008, we paid a quarterly distribution of $0.99 per unit for the second quarter of 2008. This distribution was 16% greater than the $0.85 distribution per unit we paid in August 2007 for the second quarter of 2007. We paid this distribution in cash to our general partner and to our common and Class B unitholders. KMR, our sole i-unitholder, received additional i-units based on the $0.99 cash distribution per common unit. We believe that future operating results will continue to support similar levels of quarterly cash and i-unit distributions; however, no assurance can be given that future distributions will continue at such levels.

On October 15, 2008, we declared a cash distribution of $1.02 per unit for the third quarter of 2008 (an annualized rate of $4.08 per unit). This distribution was 16% higher than the $0.88 per unit distribution we made for the third quarter of 2007. In November 2007, we announced that we expected to declare cash distributions of $4.02 per unit for 2008, an almost 16% increase over our cash distributions of $3.48 per unit for 2007. We currently expect to meet or exceed this distribution target for 2008; however, no assurance can be given that we will be able to meet or exceed this level of distribution, and our expectation does not take into account any capital costs associated with financing the payment of reparations sought by shippers on our Pacific operations' interstate pipelines.

The incentive distribution that we paid on August 14, 2008 to our general partner (for the second quarter of 2008) was $194.2 million. Our general partner's incentive distribution that we paid in August 2007 (for the second quarter of 2007) was $147.6 million. Our general partner's incentive distribution for the distribution that we declared for the third quarter of 2008 will be $204.3 million, and our general partner's incentive distribution for the distribution that we paid for the third quarter of 2007 was $155.2 million. The period-to-period increases in our general partner incentive distributions resulted from both increased cash distributions per unit and increases in the number of common units and i-units outstanding.

Litigation and Environmental

As of September 30, 2008, we have recorded a total reserve for environmental claims, without discounting and without regard to anticipated insurance recoveries, in the amount of $72.1 million. In addition, we have recorded a receivable of $24.5 million for expected cost recoveries that have been deemed probable. As of December 31, 2007, our environmental reserve totaled $92.0 million and our estimated receivable for environmental cost recoveries totaled $37.8 million, respectively. The reserve is primarily established to address and clean up soil and ground water impacts from former releases to the environment at facilities we have acquired or accidental spills or releases at facilities that we own. Reserves for each project are generally established by reviewing existing documents, conducting interviews and performing site inspections to determine the overall size and impact to the environment. Reviews are made on a quarterly basis to determine the status of the cleanup and the costs associated with the effort. In assessing environmental risks in conjunction with proposed acquisitions, we review records relating to environmental issues, conduct site inspections, interview employees, and, if appropriate, collect soil and groundwater samples.

Additionally, as of September 30, 2008, and December 31, 2007, we have recorded a total reserve for legal fees, transportation rate cases and other litigation liabilities in the amount of $232.5 million and $247.9 million, respectively. The reserve is primarily related to various claims from lawsuits arising from our Pacific operations, and the contingent amount is based on both the circumstances of probability and reasonability of dollar estimates. We regularly assess the likelihood of adverse outcomes resulting from these claims in order to determine the adequacy of our liability provision.

Though no assurance can be given, we believe we have established adequate environmental and legal reserves such that the resolution of pending environmental matters and litigation will not have a material adverse impact on our business, cash flows, financial position or results of operations. However, changing circumstances could cause these matters to have a material adverse impact.

Pursuant to our continuing commitment to operational excellence and our focus on safe, reliable operations, we have implemented, and intend to implement in the future, enhancements to certain of our operational practices in order to strengthen our environmental and asset integrity performance. These enhancements have resulted and may result in higher operating costs and sustaining capital expenditures; however, we believe these enhancements will provide us the greater long term benefits of improved environmental and asset integrity performance.

Please refer to Note 3 to our consolidated financial statements included elsewhere in this report for additional information regarding pending litigation, environmental and asset integrity matters.

Certain Contractual Obligations

Except as set forth under "—Midcontinent Express Pipeline LLC Debt" and under "—Senior Notes" in Note 7 to our consolidated financial statements included elsewhere in this report, there have been no material changes in our contractual obligations that would affect the disclosures presented as of December 31, 2007 in our 2007 Form 10-K.

Off Balance Sheet Arrangements

Except as set forth under "—Midcontinent Express Pipeline LLC Debt" in Note 7 to our consolidated financial statements included elsewhere in this report, there have been no material changes in our obligations with respect to other entities that are not consolidated in our financial statements that would affect the disclosures presented as of December 31, 2007 in our 2007 Form 10-K.

Fair Value Measurements

SFAS No. 157 established a hierarchal disclosure framework associated with the level of pricing observability utilized in measuring fair value. This framework defined three levels of inputs to the fair value measurement process, and requires that each fair value measurement be assigned to a level corresponding to the lowest level input that is significant to the fair value measurement in its entirety. We utilize energy commodity derivative contracts for the purpose of mitigating our risk resulting from fluctuations in the market price of natural gas, natural gas liquids and crude oil, and utilize interest rate swaps to mitigate our risk from fluctuations in interest rates. For more information on our risk management activities, see Note 10 to our consolidated financial statements included elsewhere in this report.

At September 30, 2008, the fair value of our derivative contracts classified as level 3 under the fair value hierarchy consisted primarily of West Texas Sour Hedges and West Texas Intermediate options (costless collars). Costless collars are designed to establish floor and ceiling prices on anticipated future oil production from the assets we own in the SACROC oil field. While the use of these derivative contracts limits the downside risk of adverse price movements, they may also limit future revenues from favorable price movements. In addition to these oil-commodity derivatives, level 3 derivative contracts consist of Natural Gas Basis swaps. Basis swaps are used in connection with another derivative contract to reduce hedge ineffectiveness by reducing a basis difference between a hedged exposure and a derivative contract. The following table summarizes the total fair value asset and liability measurements of our level 3 energy commodity derivative contracts in accordance with SFAS No. 157.

	Significant Unobservable Inputs (Level 3)					
	Assets			Liabilities		
	September 30, 2008	December 31, 2007	Change	September 30, 2008	December 31, 2007	Change
Natural Gas Basis Swaps	$ 4.9	$ 2.8	$ 2.1	$ (7.0)	$ (4.7)	$ (2.3)
WTS Oil Swaps	—	—	—	(90.1)	(94.5)	4.4
WTI Options	46.7	0.0	46.7	(28.7)	0.0	(28.7)
Other	1.0	1.0	—	(7.4)	(4.9)	(2.5)
Total	$ 52.6	$ 3.8	$ 48.8	$ (133.2)	$ (104.1)	$ (29.1)

The largest change in fair value of level 3 assets and liabilities between December 31, 2007 and September 30, 2008 is related to WTI Options, which amount to an increase of $46.7 million and $28.7 million in assets and liabilities, respectively. The majority of these contracts were entered into during 2008, which account for the change. There were no transfers into or out of level 3 during the period.

The valuation techniques used for the above Level 3 input derivatives are as follows:

- Natural Gas Basis Swaps: values obtained through a pricing service, derived by combining raw inputs from NYMEX with proprietary quantitative models and processes. Although the prices are originating from a liquid market (NYMEX), we believe the incremental effort to further validate these prices would take undue effort and would not materially alter the assumptions. As a result, we have classified the valuation of these derivatives as level 3;

- WTS Oil Swaps: prices obtained from a broker using their proprietary model for similar assets and liabilities, quotes are non-binding; and

- WTI Options: valued using internal model. Internal models incorporate the use of options pricing and estimates of the present value of cash flows based upon underlying contractual terms. The models reflect management's estimates, taking into account observable market prices, estimated market prices in the absence of quoted market prices, the risk-free market discount rate, volatility factors, estimated correlations of commodity prices and contractual volumes.

Commodity derivative contracts are recorded at their estimated fair values as of each reporting date. For commodity derivatives, the most observable inputs available are used to determine the fair value of each contract. In the absence of a quoted price for an identical contract in an active market, we use broker quotes for identical or similar contracts, or internally prepared valuation models as primary inputs to determine fair value. No adjustments were made to quotes or prices obtained from brokers and pricing services. Valuation methods have not changed during the quarter ended September 30, 2008.

When appropriate, valuations are adjusted for various factors including credit considerations. Such adjustments are generally based on available market evidence, including but not limited to our credit default swap quotes as of September 30, 2008. Collateral agreements with our counterparties serve to reduce our credit exposure and are considered in the adjustment. Our fair value measurements of derivative contracts are adjusted for credit risk in accordance with SFAS No. 157, and as of September 30, 2008, our consolidated “Accumulated other comprehensive loss” balance includes a gain of $14.1 million related to discounting the value of our energy commodity derivative liabilities for the effect of credit risk. Additionally, we considered the value of our derivative assets, and the associated counterparty credit risk, and determined that a reserve against these assets is not necessary.

With the exception of the Casper and Douglas hedges and the ineffective portion of our derivative contracts, our energy commodity derivative contracts are accounted for as cash flow hedges. In accordance with SFAS No. 133, gains and losses associated with cash flow hedges are reported in “Accumulated other comprehensive loss” in our accompanying consolidated balance sheets.

Information Regarding Forward-Looking Statements

This filing includes forward-looking statements. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. They use words such as “anticipate,” “believe,” “intend,” “plan,” “projection,” “forecast,” “strategy,” “position,” “continue,” “estimate,” “expect,” “may,” or the negative of those terms or other variations of them or comparable terminology. In particular, statements, express or implied, concerning future actions, conditions or events, future operating results or the ability to generate sales, income or cash flow or to make distributions are forward-looking statements. Forward-looking statements are not guarantees of performance. They involve risks, uncertainties and assumptions. Future actions, conditions or events and future results of operations may differ materially from those expressed in these forward-looking statements. Many of the factors that will determine these results are beyond our ability to control or predict. Specific factors which could cause actual results to differ from those in the forward-looking statements include:

- price trends and overall demand for natural gas liquids, refined petroleum products, oil, carbon dioxide, natural gas, electricity, coal and other bulk materials and chemicals in North America;
- economic activity, weather, alternative energy sources, conservation and technological advances that may affect price trends and demand;
- changes in our tariff rates implemented by the Federal Energy Regulatory Commission or the California Public Utilities Commission;

- our ability to acquire new businesses and assets and integrate those operations into our existing operations, as well as our ability to expand our facilities;
- difficulties or delays experienced by railroads, barges, trucks, ships or pipelines in delivering products to or from our terminals or pipelines;
- our ability to successfully identify and close acquisitions and make cost-saving changes in operations;
- shut-downs or cutbacks at major refineries, petrochemical or chemical plants, ports, utilities, military bases or other businesses that use our services or provide services or products to us;
- crude oil and natural gas production from exploration and production areas that we serve, such as the Permian Basin area of West Texas, the U.S. Rocky Mountains and the Alberta oil sands;
- changes in laws or regulations, third-party relations and approvals, and decisions of courts, regulators and governmental bodies that may adversely affect our business or our ability to compete;
- changes in accounting pronouncements that impact the measurement of our results of operations, the timing of when such measurements are to be made and recorded, and the disclosures surrounding these activities;
- our ability to offer and sell equity securities and debt securities or obtain debt financing in sufficient amounts to implement that portion of our business plan that contemplates growth through acquisitions of operating businesses and assets and expansions of our facilities;
- our indebtedness, which could make us vulnerable to general adverse economic and industry conditions, limit our ability to borrow additional funds, and/or place us at competitive disadvantages compared to our competitors that have less debt or have other adverse consequences;
- interruptions of electric power supply to our facilities due to natural disasters, power shortages, strikes, riots, terrorism, war or other causes;
- our ability to obtain insurance coverage without significant levels of self-retention of risk;
- acts of nature, sabotage, terrorism or other similar acts causing damage greater than our insurance coverage limits;
- capital and credit markets conditions, inflation and interest rates;
- the political and economic stability of the oil producing nations of the world;
- national, international, regional and local economic, competitive and regulatory conditions and developments;
- our ability to achieve cost savings and revenue growth;
- foreign exchange fluctuations;
- the timing and extent of changes in commodity prices for oil, natural gas, electricity and certain agricultural products;
- the extent of our success in discovering, developing and producing oil and gas reserves, including the risks inherent in exploration and development drilling, well completion and other development activities;
- engineering and mechanical or technological difficulties that we may experience with operational equipment, in well completions and workovers, and in drilling new wells;

- the uncertainty inherent in estimating future oil and natural gas production or reserves;
- the ability to complete expansion projects on time and on budget;
- the timing and success of our business development efforts; and
- unfavorable results of litigation and the fruition of contingencies referred to in Note 3 to our consolidated financial statements included elsewhere in this report.

There is no assurance that any of the actions, events or results of the forward-looking statements will occur, or if any of them do, what impact they will have on our results of operations or financial condition. Because of these uncertainties, you should not put undue reliance on any forward-looking statements.

See Item 1A "Risk Factors" of our 2007 Form 10-K, and Part II, Item 1A "Risk Factors" of this report for a more detailed description of these and other factors that may affect the forward-looking statements. When considering forward-looking statements, one should keep in mind the risk factors described in both our 2007 Form 10-K and this report. The risk factors could cause our actual results to differ materially from those contained in any forward-looking statement. We disclaim any obligation, other than as required by applicable law, to update the above list or to announce publicly the result of any revisions to any of the forward-looking statements to reflect future events or developments.

Item 3. Quantitative and Qualitative Disclosures About Market Risk.

There have been no material changes in market risk exposures that would affect the quantitative and qualitative disclosures presented as of December 31, 2007, in Item 7A of our 2007 Form 10-K. However, the capital and credit markets have been experiencing extreme volatility and disruption for more than 12 months, and in recent weeks, the volatility and disruption have reached unprecedented levels. See Part II, Item 1A "Risk Factors" of this report for a more detailed description of this and other factors that may affect our overall business growth. For more information on our risk management activities, see Note 10 to our consolidated financial statements included elsewhere in this report.

Item 4. Controls and Procedures.

As of September 30, 2008, our management, including our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15(b) under the Securities Exchange Act of 1934. There are inherent limitations to the effectiveness of any system of disclosure controls and procedures, including the possibility of human error and the circumvention or overriding of the controls and procedures. Accordingly, even effective disclosure controls and procedures can only provide reasonable assurance of achieving their control objectives. Based upon and as of the date of the evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that the design and operation of our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed in the reports we file and submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported as and when required, and is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. There has been no change in our internal control over financial reporting during the quarter ended September 30, 2008 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings.

See Part I, Item 1, Note 3 to our consolidated financial statements entitled "Litigation, Environmental and Other Contingencies," which is incorporated in this item by reference.

Item 1A. Risk Factors.

Except as set forth below, there have been no material changes in or additions to the risk factors disclosed in Item 1A "Risk Factors" in our 2007 Form 10-K.

Current levels of market volatility are unprecedented.

The capital and credit markets have been experiencing extreme volatility and disruption for more than 12 months. In recent weeks, the volatility and disruption have reached unprecedented levels. In some cases, the markets have exerted downward pressure on stock prices and credit capacity for certain issuers. Our plans for growth require regular access to the capital and credit markets. If current levels of market disruption and volatility continue or worsen, access to capital and credit markets could be disrupted making growth through acquisitions and development projects difficult or impractical to pursue until such time as markets stabilize.

Our operating results may be adversely affected by unfavorable economic and market conditions.

Economic conditions worldwide have from time to time contributed to slowdowns in the oil and gas industry, as well as in the specific segments and markets in which we operate, resulting in reduced demand and increased price competition for our products and services. Our operating results in one or more geographic regions may also be affected by uncertain or changing economic conditions within that region, such as the challenges that are currently affecting economic conditions in the United States. Volatility in commodity prices might have an impact on many of our customers, which in turn could have a negative impact on their ability to meet their obligations to us. In addition, decreases in the prices of crude oil and natural gas liquids will have a negative impact on the results of our CO_2 business segment. If global economic and market conditions (including volatility in commodity markets), or economic conditions in the United States or other key markets, remain uncertain or persist, spread or deteriorate further, we may experience material impacts on our business, financial condition and results of operations.

The recent downturn in the credit markets has increased the cost of borrowing and has made financing difficult to obtain, each of which may have a material adverse effect on our results of operations and business.

Recent events in the financial markets have had an adverse impact on the credit markets and, as a result, the availability of credit has become more expensive and difficult to obtain. Some lenders are imposing more stringent restrictions on the terms of credit and there may be a general reduction in the amount of credit available in the markets in which we conduct business. In addition, as a result of the current credit market conditions and the recent downgrade of our short-term credit ratings by Standard & Poor's Rating Services, we are currently unable to access commercial paper borrowings and instead are meeting our financing and liquidity needs through borrowings under our bank credit facility. The negative impact on the tightening of the credit markets may have a material adverse effect on us resulting from, but not limited to, an inability to expand facilities or finance the acquisition of assets on favorable terms, if at all, increased financing costs or financing with increasingly restrictive covenants.

The failure of any bank in which we deposit our funds could reduce the amount of cash we have available for operations, to pay distributions and to make additional investments.

We have diversified our cash and cash equivalents between several banking institutions in an attempt to minimize exposure to any one of these entities. However, the Federal Deposit Insurance Corporation, or "FDIC," only insures amounts up to $250,000 per depositor per insured bank. We currently have cash and cash equivalents and restricted cash deposited in certain financial institutions in excess of federally insured levels. If any of the banking institutions in which we have deposited funds ultimately fails, we may lose our deposits over $250,000.

The loss of our deposits could reduce the amount of cash we have available to distribute or invest and could result in a decline in the value of your investment.

There can be no assurance as to the impact on the financial markets of the U.S. government's plan to purchase large amounts of illiquid, mortgage-backed and other securities from financial institutions.

In response to the financial crises affecting the banking system and financial markets and going concern threats to investment banks and other financial institutions, President Bush signed the Emergency Economic Stabilization Act of 2008, referred to as the EESA in this report, into law on October 3, 2008. Pursuant to the EESA, the U.S. Treasury has the authority to, among other things, purchase up to $700 billion of mortgage-backed and other securities from financial institutions for the purpose of stabilizing the financial markets. There can be no assurance what impact the EESA will have on the financial markets, including the extreme levels of volatility currently being experienced. Although we are not one of the institutions that will sell securities to the U.S. Treasury pursuant to the EESA, the ultimate effects of the EESA on the financial markets and the economy in general could materially and adversely affect our business, financial condition and results of operations, or the trading price of our common units.

Our business is subject to extensive regulation that affects our operations and costs.

Our assets and operations are subject to regulation by federal, state, provincial and local authorities, including regulation by the FERC, and by various authorities under federal, state and local environmental, human health and safety and pipeline safety laws. Regulation affects almost every aspect of our business, including, among other things, our ability to determine terms and rates for our interstate pipeline services, to make acquisitions or to build extensions of existing facilities. The costs of complying with such laws and regulations are already significant, and additional or more stringent regulation could have a material adverse impact on our business, financial condition and results of operations.

In addition, regulators have taken actions designed to enhance market forces in the gas pipeline industry, which have led to increased competition. In a number of U.S. markets, natural gas interstate pipelines face competitive pressure from a number of new industry participants, such as alternative suppliers, as well as traditional pipeline competitors. Increased competition driven by regulatory changes could have a material impact on business in our markets and therefore adversely affect our financial condition and results of operations.

Environmental laws and regulations could expose us to significant costs and liabilities.

Our operations are subject to federal, state, provincial and local laws, regulations and potential liabilities arising under or relating to the protection or preservation of the environment, natural resources and human health and safety. Such laws and regulations affect many aspects of our present and future operations, and generally require us to obtain and comply with various environmental registrations, licenses, permits, inspections and other approvals. Liability under such laws and regulations may be incurred without regard to fault under the Comprehensive Environmental Response, Compensation, and Liability Act, commonly known as CERCLA or Superfund, the Resource Conservation and Recovery Act, commonly known as RCRA, or analogous state laws for the remediation of contaminated areas. Private parties, including the owners of properties through which our pipelines pass may also have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with such laws and regulations or for personal injury or property damage. Our insurance may not cover all environmental risks and costs or may not provide sufficient coverage in the event an environmental claim is made against us.

Failure to comply with these laws and regulations may expose us to civil, criminal and administrative fines, penalties and/or interruptions in our operations that could influence our results of operations. For example, if an accidental leak, release or spill of liquid petroleum products, chemicals or other hazardous substances occurs at or from our pipelines or our storage or other facilities, we may experience significant operational disruptions and we may have to pay a significant amount to clean up the leak, release or spill, pay for government penalties, address natural resource damage, compensate for human exposure or property damage, install costly pollution control equipment or a combination of these and other measures. The resulting costs and liabilities could materially and negatively affect our level of earnings and cash flows. In addition, emission controls required under the Federal Clean Air Act and other similar federal, state and provincial laws could require significant capital expenditures at our facilities.

We own and/or operate numerous properties that have been used for many years in connection with our business activities. While we have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other hazardous substances may have been released at or from properties owned, operated or used by us or our predecessors, or at or from properties where our or our predecessors' wastes have been taken for disposal. In addition, many of these properties have been owned and/or operated by third parties whose management, handling and disposal of hydrocarbons or other hazardous substances were not under our control. These properties and the hazardous substances released and wastes disposed on them may be subject to laws in the United States such as CERCLA, which impose joint and several liability without regard to fault or the legality of the original conduct. Under the regulatory schemes of the various Canadian provinces, such as British Columbia's Environmental Management Act, Canada has similar laws with respect to properties owned, operated or used by us or our predecessors. Under such laws and implementing regulations, we could be required to remove or remediate previously disposed wastes or property contamination, including contamination caused by prior owners or operators. Imposition of such liability schemes could have a material adverse impact on our operations and financial position.

In addition, our oil and gas development and production activities are subject to numerous federal, state and local laws and regulations relating to environmental quality and pollution control. These laws and regulations increase the costs of these activities and may prevent or delay the commencement or continuance of a given operation. Specifically, these activities are subject to laws and regulations regarding the acquisition of permits before drilling, restrictions on drilling activities in restricted areas, emissions into the environment, water discharges, and storage and disposition of wastes. In addition, legislation has been enacted that requires well and facility sites to be abandoned and reclaimed to the satisfaction of state authorities.

Further, we cannot ensure that such existing laws and regulations will not be revised or that new laws or regulations will not be adopted or become applicable to us. The clear trend in environmental regulation is to place more restrictions and limitations on activities that may be perceived to affect the environment, and thus there can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate. Revised or additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from our customers, could have a material adverse effect on our business, financial position, results of operations and prospects.

Climate change regulation at the federal, state or regional levels and/or new regulations issued by the Department of Homeland Security could result in increased operating and capital costs for us.

Studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases," may be contributing to warming of the Earth's atmosphere. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of natural gas, are examples of greenhouse gases. The U.S. Congress is actively considering legislation to reduce emissions of greenhouse gases. In addition, at least nine states in the Northeast and five states in the West have developed initiatives to regulate emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. The EPA is separately considering whether it will regulate greenhouse gases as "air pollutants" under the existing federal Clean Air Act. Passage of climate control legislation or other regulatory initiatives by Congress or various states of the U.S. or the adoption of regulations by the EPA or analogous state agencies that regulate or restrict emissions of greenhouse gases, including methane or carbon dioxide in areas in which we conduct business, could result in changes to the consumption and demand for natural gas and could have adverse effects on our business, financial position, results of operations and prospects.

Such changes could increase the costs of our operations, including costs to operate and maintain our facilities, install new emission controls on our facilities, acquire allowances to authorize our greenhouse gas emissions, pay any taxes related to our greenhouse gas emissions and administer and manage a greenhouse gas emissions program. While we may be able to include some or all of such increased costs in the rates charged by our pipeline, such recovery of costs is uncertain and may depend on events beyond our control including the outcome of future rate proceedings before the FERC and the provisions of any final legislation.

The Department of Homeland Security Appropriation Act of 2007 requires the Department of Homeland Security, referred to in this report as the DHS, to issue regulations establishing risk-based performance standards for the security of chemical and industrial facilities, including oil and gas facilities that are deemed to present "high levels of security risk." The DHS has issued rules that establish chemicals of interest and their respective threshold quantities that will trigger compliance with these standards. Covered facilities that are determined by the DHS to pose a high level of security risk will be required to prepare and submit Security Vulnerability Assessments and Site Security Plans as well as comply with other regulatory requirements, including those regarding inspections, audits, recordkeeping and protection of chemical-terrorism vulnerability information. We have not yet determined the extent to which our facilities are subject to coverage under the interim rules or the associated costs to comply, but it is possible that such costs could be substantial.

Our substantial debt could adversely affect our financial health and make us more vulnerable to adverse economic conditions.

As of September 30, 2008, we had outstanding $8,340.9 million of consolidated debt (excluding the value of interest rate swaps). This level of debt could have important consequences, such as:

- limiting our ability to obtain additional financing to fund our working capital, capital expenditures, debt service requirements or potential growth or for other purposes;
- limiting our ability to use operating cash flow in other areas of our business because we must dedicate a substantial portion of these funds to make payments on our debt;
- placing us at a competitive disadvantage compared to competitors with less debt; and
- increasing our vulnerability to adverse economic and industry conditions.

Each of these factors is to a large extent dependent on economic, financial, competitive and other factors beyond our control.

Our large amount of variable rate debt makes us vulnerable to increases in interest rates.

As of September 30, 2008, we had outstanding $8,340.9 million of consolidated debt (excluding the value of interest rate swaps). Of this amount, approximately 46.6% was subject to variable interest rates, either as short-term or long-term variable rate debt obligations or as long-term fixed-rate debt converted to variable rates through the use of interest rate swaps. Should interest rates increase significantly, the amount of cash required to service our debt would increase.

Terrorist attacks, or the threat of them, may adversely affect our business.

The U.S. government has issued public warnings that indicate that pipelines and other energy assets might be specific targets of terrorist organizations. These potential targets might include our pipeline systems or storage facilities. Our operations could become subject to increased governmental scrutiny that would require increased security measures. Recent federal legislation provides an insurance framework that should cause current insurers to continue to provide sabotage and terrorism coverage under standard property insurance policies. Nonetheless, there is no assurance that adequate sabotage and terrorism insurance will be available at rates we believe are reasonable in the near future. These developments may subject our operations to increased risks, as well as increased costs, and, depending on their ultimate magnitude, could have a material adverse effect on our business, results of operations and financial condition.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds.

Effective August 28, 2008, we issued 2,014,693 common units to Knight Inc. in connection with our acquisition of a 33 1/3% ownership interest in the Express pipeline system net assets and the Jet Fuel pipeline system net assets.

As agreed between Knight and us, the units were valued at $116.0 million. The units were issued to a single accredited investor in a transaction not involving a public offering and were therefore exempt from registration pursuant to Section 4(2) of the Securities Act of 1933.

Item 3. Defaults Upon Senior Securities.

None.

Item 4. Submission of Matters to a Vote of Security Holders.

None.

Item 5. Other Information.

Our management and the directors and management of our general partner and KMR are saddened by the passing of Mr. Edward O. Gaylord, who died on September 28, 2008 in Houston, Texas. He was 76 years old. In February 1997, following the change in control of our general partner, Mr. Gaylord was one of only two non-employees of our general partner elected to serve on its board of directors, and since that time, we and our general partner benefitted from his continuous advice and counsel. He was also elected as one of the founding directors of KMR upon its formation in February 2001, and at the time of his death, served as a member of each board’s Audit Committee, Compensation Committee, and Nominating and Governance Committee. Our Nominating and Governance Committee is in the process of identifying and meeting with potential replacements to fill the vacancy on KMR's Board of Directors. We hope to fill the vacancy by the end of the year.

Item 6. Exhibits.

*3.1 -- Third Amended and Restated Agreement of Limited Partnership of Kinder Morgan Energy Partners, L.P. (filed as Exhibit 3.1 to Kinder Morgan Energy Partners, L.P. Form 10-Q (File No. 1-11234) for the quarter ended June 30, 2001, filed on August 9, 2001).

*3.2 -- Amendment No. 1 dated November 19, 2004 to Third Amended and Restated Agreement of Limited Partnership of Kinder Morgan Energy Partners, L.P. (filed as Exhibit 99.1 to Kinder Morgan Energy Partners, L.P. Form 8-K, filed November 22, 2004).

*3.3 -- Amendment No. 2 to Third Amended and Restated Agreement of Limited Partnership of Kinder Morgan Energy Partners, L.P. (filed as Exhibit 99.1 to Kinder Morgan Energy Partners, L.P. Form 8-K, filed May 5, 2005).

*3.4 -- Amendment No. 3 to Third Amended and Restated Agreement of Limited Partnership of Kinder Morgan Energy Partners, L.P. (filed as Exhibit 3.1 to Kinder Morgan Energy Partners, L.P. Form 8-K, filed April 21, 2008).

*4.1 -- Certificate of the Vice President and Treasurer and the Vice President and Chief Financial Officer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 6.95% Senior Notes due 2038 (filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P. Form 10-Q for the quarter ended June 30, 2007 filed August 8, 2007).

*4.2 -- Certificate of the Vice President and Treasurer and the Vice President and Chief Financial Officer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 5.95% Senior Notes due 2018 (filed as Exhibit 4.28 to Kinder Morgan Energy Partners, L.P. Form 10-K for the year ended December 31, 2007 filed February 26, 2008).

4.3 -- Certain instruments with respect to long-term debt of Kinder Morgan Energy Partners, L.P. and its consolidated subsidiaries which relate to debt that does not exceed 10% of the total assets of Kinder Morgan Energy Partners, L.P. and its consolidated subsidiaries are omitted pursuant to Item 601(b) (4) (iii) (A) of Regulation S-K, 17 C.F.R. sec.229.601. Kinder Morgan Energy Partners, L.P. hereby agrees to furnish supplementally to the Securities and Exchange Commission a copy of each such instrument upon request.

*10. 1 -- First Amendment to Retention and Relocation Agreement, dated as of July 16, 2008, between Knight Inc. and Scott E. Parker (filed as Exhibit 10.1 to Kinder Morgan Energy Partners, L.P. Form 8-K, filed July 25, 2008).

11 -- Statement re: computation of per share earnings.

12 -- Statement re: computation of ratio of earnings to fixed charges.

*18 -- Letter re: change in accounting principle (filed as Exhibit 18 to Kinder Morgan Energy Partners, L.P. Form 10-Q for the quarter ended June 30, 2008 filed August 7, 2008).

31.1 -- Certification by CEO pursuant to Rule 13a-14 or 15d-14 of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.2 -- Certification by CFO pursuant to Rule 13a-14 or 15d-14 of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32.1 -- Certification by CEO pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

32.2 -- Certification by CFO pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

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* Asterisk indicates exhibits incorporated by reference as indicated; all other exhibits are filed herewith, except as noted otherwise.

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

KINDER MORGAN ENERGY PARTNERS, L.P.
Registrant (A Delaware limited partnership)

By: **KINDER MORGAN G.P., INC.,**
its sole General Partner

By: **KINDER MORGAN MANAGEMENT, LLC**,
the Delegate of Kinder Morgan G.P., Inc.

/s/ Kimberly A. Dang

Kimberly A. Dang
Vice President and Chief Financial Officer
(principal financial and accounting officer)
Date: November 5, 2008

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Section 2: EX-11 (EXHIBIT 11)

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES
EXHIBIT 11 — STATEMENT RE: COMPUTATION OF PER SHARE EARNINGS
(Units in millions; Dollars in millions except per unit amounts)

	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007
Weighted average number of limited partners' units on which limited partners' net income per unit is based:		
Basic	258.8	239.0
Add: Incremental units under contracts to issue units depending on the market price of the units at a future date	—	—
Assuming dilution	258.8	239.0
Calculation of Limited Partners' interest in Net Income:		
Income from Continuing Operations	$ 329.8	$ 205.2
Less: General Partner's interest in Income from Continuing Operations	(205.6)	(155.7)
Limited Partners' interest in Income from Continuing Operations	124.2	49.5
Add:Limited Partners' interest in Income from Discontinued Operations	—	8.5
Limited Partners' interest in Net Income	$ 124.2	$ 58.0
Basic and Diluted Limited Partners' Net Income per unit:		
Income from Continuing Operations	$ 0.48	$ 0.21
Income from Discontinued Operations	$ —	$ 0.03
Net Income	$ 0.48	$ 0.24

	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
Weighted average number of limited partners' units on which limited partners' net income per unit is based:		
Basic	255.5	235.0
Add: Incremental units under contracts to issue units depending on the market price of the units at a future date	—	0.1
Assuming dilution	255.5	235.1
Calculation of Limited Partners' interest in Net Income (Loss):		
Income from Continuing Operations	$ 1,037.4	$ 275.9
Less:General Partner's interest in Income from Continuing Operations	(588.9)	(439.9)
Limited Partners' interest in Income (Loss) from Continuing Operations	448.5	(164.0)
Add: Limited Partners' interest in Income from Discontinued Operations	1.3	20.9
Limited Partners' interest in Net Income (Loss)	$ 449.8	$ (143.1)
Basic and Diluted Limited Partners' Net Income (Loss) per unit:		
Income (Loss) from Continuing Operations	$ 1.76	$ (0.70)
Income from Discontinued Operations	$ —	$ 0.09
Net Income (Loss)	$ 1.76	$ (0.61)

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Section 3: EX-12 (EXHIBIT 12)

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES
EXHIBIT 12 — STATEMENT RE: COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES
(Dollars In Millions Except Ratio Amounts)

	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
Earnings:		
Pre-tax income from continuing operations before adjustment for minority interest and equity earnings (including amortization of excess cost of equity investments) per statements of income	$ 970.2	$ 269.6
Add:		
Fixed charges		
Services	343.5	328.8
Amortization of capitalized interest	2.0	1.0
Distributed income of equity investees	114.9	87.9
Less:		
Interest capitalized from continuing operations	(29.7)	(21.8)
Minority interest in pre-tax income of subsidiaries with no fixed charges	(0.2)	(0.4)
Income as adjusted	$ 1,400.7	$ 665.1
Fixed charges:		
Interest and debt expense, net per statements of income (includes amortization of debt discount, premium, and debt issuance costs; excludes capitalized interest)	$ 328.2	$ 316.2
Add:		
Portion of rents representative of the interest factor		
Services	15.3	12.6
Fixed charges	$ 343.5	$ 328.8

Ratio of earnings to fixed charges	4.08	2.02

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Section 4: EX-31 (EXHIBIT 31.1)

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES
EXHIBIT 31.1 – CERTIFICATION PURSUANT TO RULE 13A-14(A) OR 15D-14(A) OF THE SECURITIES EXCHANGE ACT OF 1934, AS ADOPTED PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Richard D. Kinder, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Kinder Morgan Energy Partners, L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 5, 2008

/s/ Richard D. Kinder

Richard D. Kinder
Chairman and Chief Executive Officer of Kinder Morgan Management, LLC, the delegate of Kinder Morgan G.P., Inc., the General Partner of Kinder Morgan Energy Partners, L.P.

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Section 5: EX-31 (EXHIBIT 31.2)

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES
EXHIBIT 31.2 – CERTIFICATION PURSUANT TO RULE 13A-14(A) OR 15D-14(A) OF THE SECURITIES EXCHANGE ACT OF 1934, AS ADOPTED PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Kimberly A. Dang, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Kinder Morgan Energy Partners, L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 5, 2008

/s/ Kimberly A. Dang

Kimberly A. Dang

Vice President and Chief Financial Officer of Kinder Morgan Management, LLC, the delegate of Kinder Morgan G.P., Inc., the General Partner of Kinder Morgan Energy Partners, L.P.

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Section 6: EX-32 (EXHIBIT 32.1)

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES
EXHIBIT 32.1 – CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350, AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of Kinder Morgan Energy Partners, L.P. (the "Company") on Form 10-Q for the quarterly period ending September 30, 2008, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), the undersigned, in the capacity and on the date indicated below, hereby certifies pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

A signed original of this written statement required by Section 906 has been provided to Kinder Morgan Energy Partners, L.P. and will be retained by Kinder Morgan Energy Partners, L.P. and furnished to the Securities and Exchange Commission or its staff upon request.

Dated: November 5, 2008

/s/ Richard D. Kinder

Richard D. Kinder
Chairman and Chief Executive Officer of Kinder Morgan Management, LLC, the delegate of Kinder Morgan G.P., Inc., the General Partner of Kinder Morgan Energy Partners, L.P.

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Section 7: EX-32 (EXHIBIT 32.2)

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES
EXHIBIT 32.2 – CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350, AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of Kinder Morgan Energy Partners, L.P. (the "Company") on Form 10-Q for the quarterly period ending September 30, 2008, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), the undersigned, in the capacity and on the date indicated below, hereby certifies pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange

Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

A signed original of this written statement required by Section 906 has been provided to Kinder Morgan Energy Partners, L.P. and will be retained by Kinder Morgan Energy Partners, L.P. and furnished to the Securities and Exchange Commission or its staff upon request.

Dated: November 5, 2008

/s/ Kimberly A. Dang

Kimberly A. Dang
Vice President and Chief Financial Officer of Kinder Morgan Management, LLC, the delegate of Kinder Morgan G.P., Inc., the General Partner of Kinder Morgan Energy Partners, L.P.

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KMP 10-K 12/31/2007

Section 1: 10-K (FORM 10-K)

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2007

Or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission file number: 1-11234

Kinder Morgan Energy Partners, L.P.
(Exact name of registrant as specified in its charter)

Delaware	**76-0380342**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*

500 Dallas, Suite 1000, Houston, Texas 77002
(Address of principal executive offices)(zip code)

Registrant's telephone number, including area code: 713-369-9000

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Units	New York Stock Exchange

Securities registered Pursuant to Section 12(g) of the Act:
None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act of 1933. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Securities Exchange Act of 1934. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company (as defined in Rule 12b-2 of the Securities Exchange Act of 1934).

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Securities Exchange Act of 1934). Yes ☐ No ☒

Aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant, based on closing prices in the daily composite list for transactions on the New York Stock Exchange on June 29, 2007 was approximately $8,185,538,074. As of January 31, 2008, the registrant had 170,224,734 Common Units outstanding.

KINDER MORGAN ENERGY PARTNERS, L.P.

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PART I

Items 1 and 2. *Business and Properties.*

In this report, unless the context requires otherwise, references to "we," "us," "our," "KMP" or the "Partnership" are intended to mean Kinder Morgan Energy Partners, L.P., a Delaware limited partnership formed in August 1992, our operating limited partnerships and their subsidiaries. Our common units, which represent limited partner interests in us, trade on the New York Stock Exchange under the symbol "KMP." The address of our principal executive offices is 500 Dallas, Suite 1000, Houston, Texas 77002, and our telephone number at this address is (713) 369-9000. You should read the following discussion and analysis in conjunction with our consolidated financial statements included elsewhere in this report. All dollars in this report are United States dollars, except where stated otherwise. Canadian dollars are designated as C$.

(a) General Development of Business

Organizational Structure

Kinder Morgan Energy Partners, L.P. is a leading pipeline transportation and energy storage company in North America. We own an interest in or operate more than 25,000 miles of pipelines and approximately 165 terminals. Our pipelines transport natural gas, gasoline, crude oil, carbon dioxide and other products, and our terminals store petroleum products and chemicals and handle bulk materials like coal and petroleum coke. We are also the leading provider of carbon dioxide, commonly called "CO_2," for enhanced oil recovery projects in North America. As one of the largest publicly traded pipeline limited partnerships in America, we have an enterprise value of approximately $20 billion.

Our general partner is Kinder Morgan G.P., Inc., a Delaware corporation. On July 27, 2007, our general partner issued and sold 100,000 shares of Series A fixed-to-floating rate term cumulative preferred stock due 2057. The consent of holders of a majority of these preferred shares is required with respect to a commencement of or a filing of a voluntary bankruptcy proceeding with respect to us, or two of our subsidiaries: SFPP, L.P. and Calnev Pipe Line LLC.

Knight Inc., a Kansas corporation and a private company formerly known as Kinder Morgan, Inc., indirectly is the sole owner of the common stock of our general partner. On August 28, 2006, Kinder Morgan, Inc., a Kansas corporation referred to as "KMI" in this report, entered into an agreement and plan of merger whereby generally each share of KMI common stock would be converted into the right to receive $107.50 in cash without interest. KMI in turn would merge with a wholly owned subsidiary of Knight Holdco LLC, a privately owned company in which Richard D. Kinder, Chairman and Chief Executive Officer of KMI, would be a major investor. On May 30, 2007, the merger closed, with KMI continuing as the surviving legal entity and subsequently renamed "Knight Inc.," referred to as "Knight" in this report. Additional investors in Knight Holdco LLC include the following: other senior members of Knight management, most of whom are also senior officers of Kinder Morgan G.P., Inc. (our general partner) and of Kinder Morgan Management, LLC (our general partner's delegate); KMI co-founder William V. Morgan; KMI board members Fayez Sarofim and Michael C. Morgan; and affiliates of (i) Goldman Sachs Capital Partners; (ii) American International Group, Inc.; (iii) The Carlyle Group; and (iv) Riverstone Holdings LLC. This transaction is referred to in this report as the "going-private transaction."

As of December 31, 2007, Knight and its consolidated subsidiaries owned, through its general and limited partner interests, an approximately 13.9% interest in us. In addition to the distributions it receives from its limited and general partner interests, Knight also receives an incentive distribution from us as a result of its ownership of our general partner. This incentive distribution is calculated in increments based on the amount by which quarterly distributions to our unitholders exceed specified target levels as set forth in our partnership agreement, reaching a maximum of 50% of distributions allocated to the general partner for distributions above $0.23375 per limited partner unit per quarter. Including both its general and limited partner interests in us, at the 2007 distribution level, Knight received approximately 49% of all quarterly "Available Cash" distributions (as defined in our partnership agreement) from us, with approximately 43% and 6% of all quarterly distributions from us attributable to Knight's general partner and limited partner interests, respectively. The actual level of distributions Knight will receive in the future will vary with the level of distributions to our limited partners determined in accordance with our partnership agreement.

Kinder Morgan Management, LLC, referred to as "KMR" in this report, is a Delaware limited liability company formed in February 2001. Our general partner owns all of KMR's voting securities and, pursuant to a delegation of control agreement, our general partner has delegated to KMR, to the fullest extent permitted under Delaware law and our partnership agreement, all of its power and authority to manage and control our business and affairs, except that KMR cannot take certain specified actions without the approval of our general partner. Under the delegation of control agreement, KMR, as the delegate of our general partner, manages and controls our business and affairs and the business and affairs of our operating limited partnerships and their subsidiaries. Furthermore, in accordance with its limited liability company agreement, KMR's activities are limited to being a limited partner in, and managing and controlling the business and affairs of us, our operating limited partnerships and their subsidiaries.

KMR's shares represent limited liability company interests and trade on the New York Stock Exchange under the symbol "KMR." Since its inception, KMR has used substantially all of the net proceeds received from the public offerings of its shares to purchase i-units from us. The i-units are a separate class of limited partner interests in us and are issued only to KMR. Under the terms of our partnership agreement, the holders of our i-units are entitled to vote on all matters on which the holders of our common units are entitled to vote.

In general, our limited partner units, consisting of i-units, common units and Class B units (the Class B units are similar to our common units except that they are not eligible for trading on the New York Stock Exchange), will vote together as a single class, with each i-unit, common unit and Class B unit having one vote. We pay our quarterly distributions from operations and interim capital transactions to our common and Class B unitholders in cash, and we pay our quarterly distributions to KMR in additional i-units rather than in cash. As of December 31, 2007, KMR, through its ownership of our i-units, owned approximately 29.2% of all of our outstanding limited partner units.

Recent Developments

The following is a brief listing of significant developments since December 31, 2006. Additional information regarding most of these items may be found elsewhere in this report.

- Effective January 1, 2007, we acquired the remaining approximate 50.2% interest in the Cochin pipeline system that we did not already own from affiliates of BP for an aggregate consideration of approximately $47.8 million, consisting of $5.5 million in cash and a note payable having a fair value of $42.3 million. As part of the transaction, the seller also agreed to reimburse us for certain pipeline integrity management costs over a five-year period in an aggregate amount not to exceed $50 million. Upon closing, we became the operator of the pipeline;

- On January 17, 2007, we announced that our CO_2 business segment will invest approximately $120 million to further expand its operations and enable it to meet the increased demand for carbon dioxide in the Permian Basin. The expansion activities will take place in southwest Colorado and include developing a new carbon dioxide source field (named the Doe Canyon Deep Unit that went in service during the first quarter of 2008) and adding infrastructure at both the McElmo Dome Unit and the Cortez Pipeline. The entire expansion is expected to be completed by the middle of 2008;

- On January 30, 2007, we completed a public offering of senior notes. We issued a total of $1.0 billion in principal amount of senior notes, consisting of $600 million of 6.00% notes due February 1, 2017, and $400 million of 6.50% notes due February 1, 2037. We received proceeds from the issuance of the notes, after underwriting discounts and commissions, of $992.8 million, and we used the proceeds to reduce the borrowings under our commercial paper program;

- On February 14, 2007, the first phase of the Rockies Express pipeline system, the 327-mile REX-Entrega Project, was placed in service at a cost of approximately $745 million and provided up to 500 million cubic feet of natural gas capacity from the Meeker Hub in Rio Blanco County, Colorado and Wamsutter Hub in Sweetwater County, Wyoming to the Cheyenne Hub in Weld County, Colorado.

  The Rockies Express pipeline project is an approximate $4.9 billion, 1,679-mile natural gas pipeline system which is owned and currently being developed by Rockies Express Pipeline LLC. The Rockies Express pipeline project is to be completed in three phases: (i) a 327-mile, $745 million pipeline running from the Meeker Hub to the Cheyenne Hub with a nominal capacity of 500 million cubic feet per day; (ii) a 713-mile, $1.6 billion pipeline from the Cheyenne Hub to an interconnect in Audrain County, Missouri, transporting up to 1.5 billion cubic feet per day; and (iii) a 639-mile, $2.6 billion pipeline from Audrain County, Missouri to Clarington, located in Monroe County, Ohio. When fully completed, the Rockies Express pipeline system will have the capability to transport 1.8 billion cubic feet per day of natural gas, and binding firm commitments have been secured for all of the pipeline capacity. On January 12, 2008, interim service on the REX-West Project (second phase) commenced. Full service on the REX-West system for 1.5 billion cubic feet per day of contracted capacity is expected to commence in mid-March 2008. See "—(c) Narrative Description of Business—Business Segments—Natural Gas Pipelines—Rockies Express Pipeline" for more information;

- On February 28, 2007, we announced plans to invest up to $100 million to expand our liquids terminal facilities in order to help serve the growing biodiesel market. We entered into long-term agreements as lessors with Green Earth Fuels, LLC to build tankage that will handle biodiesel at our Houston Ship Channel liquids facility. Green Earth Fuels completed construction of an 86 million gallon biodiesel production facility at our Galena Park, Texas liquids terminal in the fourth quarter of 2007;

- On April 30, 2007, we acquired the Trans Mountain pipeline system from Knight for $549.1 million. The Trans Mountain pipeline system, which transports crude oil and refined products from Edmonton, Alberta, Canada to marketing terminals and refineries in British Columbia and the state of Washington, currently transports approximately 260,000 barrels per day. An additional expansion that will increase capacity of the pipeline to 300,000 barrels per day is expected to be in service by November 2008. Current accounting principles require our consolidated financial statements and all other financial information included in this report to be stated to assume that the transfer of Trans Mountain net assets from Knight to us had occurred at the date when both Trans Mountain and we met the accounting requirements for entities under common control (January 1, 2006). As a result, financial statements and financial information presented for prior periods in this report have been restated to reflect our acquisition. In addition, due to the fact that Trans Mountain's operations are managed separately, involve different products and marketing strategies, and produce discrete financial information that is separately evaluated internally by our management, we have identified our Trans Mountain pipeline system as a separate reportable business segment. For additional information regarding this acquisition, see Note 3 to our consolidated financial statements;

- On May 14, 2007, we announced plans to construct a $72 million natural gas pipeline designed to bring new supplies out of East Texas to markets in the Houston and Beaumont, Texas areas. The new pipeline will consist of approximately 63 miles of 24-inch diameter pipe and multiple interconnections with other pipelines. It will connect our Kinder Morgan Tejas system in Harris County, Texas to our Kinder Morgan Texas Pipeline system in Polk County near Goodrich, Texas. In addition, we entered into a long-term binding agreement with CenterPoint Energy Services, Inc. to provide firm transportation for a significant portion of the initial project capacity, which will consist of approximately 225 million cubic feet per day of natural gas using existing compression and be expandable to over 400 million cubic feet per day with additional compression;

- On May 17, 2007, KMR closed the public offering of 5,700,000 of its shares at a price of $52.26 per share. The net proceeds from the offering were used by KMR to buy additional i-units from us. We used the proceeds of $297.9 million from our i-unit issuance to reduce the borrowings under our commercial paper program;

- On May 30, 2007, we purchased the Vancouver Wharves bulk marine terminal from British Columbia Railway Company, a crown corporation owned by the Province of British Columbia, for an aggregate consideration of $57.2 million, consisting of $38.8 million in cash and $18.4 million in assumed liabilities. The Vancouver Wharves facility is located on the north shore of the Port of Vancouver's main harbor, and includes five deep-sea vessel berths situated on a 139-acre site. The terminal assets include significant rail infrastructure, dry bulk and liquid storage, and material handling systems which allow the terminal to handle over 3.5 million tons of cargo annually;

- On June 21, 2007, we closed a public offering of $550 million in principal amount of 6.95% senior notes. The notes are due January 15, 2038. We received proceeds from the issuance of the notes, after underwriting discounts and commissions, of $543.9 million, and we used the proceeds to reduce our commercial paper debt;

- On June 22, 2007, the Federal Energy Regulatory Commission, referred to in this report as the FERC, issued an order granting construction and operation of our Kinder Morgan Louisiana Pipeline project, and we officially accepted the order on July 10, 2007. The Kinder Morgan Louisiana Pipeline is expected to cost approximately $510 million and will provide approximately 3.2 billion cubic feet per day of take-away natural gas capacity from the Cheniere Sabine Pass liquefied natural gas terminal, located in Cameron Parish, Louisiana, to various delivery points in Louisiana and will provide interconnects with many other natural gas pipelines, including Natural Gas Pipeline Company of America. The project is supported by fully subscribed capacity and long-term customer commitments with Chevron and Total and is expected to be in service by January 1, 2009;

- On July 10, 2007, we announced a combined $41 million investment for two terminal expansions to help meet the growing need for terminal services in key markets along the Gulf Coast. The investment consists of (i) the construction of a terminal that will include liquids storage, transfer and packaging facilities at the Rubicon Plant site in Geismar, Louisiana; and (ii) the purchase of liquids storage tanks from Royal Vopak in Westwego, Louisiana. The tanks have a storage capacity of approximately 750,000 barrels for vegetable oil, biodiesel, ethanol and other liquids products. The new terminal being built in Geismar will be capable of handling inbound and outbound material via pipeline, rail, truck and barge/vessel. Construction is expected to be complete by the fourth quarter of 2008;

- On July 23, 2007, following the FERC’s expedited approval of our CALNEV Pipeline’s proposed tariff rate structure, we announced our continuing development of the approximate $426 million expansion of the pipeline system into Las Vegas, Nevada. The expansion involves the construction of a new 16-inch diameter pipeline, which will parallel existing utility corridors between Colton, California and Las Vegas in order to minimize environmental impacts. System capacity would increase to approximately 200,000 barrels per day upon completion of the expansion, and could be increased as necessary to over 300,000 barrels per day with the addition of pump stations. The CALNEV expansion is expected to be complete in early 2011;

- On August 6, 2007, Kinder Morgan Interstate Gas Transmission LLC, referred to in this report as KMIGT, filed for regulatory approval to construct and operate a 41-mile, $29 million natural gas pipeline from the Cheyenne Hub to markets in and around Greeley, Colorado. When completed, the Colorado Lateral expansion project will provide firm transportation of up to 55 million cubic feet per day to a local utility under long-term contract. On February 21, 2008, the FERC granted the certification application;

- On August 23, 2007, we announced that we have begun construction on the approximately C$467 million Anchor Loop project, the second phase of the Trans Mountain pipeline system expansion that will increase pipeline capacity from approximately 260,000 to 300,000 barrels of crude oil per day. The project is expected to be complete in November 2008. In April 2007, we commissioned 10 new pump stations which boosted capacity on Trans Mountain from 225,000 to approximately 260,000 barrels per day. The pipeline is currently operating at full capacity;

- On August 28, 2007, we closed a public offering of $500 million in principal amount of 5.85% senior notes. The notes are due September 15, 2012. We received proceeds from the issuance of the notes, after underwriting discounts and commissions, of $497.8 million, and we used the proceeds to reduce our commercial paper debt;

- Effective September 1, 2007, we acquired five bulk terminal facilities from Marine Terminals, Inc. for an aggregate consideration of approximately $101.5 million, consisting of $100.3 million in cash and an assumed liability of $1.2 million. The acquired assets and operations are primarily involved in the handling and storage of steel and alloys, and also provide stevedoring and harbor services, scrap handling, and scrap processing services to customers in the steel and alloys industry. The operations are located in Blytheville, Arkansas; Decatur, Alabama; Hertford, North Carolina; and Berkley, South Carolina. Combined, the five facilities handled approximately 13.7 million tons of steel products in 2007. Under long-term contracts, the acquired terminal facilities will continue to provide handling, processing, harboring and warehousing services to Nucor Corporation, one of the nation's largest steel and steel products companies;

- Effective October 5, 2007, we sold our North System natural gas liquids and refined petroleum products pipeline system and our 50% ownership interest in the Heartland Pipeline Company to ONEOK Partners, L.P. for approximately $298.6 million in cash. Our investment in net assets, including all transaction related accruals, was approximately $145.8 million, most of which represented property, plant and equipment, and we recognized approximately $152.8 million of gain on the sale of these net assets. In accordance with generally accepted accounting principles, we accounted for the North System business as a discontinued operation for all periods presented in this report, and we reported the gain with the caption as "Gain on disposal of North System" on our accompanying consolidated statement of income;

- On October 9, 2007, Midcontinent Express Pipeline LLC filed an application with the FERC requesting a certificate of public convenience and necessity that would authorize construction and operation of the approximate 500-mile Midcontinent Express Pipeline natural gas transmission system. We own a 50% interest in Midcontinent Express Pipeline LLC and Energy Transfer Partners L.P. owns the remaining interest. The Midcontinent Express Pipeline will create long-haul, firm natural gas transportation takeaway capacity, either directly or indirectly, from natural gas producing regions located in Texas, Oklahoma and Arkansas. The total project is expected to cost approximately $1.3 billion, and will have an initial transportation capacity of approximately 1.4 billion cubic feet per day of natural gas.

  The Midcontinent Express Pipeline will originate near Bennington, Oklahoma and terminate at an interconnect with Williams' Transco natural gas pipeline system near Butler, Alabama. It will also connect to Natural Gas Pipeline Company of America's natural gas pipeline and to Energy Transfer Partners' 135-mile natural gas pipeline, which extends from the Barnett Shale natural gas producing area in North Texas to an interconnect with the Texoma Pipeline near Paris, Texas. The Midcontinent Express Pipeline now has long-term binding commitments from multiple shippers for approximately 1.2 billion cubic feet per day and, in order to provide a seamless transportation path from various locations in Oklahoma, the pipeline has also executed a firm capacity lease agreement with Enogex, Inc., an Oklahoma-based intrastate natural gas gathering and pipeline company that is wholly-owned by OGE Energy Corp. Subject to the receipt of regulatory approvals, construction of the pipeline is expected to commence in August 2008 and be in service during the first quarter of 2009.

  In January 2008, in conjunction with the signing of additional binding transportation commitments, Midcontinent Express and MarkWest entered into an option agreement which provides MarkWest a one-time right to purchase a 10% ownership interest in Midcontinent Express after the pipeline is fully constructed and placed into service. If the option is exercised, we and Energy Transfer Partners will each own 45% of Midcontinent Express, while MarkWest will own the remaining 10%;

- On October 17, 2007, we announced that we will invest approximately $23 million to expand our Kinder Morgan Interstate Gas Transmission pipeline system in order to serve five separate industrial plants (four of which produce ethanol) near Grand Island, Nebraska. The project is fully subscribed with long-term customer contracts, and subject to the receipt of regulatory approvals filed December 21, 2007, the expansion project is expected to be fully operational by the fall of 2008. Since 2000, our KMIGT system has connected to 17 new ethanol plants, 11 of which are located in the state of Nebraska;

- On November 26, 2007, we announced that we expect to declare cash distributions of $4.02 per unit for 2008, an almost 16% increase over our cash distributions of $3.48 per unit for 2007. This expectation includes contributions from assets owned by us as of the announcement date and does not include any potential benefits from unidentified acquisitions. Additionally, our expectation does not take into account any capital costs associated with financing the payment of reparations sought by shippers on our Pacific operations' interstate pipelines. Our expected growth in distributions in 2008 will be fueled by incremental earnings from Rockies Express-West (the western portion of the Rockies Express Pipeline), higher hedge prices on our

crude oil production (budgeted production volumes for the SACROC oil field unit in 2008 are approximately equal to the volumes realized in 2007), and an anticipated strong performance from our remaining business portfolio;

- In December 2007, we completed a public offering of 7,130,000 of our common units, including common units sold pursuant to the underwriters' over-allotment option, at a price of $48.09 per unit, less commissions and underwriting expenses. We received net proceeds of $342.9 million for the issuance of these 7,130,000 common units, and we used the proceeds to reduce the borrowings under our commercial paper program;
- In December 2007, we completed a second expansion of our Pacific operations' East Line pipeline segment. This expansion consisted of replacing approximately 130 miles of 12-inch diameter pipe between El Paso, Texas and Tucson, Arizona with new 16-inch diameter pipe, constructing additional pump stations, and adding new storage tanks at Tucson. The project, completed at a cost of approximately $154 million, will increase East Line capacity by 36% (to approximately 200,000 barrels per day) to meet the demand for refined petroleum products, and will provide the platform for further incremental expansions through horsepower additions to the system;
- On December 31, 2007, TransColorado Gas Transmission LLC completed an approximate $50 million expansion to provide up to 250 million cubic feet per day of natural gas transportation, starting January 1, 2008, from the Blanco Hub to an interconnect with the Rockies Express pipeline system at the Meeker Hub;
- During 2007, we spent $1,691.6 million for additions to our property, plant and equipment, including both expansion and maintenance projects. Our capital expenditures included the following:

    - $480.0 million in our Terminals segment, largely related to expanding the petroleum products storage capacity at our liquids terminal facilities, including the construction of additional liquids storage tanks at our facilities in Canada and at our facilities located on the Houston Ship Channel and the New York Harbor, and to various expansion projects and improvements undertaken at multiple terminal facilities;
    - $382.5 million in our CO_2 segment, mostly related to additional infrastructure, including wells and injection and compression facilities, to support the expanding carbon dioxide flooding operations at the SACROC and Yates oil field units in West Texas and to expand our capacity to produce and deliver CO_2 from our McElmo Dome and Doe Canyon Source Fields;
    - $305.7 million in our Trans Mountain segment, mostly related to pipeline expansion and improvement projects undertaken to increase crude oil and refined products delivery volumes;
    - $264.0 million in our Natural Gas Pipelines segment, mostly related to current construction of our Kinder Morgan Louisiana Pipeline and to various expansion and improvement projects on our Texas intrastate natural gas pipeline systems, including the development of additional natural gas storage capacity at our natural gas storage facilities located at Markham and Dayton, Texas; and
    - $259.4 million in our Products Pipelines segment, mostly related to the continued expansion work on our Pacific operations' East Line products pipeline, completion of construction projects resulting in additional capacity, and an additional refined products line on our CALNEV Pipeline in order to increase delivery service to the growing Las Vegas, Nevada market;

    Our capital expansion program in 2007 was approximately $2.6 billion (including our share of capital expenditures for both the Rockies Express and Midcontinent Express natural gas pipeline projects). Including all of our business acquisition expenditures, total spending was $3.3 billion. Our capital expansion program will continue to be significant in 2008, as we expect to invest approximately $3.3 billion in expansion capital expenditures (including our share of capital expenditures for both the Rockies Express and Midcontinent Express natural gas pipeline projects), which will help drive earnings and cash flow growth in 2009 and beyond;

- On January 16, 2008, we announced that we plan to invest approximately $56 million to construct a petroleum coke terminal at the BP refinery located in Whiting, Indiana. We have entered into a long-term contract to build and operate the facility, which will handle approximately 2.2 million tons of petroleum coke per year from a coker unit BP plans to construct to process heavy crude oil from Canada. The facility is expected to be in service in mid-year 2011;
- On February 12, 2008, we completed an additional public offering of senior notes. We issued a total of $900 million in principal amount of senior notes, consisting of $600 million of 5.95% notes due February 15, 2018, and $300 million of 6.95% notes due January 15, 2038. We received proceeds from the issuance of the notes, after underwriting discounts and commissions, of approximately $894.1 million, and we used the proceeds to reduce the borrowings under our commercial paper program; and
- On February 12, 2008, we completed an additional offering of 1,080,000 of our common units at a price of $55.65 per unit in a privately negotiated transaction. We received net proceeds of $60.1 million for the issuance of these 1,080,000 common units, and we used the proceeds to reduce the borrowings under our commercial paper program.

(b) Financial Information about Segments

For financial information on our five reportable business segments, see Note 15 to our consolidated financial statements.

(c) Narrative Description of Business

Business Strategy

The objective of our business strategy is to grow our portfolio of businesses by:

- focusing on stable, fee-based energy transportation and storage assets that are core to the energy infrastructure of growing markets within North America;
- increasing utilization of our existing assets while controlling costs, operating safely, and employing environmentally sound operating practices;
- leveraging economies of scale from incremental acquisitions and expansions of assets that fit within our strategy and are accretive to cash flow and earnings; and
- maximizing the benefits of our financial structure to create and return value to our unitholders.

Business Segments

We own and manage a diversified portfolio of energy transportation and storage assets. Our operations are conducted through our five operating limited partnerships and their subsidiaries and are grouped into five reportable business segments. These segments are as follows:

- Products Pipelines—which consists of approximately 8,300 miles of refined petroleum products pipelines that deliver gasoline, diesel fuel, jet fuel and natural gas liquids to various markets; plus approximately 60 associated product terminals and petroleum pipeline transmix processing facilities serving customers across the United States;
- Natural Gas Pipelines—which consists of approximately 14,700 miles of natural gas transmission pipelines and gathering lines, plus natural gas storage, treating and processing facilities, through which natural gas is gathered, transported, stored, treated, processed and sold;

- CO_2— which produces, markets and transports, through approximately 1,300 miles of pipelines, carbon dioxide to oil fields that use carbon dioxide to increase production of oil; owns interests in and/or operates ten oil fields in West Texas; and owns and operates a 450 mile crude oil pipeline system in West Texas;

- Terminals—which consists of approximately 108 owned or operated liquids and bulk terminal facilities and more than 45 rail transloading and materials handling facilities located throughout the United States and portions of Canada, which together transload, store and deliver a wide variety of bulk, petroleum, petrochemical and other liquids products for customers across the United States and Canada; and

- Trans Mountain—which consists of over 700 miles of common carrier pipelines, originating at Edmonton, Alberta, for the transportation of crude oil and refined petroleum to the interior of British Columbia and to marketing terminals and refineries located in the greater Vancouver, British Columbia area and Puget Sound in Washington State; plus five associated product terminals.

Generally, as utilization of our pipelines and terminals increases, our fee-based revenues increase. We do not face significant risks relating directly to short-term movements in commodity prices for two principal reasons. First, we primarily transport and/or handle products for a fee and are not engaged in significant unmatched purchases and resales of commodity products. Second, in those areas of our business where we do face exposure to fluctuations in commodity prices, primarily oil production in our CO_2 business segment, we engage in a hedging program to mitigate this exposure.

We regularly consider and enter into discussions regarding potential acquisitions, including those from Knight or its affiliates, and are currently contemplating potential acquisitions. Any such transaction would be subject to negotiation of mutually agreeable terms and conditions, receipt of fairness opinions and approval of the parties' respective boards of directors. While there are currently no unannounced purchase agreements for the acquisition of any material business or assets, such transactions can be effected quickly, may occur at any time and may be significant in size relative to our existing assets or operations.

It is our intention to carry out the above business strategy, modified as necessary to reflect changing economic conditions and other circumstances. However, as discussed under Item 1A "Risk Factors" below, there are factors that could affect our ability to carry out our strategy or affect its level of success even if carried out.

Products Pipelines

Our Products Pipelines segment consists of our refined petroleum products and natural gas liquids pipelines and their associated terminals, our Southeast terminals and our transmix processing facilities.

Pacific Operations

Our Pacific operations include our SFPP, L.P. operations, our CALNEV Pipeline operations and our West Coast Liquid Terminals operations. The assets include interstate common carrier pipelines regulated by the FERC, intrastate pipelines in the state of California regulated by the California Public Utilities Commission, and certain non rate-regulated operations and terminal facilities.

Our Pacific operations serve seven western states with approximately 3,000 miles of refined petroleum products pipelines and related terminal facilities that provide refined products to some of the fastest growing population centers in the United States, including California; Las Vegas and Reno, Nevada; and the Phoenix-Tucson, Arizona corridor. For 2007, the three main product types transported were gasoline (59%), diesel fuel (23%) and jet fuel (18%).

Our Pacific operations also includes CALNEV Pipeline which consists of two parallel 248-mile, 14-inch and 8-inch diameter pipelines that run from our facilities at Colton, California to Las Vegas, Nevada, and which also serves Nellis Air Force Base located in Las Vegas. It also includes approximately 55 miles of pipeline serving Edwards Air Force Base.

Our Pacific operations include 15 truck-loading terminals (13 on SFPP, L.P. and two on CALNEV) with an aggregate usable tankage capacity of approximately 13.7 million barrels. The truck terminals provide services including short-term product storage, truck loading, vapor handling, additive injection, dye injection and oxygenate blending.

Our Pacific operation's West Coast Liquid Terminals are fee-based terminals located in the Seattle, Portland, San Francisco and Los Angeles areas along the west coast of the United States with a combined total capacity of approximately 8.3 million barrels of storage for both petroleum products and chemicals.

Markets. Combined, our Pacific operations' pipelines transport approximately 1.3 million barrels per day of refined petroleum products, providing pipeline service to approximately 31 customer-owned terminals, 11 commercial airports and 14 military bases. Currently, our Pacific operations' pipelines serve approximately 100 shippers in the refined petroleum products market; the largest customers being major petroleum companies, independent refiners, and the United States military.

A substantial portion of the product volume transported is gasoline. Demand for gasoline depends on such factors as prevailing economic conditions, vehicular use patterns and demographic changes in the markets served. If current trends continue, we expect the majority of our Pacific operations' markets to maintain growth rates that will exceed the national average for the foreseeable future. The volume of products transported is affected by various factors, principally demographic growth, economic conditions, product pricing, vehicle miles traveled, population and fleet mileage. Certain product volumes can experience seasonal variations and, consequently, overall volumes may be lower during the first and fourth quarters of each year.

Supply. The majority of refined products supplied to our Pacific operations' pipeline system come from the major refining centers around Los Angeles, San Francisco, El Paso and Puget Sound, as well as from waterborne terminals and connecting pipelines located near these refining centers.

Competition. The two most significant competitors of our Pacific operations' pipeline system are proprietary pipelines owned and operated by major oil companies in the area where our pipeline system delivers products and also refineries with terminals that have trucking arrangements within our market areas. We believe that high capital costs, tariff regulation, and environmental and right-of-way permitting considerations make it unlikely that a competing pipeline system comparable in size and scope to our Pacific operations will be built in the foreseeable future. However, the possibility of individual pipelines being constructed or expanded to serve specific markets is a continuing competitive factor.

The use of trucks for product distribution from either shipper-owned proprietary terminals or from their refining centers continues to compete for short haul movements by pipeline. Our Pacific terminal operations compete with terminals owned by our shippers and by third party terminal operators in California, Arizona and Nevada. Competitors include Shell Oil Products U.S., BP (formerly Arco Terminal Services Company), Wilmington Liquid Bulk Terminals (Vopak), NuStar, and Chevron. We cannot predict with any certainty whether the use of short haul trucking will decrease or increase in the future.

Plantation Pipe Line Company

We own approximately 51% of Plantation Pipe Line Company, referred to in this report as Plantation, a 3,100-mile refined petroleum products pipeline system serving the southeastern United States. An affiliate of ExxonMobil owns the remaining 49% ownership interest. ExxonMobil is the largest shipper on the Plantation system both in terms of volumes and revenues. We operate the system pursuant to agreements with Plantation Services LLC and Plantation. Plantation serves as a common carrier of refined petroleum products to various metropolitan areas, including Birmingham, Alabama; Atlanta, Georgia; Charlotte, North Carolina; and the Washington, D.C. area.

For the year 2007, Plantation delivered an average of 535,672 barrels per day of refined petroleum products. These delivered volumes were comprised of gasoline (63%), diesel/heating oil (23%) and jet fuel (14%). Average delivery volumes for 2007 were 3.5% lower than the 555,063 barrels per day delivered during 2006. The decrease was predominantly driven by (i) the full year impact of alternative pipeline service (initial startup mid-2006) into Southeast markets, and (ii) changes in production patterns from Louisiana refineries related to refiners directing higher margin products (such as reformulated gasoline blendstock for oxygenate blending) into markets not directly served by Plantation.

Markets. Plantation ships products for approximately 30 companies to terminals throughout the southeastern United States. Plantation's principal customers are Gulf Coast refining and marketing companies, fuel wholesalers, and the United States Department of Defense. Plantation's top five shippers represent approximately 80% of total system volumes.

The eight states in which Plantation operates represent a collective pipeline demand of approximately two million barrels per day of refined petroleum products. Plantation currently has direct access to about 1.5 million barrels per day of this overall market. The remaining 0.5 million barrels per day of demand lies in markets (e.g., Nashville, Tennessee; North Augusta, South Carolina; Bainbridge, Georgia; and Selma, North Carolina) currently served by another pipeline company. Plantation also delivers jet fuel to the Atlanta, Georgia; Charlotte, North Carolina; and Washington, D.C. airports (Ronald Reagan National and Dulles). Combined jet fuel shipments to these four major airports increased 3% in 2007 compared to 2006, with the majority of this growth occurring at Dulles Airport.

Supply. Products shipped on Plantation originate at various Gulf Coast refineries from which major integrated oil companies and independent refineries and wholesalers ship refined petroleum products. Plantation is directly connected to and supplied by a total of ten major refineries representing approximately 2.3 million barrels per day of refining capacity.

Competition. Plantation competes primarily with the Colonial pipeline system, which also runs from Gulf Coast refineries throughout the southeastern United States and extends into the northeastern states.

Central Florida Pipeline

Our Central Florida pipeline system consists of a 110-mile, 16-inch diameter pipeline that transports gasoline and an 85-mile, 10-inch diameter pipeline that transports diesel fuel and jet fuel from Tampa to Orlando, with an intermediate delivery point on the 10-inch pipeline at Intercession City, Florida. In addition to being connected to our Tampa terminal, the pipeline system is connected to terminals owned and operated by TransMontaigne, Citgo, BP, and Marathon Petroleum. The 10-inch diameter pipeline is connected to our Taft, Florida terminal (located near Orlando) and is also the sole pipeline supplying jet fuel to the Orlando International Airport in Orlando, Florida. In 2007, the pipeline system transported approximately 113,800 barrels per day of refined products, with the product mix being approximately 69% gasoline, 12% diesel fuel, and 19% jet fuel.

We also own and operate liquids terminals in Tampa and Taft, Florida. The Tampa terminal contains approximately 1.5 million barrels of storage capacity and is connected to two ship dock facilities in the Port of Tampa. The Tampa terminal provides storage for gasoline, diesel fuel and jet fuel for further movement into either trucks or into the Central Florida pipeline system. The Tampa terminal also provides storage and truck rack blending services for ethanol and bio-diesel. The Taft terminal contains approximately 0.7 million barrels of storage capacity, for gasoline and diesel fuel for further movement into trucks.

Markets. The estimated total refined petroleum products demand in the state of Florida is approximately 800,000 barrels per day. Gasoline is, by far, the largest component of that demand at approximately 545,000 barrels per day. The total refined petroleum products demand for the Central Florida region of the state, which includes the Tampa and Orlando markets, is estimated to be approximately 360,000 barrels per day, or 45% of the consumption of refined products in the state. We distribute approximately 150,000 barrels of refined petroleum products per day, including the Tampa terminal truck loadings. The balance of the market is supplied primarily by trucking firms and marine transportation firms. Most of the jet fuel used at Orlando International Airport is moved through our Tampa terminal and the Central Florida pipeline system. The market in Central Florida is seasonal, with demand peaks in March and April during spring break and again in the summer vacation season, and is also heavily influenced by tourism, with Disney World and other attractions located near Orlando.

Supply. The vast majority of refined petroleum products consumed in Florida is supplied via marine vessels from major refining centers in the Gulf Coast of Louisiana and Mississippi and refineries in the Caribbean basin. A lesser amount of refined petroleum products is being supplied by refineries in Alabama and by Texas Gulf Coast refineries via marine vessels and through pipeline networks that extend to Bainbridge, Georgia. The supply into Florida is generally transported by ocean-going vessels to the larger metropolitan ports, such as Tampa, Port Everglades near Miami, and Jacksonville. Individual markets are then supplied from terminals at these ports and other smaller ports, predominately by trucks, except the Central Florida region, which is served by a combination of trucks and pipelines.

Competition. With respect to the Central Florida pipeline system, the most significant competitors are trucking firms and marine transportation firms. Trucking transportation is more competitive in serving markets close to the marine terminals on the east and west coasts of Florida. We are utilizing tariff incentives to attract volumes to the pipeline that might otherwise enter the Orlando market area by truck from Tampa or by marine vessel into Cape Canaveral. We believe it is unlikely that a new pipeline system comparable in size and scope to our Central Florida Pipeline system will be constructed, due to the high cost of pipeline construction, tariff regulation and environmental and right-of-way permitting in Florida. However, the possibility of such a pipeline or a smaller capacity pipeline being built is a continuing competitive factor.

With respect to the terminal operations at Tampa, the most significant competitors are proprietary terminals owned and operated by major oil companies, such as Marathon Petroleum, BP and Citgo, located along the Port of Tampa, and the Chevron and Motiva terminals in Port Tampa. These terminals generally support the storage requirements of their parent or affiliated companies' refining and marketing operations and provide a mechanism for an oil company to enter into exchange contracts with third parties to serve its storage needs in markets where the oil company may not have terminal assets.

Federal regulation of marine vessels, including the requirement under the Jones Act that United States-flagged vessels contain double-hulls, is a significant factor influencing the availability of vessels that transport refined petroleum products. Marine vessel owners are phasing in the requirement based on the age of the vessel and some older vessels are being redeployed into use in other jurisdictions rather than being retrofitted with a double-hull for use in the United States.

Cochin Pipeline System

Our Cochin pipeline system consists of an approximate 1,900-mile, 12-inch diameter multi-product pipeline operating between Fort Saskatchewan, Alberta and Windsor, Ontario, including five terminals.

The pipeline operates on a batched basis and has an estimated system capacity of approximately 70,000 barrels per day. It includes 31 pump stations spaced at 60 mile intervals and five United States propane terminals. Underground storage is available at Fort Saskatchewan, Alberta and Windsor, Ontario through third parties. In 2007, the pipeline system transported approximately 40,600 barrels per day of natural gas liquids.

Markets. The pipeline traverses three provinces in Canada and seven states in the United States transporting high vapor pressure ethane, propane, butane and natural gas liquids to the Midwestern United States and eastern Canadian petrochemical and fuel markets. Current operations involve only the transportation of propane on Cochin.

Supply. Injection into the system can occur from BP, Provident, Keyera or Dow facilities with connections at Fort Saskatchewan, Alberta and from Spectra at interconnects at Regina and Richardson, Saskatchewan.

Competition. The pipeline competes with railcars and Enbridge Energy Partners for natural gas liquids long-haul business from Fort Saskatchewan, Alberta and Windsor, Ontario. The pipeline's primary competition in the Chicago natural gas liquids market comes from the combination of the Alliance pipeline system, which brings unprocessed gas into the United States from Canada, and from Aux Sable, which processes and markets the natural gas liquids in the Chicago market.

Cypress Pipeline

Our Cypress pipeline is an interstate common carrier natural gas liquids pipeline originating at storage facilities in Mont Belvieu, Texas and extending 104 miles east to a major petrochemical producer in the Lake Charles, Louisiana area. Mont Belvieu, located approximately 20 miles east of Houston, is the largest hub for natural gas liquids gathering, transportation, fractionation and storage in the United States.

Markets. The pipeline was built to service Westlake Petrochemicals Corporation in the Lake Charles, Louisiana area under a 20-year ship-or-pay agreement that expires in 2011. The contract requires a minimum volume of 30,000 barrels per day.

Supply. The Cypress pipeline originates in Mont Belvieu where it is able to receive ethane and ethane/propane mix from local storage facilities. Mont Belvieu has facilities to fractionate natural gas liquids received from several pipelines into ethane and other components. Additionally, pipeline systems that transport natural gas liquids from major producing areas in Texas, New Mexico, Louisiana, Oklahoma and the Mid-Continent Region supply ethane and ethane/propane mix to Mont Belvieu.

Competition. The pipeline's primary competition into the Lake Charles market comes from Louisiana onshore and offshore natural gas liquids.

Southeast Terminals

Our Southeast terminal operations consist of Kinder Morgan Southeast Terminals LLC and its consolidated affiliate, Guilford County Terminal Company, LLC. Kinder Morgan Southeast Terminals LLC, a wholly-owned subsidiary referred to in this report as KMST, was formed for the purpose of acquiring and operating high-quality liquid petroleum products terminals located primarily along the Plantation/Colonial pipeline corridor in the Southeastern United States.

Combined, our Southeast terminal operations consist of 24 petroleum products terminals with a total storage capacity of approximately 8.0 million barrels. These terminals transferred approximately 361,000 barrels of refined products per day during 2007 and approximately 347,000 barrels of refined products per day during 2006.

Markets. KMST's acquisition and marketing activities are focused on the Southeastern United States from Mississippi through Virginia, including Tennessee. The primary function involves the receipt of petroleum products from common carrier pipelines, short-term storage in terminal tankage, and subsequent loading onto tank trucks. KMST also offered ethanol blending and storage services in northern Virginia during 2007. Longer term storage is available at many of the terminals. KMST has a physical presence in markets representing almost 80% of the pipeline-supplied demand in the Southeast and offers a competitive alternative to marketers seeking a relationship with a truly independent truck terminal service provider.

Supply. Product supply is predominately from Plantation and/or Colonial pipelines. To the maximum extent practicable, we endeavor to connect KMST terminals to both Plantation and Colonial.

Competition. There are relatively few independent terminal operators in the Southeast. Most of the refined petroleum products terminals in this region are owned by large oil companies (BP, Motiva, Citgo, Marathon, and Chevron) who use these assets to support their own proprietary market demands as well as product exchange activity. These oil companies are not generally seeking third party throughput customers. Magellan Midstream Partners and TransMontaigne Product Services represent the other significant independent terminal operators in this region.

Transmix Operations

Our Transmix operations include the processing of petroleum pipeline transmix, a blend of dissimilar refined petroleum products that have become co-mingled in the pipeline transportation process. During pipeline transportation, different products are transported through the pipelines abutting each other, and generate a volume of different mixed products called transmix. At our transmix processing facilities, we process and separate pipeline transmix into pipeline-quality gasoline and light distillate products. We process transmix at six separate processing facilities located in Colton, California; Richmond, Virginia; Dorsey Junction, Maryland; Indianola, Pennsylvania; Wood River, Illinois; and Greensboro, North Carolina. Combined, our transmix facilities processed approximately 10.4 million barrels of transmix in 2007 and approximately 9.1 million barrels in 2006.

In 2007, we increased the processing capacity of the recently constructed Greensboro, North Carolina transmix facility to better serve the needs of Plantation. The facility, which is located within KMST's refined products tank farm, now has the capability to process approximately 8,500 barrels of transmix per day. In addition to providing additional processing business, the facility continues to provide Plantation a lower cost alternative compared to other transmix processing arrangements that recover ultra low sulfur diesel, and also more fully utilizes current KMST tankage at the Greensboro, North Carolina tank farm.

Markets. The Gulf and East Coast refined petroleum products distribution system, particularly the Mid-Atlantic region, is the target market for our East Coast transmix processing operations. The Mid-Continent area and the New York Harbor are the target markets for our Illinois and Pennsylvania assets, respectively. Our West Coast transmix processing operations support the markets served by our Pacific operations in Southern California.

Supply. Transmix generated by Plantation, Colonial, Explorer, Sun, Teppco, and our Pacific operations provide the vast majority of the supply. These suppliers are committed to the use of our transmix facilities under long-term contracts. Individual shippers and terminal operators provide additional supply. Shell acquires transmix for processing at Indianola, Richmond and Wood River; Colton is supplied by pipeline shippers of our Pacific operations; Dorsey Junction is supplied by Colonial Pipeline Company and Greensboro is supplied by Plantation.

Competition. Placid Refining is our main competitor in the Gulf Coast area. There are various processors in the Mid-Continent area, primarily ConocoPhillips, Gladieux Refining and Williams Energy Services, who compete with our transmix facilities. Motiva Enterprises's transmix facility located near Linden, New Jersey is the principal competition for New York Harbor transmix supply and for our Indianola facility. A number of smaller organizations operate transmix processing facilities in the West and Southwest. These operations compete for supply that we envision as the basis for growth in the West and Southwest. Our Colton processing facility also competes with major oil company refineries in California.

Natural Gas Pipelines

Our Natural Gas Pipelines segment contains both interstate and intrastate pipelines. Its primary businesses consist of natural gas sales, transportation, storage, gathering, processing and treating. Within this segment, we own approximately 14,700 miles of natural gas pipelines and associated storage and supply lines that are strategically located at the center of the North American pipeline grid. Our transportation network provides access to the major gas supply areas in the western United States, Texas and the Midwest, as well as major consumer markets.

Texas Intrastate Natural Gas Pipeline Group

The group, which operates primarily along the Texas Gulf Coast, consists of the following four natural gas pipeline systems:

- our Kinder Morgan Texas Pipeline;
- our Kinder Morgan Tejas Pipeline;
- our Mier-Monterrey Mexico Pipeline; and
- our Kinder Morgan North Texas Pipeline.

The two largest systems in the group are our Kinder Morgan Texas Pipeline and our Kinder Morgan Tejas Pipeline. These pipelines essentially operate as a single pipeline system, providing customers and suppliers with improved flexibility and reliability. The combined system includes approximately 6,000 miles of intrastate natural gas pipelines with a peak transport and sales capacity of approximately 5.2 billion cubic feet per day of natural gas and approximately 120 billion cubic feet of system natural gas storage capacity. In addition, the combined system, through owned assets and contractual arrangements with third parties, has the capability to process 915 million cubic feet per day of natural gas for liquids extraction and to treat approximately 250 million cubic feet per day of natural gas for carbon dioxide removal.

Collectively, the combined system primarily serves the Texas Gulf Coast by selling, transporting, processing and treating gas from multiple onshore and offshore supply sources to serve the Houston/Beaumont/Port Arthur industrial markets, local gas distribution utilities, electric utilities and merchant power generation markets. It serves as a buyer and seller of natural gas, as well as a transporter of natural gas. The purchases and sales of natural gas are primarily priced with reference to market prices in the consuming region of its system. The difference between the purchase and sale prices is the rough equivalent of a transportation fee and fuel costs.

Included in the operations of our Kinder Morgan Tejas system is our Kinder Morgan Border Pipeline system. Kinder Morgan Border owns and operates an approximately 97-mile, 24-inch diameter pipeline that extends from a point of interconnection with the pipeline facilities of Pemex Gas Y Petroquimica Basica at the International Border between the United States and Mexico, to a point of interconnection with other intrastate pipeline facilities of Kinder Morgan Tejas located at King Ranch, Kleburg County, Texas. The 97-mile pipeline, referred to as the import/export facility, is capable of importing Mexican gas into the United States, and exporting domestic gas to Mexico. The imported Mexican gas is received from, and the exported domestic gas is delivered to, Pemex. The capacity of the import/export facility is approximately 300 million cubic feet of natural gas per day.

Our Mier-Monterrey Pipeline consists of a 95-mile, 30-inch diameter natural gas pipeline that stretches from south Texas to Monterrey, Mexico and can transport up to 375 million cubic feet per day. The pipeline connects to a 1,000-megawatt power plant complex and to the PEMEX natural gas transportation system. We have entered into a long-term contract (expiring in 2018) with Pemex, which has subscribed for all of the pipeline’s capacity.

Our Kinder Morgan North Texas Pipeline consists of an 86-mile, 30-inch diameter pipeline that transports natural gas from an interconnect with the facilities of Natural Gas Pipeline Company of America LLC, referred to in this report as NGPL, in Lamar County, Texas to a 1,750-megawatt electric generating facility located in Forney, Texas, 15 miles east of Dallas, Texas. It has the capacity to transport 325 million cubic feet per day of natural gas and is fully subscribed under a long-term contract that expires in 2032. In 2006, the existing system was enhanced to be bi-directional, so that deliveries of additional supply coming out of the Barnett Shale area can be delivered into NGPL’s pipeline as well as power plants in the area.

We also own and operate various gathering systems in South and East Texas. These systems aggregate natural gas supplies into our main transmission pipelines, and in certain cases, aggregate natural gas that must be processed or treated at its own or third-party facilities. We own plants that can process up to 115 million cubic feet per day of natural gas for liquids extraction. In addition, we have contractual rights to process approximately 800 million cubic feet per day of natural gas at various third-party owned facilities. We also own and operate three natural gas treating plants that provide carbon dioxide and/or hydrogen sulfide removal. We can treat up to 155 million cubic feet per day of natural gas for carbon dioxide removal at our Fandango Complex in Zapata County, Texas, 50 million cubic feet per day of natural gas at our Indian Rock Plant in Upshur County, Texas and approximately 45 million cubic feet per day of natural gas at our Thompsonville Facility located in Jim Hogg County, Texas.

Our North Dayton natural gas storage facility, located in Liberty County, Texas, has two existing storage caverns providing approximately 6.3 billion cubic feet of total capacity, consisting of 4.2 billion cubic feet of working capacity and 2.1 billion cubic feet of cushion gas. We have entered into a long-term storage capacity and transportation agreement with NRG covering two billion cubic feet of natural gas working capacity that expires in March 2017. In June 2006, we announced an expansion project that will significantly increase natural gas storage capacity at our North Dayton facility. The project is now expected to cost between $105 million and $115 million and involves the development of a new underground storage cavern that will add an estimated 6.5 billion cubic feet of incremental working natural gas storage capacity. The additional capacity is expected to be available in mid-2010.

We also own the West Clear Lake natural gas storage facility located in Harris County, Texas. Under a long term contract that expires in 2012, Coral Energy Resources, L.P. operates the facility and controls the 96 billion cubic feet of natural gas working capacity, and we provide transportation service into and out of the facility.

Additionally, we lease a salt dome storage facility located near Markham, Texas according to the provisions of an operating lease that expires in March 2013. We can, at our sole option, extend the term of this lease for two additional ten-year periods. The facility was expanded in 2007 and now consists of four salt dome caverns with approximately 17.3 billion cubic feet of working natural gas capacity and up to 1.1 billion cubic feet per day of peak deliverability. We also lease two salt dome caverns, known as the Stratton Ridge Facilities, from BP America Production Company in Brazoria County, Texas. The Stratton Ridge Facilities have a combined working natural gas capacity of 1.4 billion cubic feet and a peak day deliverability of 100 million cubic feet per day. A lease with Dow Hydrocarbon & Resources, Inc. for a salt dome cavern containing approximately 5.0 billion cubic feet of working capacity expired during the third quarter of 2007.

Markets. Texas is one of the largest natural gas consuming states in the country. The natural gas demand profile in our Texas intrastate pipeline group's market area is primarily composed of industrial (including on-site cogeneration facilities), merchant and utility power, and local natural gas distribution consumption. The industrial demand is primarily year-round load. Merchant and utility power demand peaks in the summer months and is complemented by local natural gas distribution demand that peaks in the winter months. As new merchant gas fired generation has come online and displaced traditional utility generation, we have successfully attached many of these new generation facilities to our pipeline systems in order to maintain and grow our share of natural gas supply for power generation. Additionally, in 2007, we have increased our capability and commitment to serve the growing local natural gas distribution market in the greater Houston metropolitan area.

We serve the Mexico market through interconnection with the facilities of Pemex at the United States-Mexico border near Arguellas, Mexico and our Mier-Monterrey Mexico pipeline. In 2007, deliveries through the existing interconnection near Arguellas fluctuated from zero to approximately 206 million cubic feet per day of natural gas, and there were several days of exports to the United States which ranged up to 250 million cubic feet per day. Deliveries to Monterrey also generally ranged from zero to 312 million cubic feet per day. We primarily provide transport service to these markets on a fee for service basis, including a significant demand component, which is paid regardless of actual throughput. Revenues earned from our activities in Mexico are paid in U.S. dollar equivalent.

Supply. We purchase our natural gas directly from producers attached to our system in South Texas, East Texas, West Texas and along the Texas Gulf Coast. In addition, we also purchase gas at interconnects with third-party interstate and intrastate pipelines. While our intrastate group does not produce gas, it does maintain an active well connection program in order to offset natural declines in production along its system and to secure supplies for additional demand in its market area. Our intrastate system has access to both onshore and offshore sources of supply, and is well positioned to interconnect with liquefied natural gas projects currently under development by others along the Texas Gulf Coast.

Competition. The Texas intrastate natural gas market is highly competitive, with many markets connected to multiple pipeline companies. We compete with interstate and intrastate pipelines, and their shippers, for attachments to new markets and supplies and for transportation, processing and treating services.

Rocky Mountain Natural Gas Pipeline Group

The group, which operates primarily along the Rocky Mountain region of the Western portion of the United States, consists of the following four natural gas pipeline systems:

- our Kinder Morgan Interstate Gas Transmission Pipeline;
- our Trailblazer Pipeline;
- our Trans-Colorado Pipeline; and
- our 51% ownership interest in the Rockies Express Pipeline.

Kinder Morgan Interstate Gas Transmission LLC

Kinder Morgan Interstate Gas Transmission LLC, referred to in this report as KMIGT, owns approximately 5,100 miles of transmission lines in Wyoming, Colorado, Kansas, Missouri and Nebraska. The pipeline system is powered by 28 transmission and storage compressor stations with approximately 160,000 horsepower. KMIGT also owns the Huntsman natural gas storage facility, located in Cheyenne County, Nebraska, which has approximately 10 billion cubic feet of firm capacity commitments and provides for withdrawal of up to 169 million cubic feet of natural gas per day.

Under transportation agreements and FERC tariff provisions, KMIGT offers its customers firm and interruptible transportation and storage services, including no-notice service and park and loan services. For these services, KMIGT charges rates which include the retention of fuel and gas lost and unaccounted for in-kind. Under KMIGT's tariffs, firm transportation and storage customers pay reservation charges each month plus a commodity charge based on the actual transported or stored volumes. In contrast, interruptible transportation and storage customers pay a commodity charge based upon actual transported and/or stored volumes. Under the no-notice service, customers pay a fee for the right to use a combination of firm storage and firm transportation to effect deliveries of natural gas up to a specified volume without making specific nominations. KMIGT also has the authority to make gas purchases and sales, as needed for system operations, pursuant to its currently effective FERC gas tariff.

KMIGT also offers its Cheyenne Market Center service, which provides nominated storage and transportation service between its Huntsman storage field and multiple interconnecting pipelines at the Cheyenne Hub, located in Weld County, Colorado. This service is fully subscribed through May 2014.

Markets. Markets served by KMIGT provide a stable customer base with expansion opportunities due to the system's access to growing Rocky Mountain supply sources. Markets served by KMIGT are comprised mainly of local natural gas distribution companies and interconnecting interstate pipelines in the mid-continent area. End-users of the local natural gas distribution companies typically include residential, commercial, industrial and agricultural customers. The pipelines interconnecting with KMIGT in turn deliver gas into multiple markets including some of the largest population centers in the Midwest. Natural gas demand to power pumps for crop irrigation during the summer from time-to-time exceeds heating season demand and provides KMIGT relatively consistent volumes throughout the year. In addition, KMIGT has seen a significant increase in demand from ethanol producers, and is actively seeking ways to meet the demands from the ethanol producing community.

Supply. Approximately 7%, by volume, of KMIGT's firm contracts expire within one year and 51% expire within one to five years. Over 99% of the system's total firm transport capacity is currently subscribed, with 78% of the total contracted capacity held by KMIGT's top nine shippers.

Competition. KMIGT competes with other interstate and intrastate gas pipelines transporting gas from the supply sources in the Rocky Mountain and Hugoton Basins to mid-continent pipelines and market centers.

Trailblazer Pipeline Company LLC

Our subsidiary, Trailblazer Pipeline Company LLC, owns a 436-mile natural gas pipeline system. Trailblazer's pipeline originates at an interconnection with Wyoming Interstate Company Ltd.'s pipeline system near Rockport, Colorado and runs through southeastern Wyoming to a terminus near Beatrice, Nebraska where it interconnects with NGPL and Northern Natural Gas Company's pipeline systems. NGPL, an investee of Knight, manages, maintains and operates Trailblazer, for which it is reimbursed at cost.

Trailblazer provides transportation services to third-party natural gas producers, marketers, local distribution companies and other shippers. Pursuant to transportation agreements and FERC tariff provisions, Trailblazer offers its customers firm and interruptible transportation. Under Trailblazer's tariffs, firm transportation customers pay reservation charges each month plus a commodity charge based on actual volumes transported. Interruptible transportation customers pay a commodity charge based upon actual volumes transported.

Markets. Significant growth in Rocky Mountain natural gas supplies has prompted a need for additional pipeline transportation service. Trailblazer has a certificated capacity of 846 million cubic feet per day of natural gas.

Supply. As of December 31, 2007, none of Trailblazer's firm contracts, by volume, expire before one year and 54%, by volume, expire within one to five years. Affiliated entities have contracted for less than 1% of the total firm transportation capacity. All of the system's firm transport capacity is currently subscribed.

Competition. The main competition that Trailblazer currently faces is that the gas supply in the Rocky Mountain area either stays in the area or is moved west and therefore is not transported on Trailblazer's pipeline. In addition, El Paso's Cheyenne Plains Pipeline can transport approximately 730 million cubic feet per day of natural gas from Weld County, Colorado to Greensburg, Kansas and competes with Trailblazer for natural gas pipeline transportation demand from the Rocky Mountain area. Additional competition could come from the Rockies Express pipeline system or from proposed pipeline projects. No assurance can be given that additional competing pipelines will not be developed in the future.

TransColorado Gas Transmission Company LLC

Our subsidiary, TransColorado Gas Transmission Company LLC, owns a 300-mile interstate natural gas pipeline that extends from approximately 20 miles southwest of Meeker, Colorado to Bloomfield, New Mexico. It has multiple points of interconnection with various interstate and intrastate pipelines, gathering systems, and local distribution companies. The pipeline system is powered by eight compressor stations having an aggregate of approximately 39,000 horsepower. Knight manages, maintains and operates TransColorado, for which it is reimbursed at cost.

TransColorado has the ability to flow gas south or north. TransColorado receives gas from one coal seam natural gas treating plant located in the San Juan Basin of Colorado and from pipeline, processing plant and gathering system interconnections within the Paradox and Piceance Basins of western Colorado. Gas flowing south through the pipeline moves onto the El Paso, Transwestern and Questar Southern Trail pipeline systems. Gas moving north flows into the Colorado Interstate, Wyoming Interstate and Questar pipeline systems at the Greasewood Hub and the Rockies Express pipeline system at the Meeker Hub. TransColorado provides transportation services to third-party natural gas producers, marketers, gathering companies, local distribution companies and other shippers.

Pursuant to transportation agreements and FERC tariff provisions, TransColorado offers its customers firm and interruptible transportation and interruptible park and loan services. For these services, TransColorado charges rates which include the retention of fuel and gas lost and unaccounted for in-kind. Under TransColorado's tariffs, firm transportation customers pay reservation charges each month plus a commodity charge based on actual volumes transported. Interruptible transportation customers pay a commodity charge based upon actual volumes transported. The underlying reservation and commodity charges are assessed pursuant to a maximum recourse rate structure, which does not vary based on the distance gas is transported. TransColorado has the authority to negotiate rates with customers if it has first offered service to those customers under its reservation and commodity charge rate structure.

TransColorado's approximately $50 million Blanco-Meeker Expansion Project was completed in the fourth quarter of 2007 and placed into service on January 1, 2008. The project boosted capacity on the pipeline by approximately 250 million cubic feet per day of natural gas from the Blanco Hub area in San Juan County, New Mexico through TransColorado's existing pipeline for deliveries to the Rockies Express Pipeline at an existing point of interconnection located at the Meeker Hub in Rio Blanco County, Colorado. All of the incremental capacity is subscribed under a long-term contract with ConocoPhillips.

Markets. TransColorado acts principally as a feeder pipeline system from the developing natural gas supply basins on the Western Slope of Colorado into the interstate natural gas pipelines that lead away from the Blanco Hub area of New Mexico and the interstate natural gas pipelines that lead away eastward from northwestern Colorado and southwestern Wyoming. TransColorado is one of the largest transporters of natural gas from the Western Slope supply basins of Colorado and provides a competitively attractive outlet for that developing natural gas resource. In 2007, TransColorado transported an average of approximately 734 million cubic feet per day of natural gas from these supply basins.

Supply. During 2007, 94% of TransColorado's transport business was with producers or their own marketing affiliates, and 6% was with marketing companies and various gas marketers. Approximately 64% of TransColorado's transport business in 2007 was conducted with its two largest customers. All of TransColorado's southbound pipeline capacity is committed under firm transportation contracts that extend at least through year-end 2008. TransColorado's pipeline capacity is 62% subscribed during 2009 through 2012, and TransColorado is actively pursuing contract extensions and or replacement contracts to increase firm subscription levels beyond 2008.

Competition. TransColorado competes with other transporters of natural gas in each of the natural gas supply basins it serves. These competitors include both interstate and intrastate natural gas pipelines and natural gas gathering systems. TransColorado's shippers compete for market share with shippers drawing upon gas production facilities within the New Mexico portion of the San Juan Basin. TransColorado has phased its past construction and expansion efforts to coincide with the ability of the interstate pipeline grid at Blanco, New Mexico to accommodate greater natural gas volumes. TransColorado's transport concurrently ramped up over that period such that TransColorado now enjoys a growing share of the outlet from the San Juan Basin to the southwestern United States marketplace.

Historically, the competition faced by TransColorado with respect to its natural gas transportation services has generally been based upon the price differential between the San Juan and Rocky Mountain basins. New pipelines servicing these producing basins have had the effect of reducing that price differential; however, given the growth in the Piceance and Paradox basins and the direct accessibility of the TransColorado system to these basins, we believe that TransColorado's transport business to be sustainable and not significantly impacted by any new entry of competition.

Rockies Express Pipeline

We operate and currently own 51% of the 1,679-mile Rockies Express Pipeline system, which when fully completed, will be one of the largest natural gas pipelines ever constructed in North America. The approximately $4.9 billion project will have the capability to transport 1.8 billion cubic feet per day of natural gas, and binding firm commitments have been secured for virtually all of the pipeline capacity.

Our ownership is through our 51% interest in West2East Pipeline LLC. the sole owner of Rockies Express Pipeline LLC. Sempra Pipelines & Storage, a unit of Sempra Energy, and ConocoPhillips hold the remaining ownership interests in the Rockies Express project. We account for our investment under the equity method of accounting due to the fact that our ownership interest will be reduced to 50% when construction of the entire project is completed. At that time, the capital accounts of West2East Pipeline LLC will be trued up to reflect our 50% economics in the project. We do not anticipate any additional changes in the ownership structure of the project.

On August 9, 2005, the FERC approved Rockies Express Pipeline LLC's application to construct 327 miles of pipeline facilities in two phases. Phase I consisted of the following two pipeline segments: (i) a 136-mile, 36-inch diameter pipeline that extends from the Meeker Hub in Rio Blanco County, Colorado to the Wamsutter Hub in Sweetwater County, Wyoming; and (ii) a 191-mile, 42-inch diameter pipeline that extends from the Wamsutter Hub to the Cheyenne Hub in Weld County, Colorado. Phase II of the project includes the construction of three compressor stations referred to as the Meeker, Big Hole and Wamsutter compressor stations. The Meeker and Wamsutter stations were completed and placed in-service in January 2008. Construction of the Big Hole compressor station is planned to commence in the second quarter of 2008, in order to meet an expected in-service date of June 30, 2009.

On April 19, 2007 the FERC issued a final order approving Rockies Express Pipeline LLC's application for authorization to construct and operate certain facilities comprising its proposed Rockies Express-West Project. This project is the first planned segment extension of the Rockies Express Pipeline LLC's original certificated facilities, and is comprised of approximately 713 miles of 42-inch diameter pipeline extending eastward from the Cheyenne Hub to an interconnection with Panhandle Eastern Pipe Line located in Audrain County, Missouri. The segment extension transports approximately 1.5 billion cubic feet per day of natural gas across the following five states: Wyoming, Colorado, Nebraska, Kansas and Missouri and includes certain improvements to pre-existing Rockies Express facilities located to the west of the Cheyenne Hub. Construction of the Rockies Express-West project commenced on May 21, 2007, and interim firm transportation service with capacity of approximately 1.4 billion cubic feet per day began January 12, 2008. The entire project (Rockies Express-West pipeline segment) is expected to become fully operational in mid-March 2008.

On April 30, 2007, Rockies Express Pipeline LLC filed an application with the FERC requesting approval to construct and operate the REX-East Project, the third segment of the Rockies Express pipeline system. The REX-East Project will be comprised of approximately 639 miles of 42-inch diameter pipeline commencing from the terminus of the Rockies Express-West pipeline in Audrain County, Missouri to a terminus near the town of

Clarington in Monroe County, Ohio. The pipeline segment will be capable of transporting approximately 1.8 billion cubic feet per day of natural gas. The FERC issued a draft environmental report in late November 2007 for the REX-East Project, and subject to receipt of regulatory approvals, the REX-East Project is expected to begin partial service on December 31, 2008, and to be in full service in June 2009.

In December 2007, Rockies Express Pipeline LLC completed a non-binding open season undertaken to solicit market interest for the "Northeast Express Project," a 375-mile extension and expansion of the Rockies Express pipeline system from Clarington, Ohio, to Princeton, New Jersey. Significant expressions of interest were received on the Northeast Express Project and negotiations with prospective shippers to enter into binding commitments are currently underway. Subject to receipt of sufficient binding commitments and regulatory approvals, the Northeast Express Project would go into service in late 2010. When complete, the Northeast Express Project would provide up to 1.8 billion cubic feet of transportation capacity to northeast markets from the Lebanon Hub and other pipeline receipt points between Lebanon, Ohio and Clarington, Ohio.

Markets. The Rockies Express Pipeline is capable of delivering gas to multiple markets along its pipeline system, primarily through interconnects with other interstate pipeline companies and direct connects to local distribution companies. Rockies Express Pipeline’s Zone 1 encompasses receipts and deliveries of natural gas west of the Cheyenne Hub, located in Northern Colorado near Cheyenne, Wyoming. Through the Zone 1 facilities, Rockies Express can deliver gas to TransColorado Gas Transmission Company LLC in northwestern Colorado, which can in turn transport the gas further south for delivery into the San Juan Basin area. In Zone 1, Rockies Express Pipeline can also deliver gas into western Wyoming through leased capacity on the Overthrust Pipeline Company system, or through its interconnections with Colorado Interstate Gas Company and Wyoming Interstate Company in southern Wyoming. REX-West has the ability to deliver natural gas to points at the Cheyenne Hub, which could be used in markets along the Front Range of Colorado, or could be transported further east through either Rockies Express Pipeline’s Zone 2 facilities or other pipeline systems.

Rockies Express Pipeline’s Zone 2 extends from the Cheyenne Hub to an interconnect with the Panhandle Eastern Pipeline in Audrain County, Missouri. Through the Zone 2 facilities, Rockies Express facilitates the delivery of natural gas into the Midcontinent area of the Unites States through various interconnects with other major interstate pipelines in Nebraska (Northern Natural Gas Pipeline and NGPL), Kansas (ANR Pipeline), and Missouri (Panhandle Eastern Pipeline). Rockies Express Pipeline’s transportation capacity under interim service is currently 1.4 billion cubic feet per day, and when this system is placed into full service it will be capable of delivering 1.5 billion cubic feet per day through these interconnects to the Midcontinent market.

Supply. Rockies Express Pipeline directly accesses major gas supply basins in western Colorado and western Wyoming. In western Colorado, Rockies Express Pipeline has access to gas supply from the Uinta and Piceance basins in eastern Utah and western Colorado. In western Wyoming, Rockies Express Pipeline accesses the Green River Basin through its facilities that are leased from Overthrust. With its connections to numerous other pipeline systems along its route, Rockies Express Pipeline has access to almost all of the major gas supply basins in Wyoming, Colorado and eastern Utah.

Competition. Although there are some competitors to the Rockies Express Pipeline system that provide a similar service, there are none that can compete with the economy-of-scale that Rockies Express Pipeline provides to its shippers to transport gas from the Rocky Mountain region to the Midcontinent markets. The REX-East Project, noted above, will put the Rockies Express Pipeline system in a very unique position of being the only pipeline capable of offering a large volume of transportation service from Rocky Mountain gas supply directly to customers in Ohio.

Rockies Express Pipeline could also experience competition for its Rocky Mountain gas supply from both existing and proposed systems. Questar Pipeline Company accesses many of the same basins as Rockies Express Pipeline and transports gas to its markets in Utah and to other interconnects, which have access to the California market. In addition, there are pipelines that are proposed to use Rocky Mountain gas to supply markets on the West Coast.

Kinder Morgan Louisiana Pipeline

In September 2006, we filed an application with the FERC requesting approval to construct and operate our Kinder Morgan Louisiana Pipeline. The natural gas pipeline project is expected to cost approximately $510 million and will provide approximately 3.2 billion cubic feet per day of take-away natural gas capacity from the Cheniere Sabine Pass liquefied natural gas terminal located in Cameron Parish, Louisiana. The project is supported by fully subscribed capacity and long-term customer commitments with Chevron and Total.

The Kinder Morgan Louisiana Pipeline will consist of two segments:

- a 132-mile, 42-inch diameter pipeline with firm capacity of approximately 2.0 billion cubic feet per day of natural gas that will extend from the Sabine Pass terminal to a point of interconnection with an existing Columbia Gulf Transmission line in Evangeline Parish, Louisiana (an offshoot will consist of approximately 2.3 miles of 24-inch diameter pipeline with firm peak day capacity of approximately 300 million cubic feet per day extending away from the 42-inch diameter line to the existing Florida Gas Transmission Company compressor station in Acadia Parish, Louisiana). This segment is expected to be in service by January 1, 2009; and

- a 1-mile, 36-inch diameter pipeline with firm capacity of approximately 1.2 billion cubic feet per day that will extend from the Sabine Pass terminal and connect to NGPL's natural gas pipeline. This portion of the project is expected to be in service in the third quarter of 2008.

We have designed and will construct the Kinder Morgan Louisiana Pipeline in a manner that will minimize environmental impacts, and where possible, existing pipeline corridors will be used to minimize impacts to communities and to the environment. As of December 31, 2007, there were no major pipeline re-routes as a result of any landowner requests.

Midcontinent Express Pipeline LLC

On October 9, 2007, Midcontinent Express Pipeline LLC filed an application with the FERC requesting a certificate of public convenience and necessity that would authorize construction and operation of the approximate 500-mile Midcontinent Express Pipeline natural gas transmission system. We currently own a 50% interest in Midcontinent Express Pipeline LLC and we account for our investment under the equity method of accounting. Energy Transfer Partners, L.P. owns the remaining 50% interest. The Midcontinent Express Pipeline will create long-haul, firm natural gas transportation takeaway capacity, either directly or indirectly, from natural gas producing regions located in Texas, Oklahoma and Arkansas. The total project is expected to cost approximately $1.3 billion, and will have an initial transportation capacity of approximately 1.4 billion cubic feet per day of natural gas.

For additional information regarding the Midcontinent Express Pipeline, see "(a) General Development of Business—Recent Developments."

Casper and Douglas Natural Gas Processing Systems

We own and operate our Casper and Douglas, Wyoming natural gas processing plants, which have the capacity to process up to 185 million cubic feet per day of natural gas depending on raw gas quality.

Markets. Casper and Douglas are processing plants servicing gas streams flowing into KMIGT. Natural gas liquids processed by our Casper plant are sold into local markets consisting primarily of retail propane dealers and oil refiners. Natural gas liquids processed by our Douglas plant are sold to ConocoPhillips via their Powder River natural gas liquids pipeline for either ultimate consumption at the Borger refinery or for further disposition to the natural gas liquids trading hubs located in Conway, Kansas and Mont Belvieu, Texas.

Competition. Other regional facilities in the Greater Powder River Basin include the Hilight plant (80 million cubic feet per day) owned and operated by Anadarko, the Sage Creek plant (50 million cubic feet per day) owned and operated by Merit Energy, and the Rawlins plant (230 million cubic feet per day) owned and operated by El

Paso. Casper and Douglas, however, are the only plants which provide straddle processing of natural gas flowing into KMIGT.

Red Cedar Gathering Company

We own a 49% equity interest in the Red Cedar Gathering Company, a joint venture organized in August 1994 and referred to in this report as Red Cedar. The remaining 51% interest in Red Cedar is owned by the Southern Ute Indian Tribe. Red Cedar owns and operates natural gas gathering, compression and treating facilities in the Ignacio Blanco Field in La Plata County, Colorado. The Ignacio Blanco Field lies within the Colorado portion of the San Juan Basin, most of which is located within the exterior boundaries of the Southern Ute Indian Tribe Reservation. Red Cedar gathers coal seam and conventional natural gas at wellheads and several central delivery points, for treating, compression and delivery into any one of four major interstate natural gas pipeline systems and an intrastate pipeline.

Red Cedar also owns Coyote Gas Treating, LLC, referred to in this report as Coyote Gulch. The sole asset owned by Coyote Gulch is a 250 million cubic feet per day natural gas treating facility located in La Plata County, Colorado. The inlet gas stream treated by Coyote Gulch contains an average carbon dioxide content of between 12% and 13%. The plant treats the gas down to a carbon dioxide concentration of 2% in order to meet interstate natural gas pipeline quality specifications, and then compresses the natural gas into the TransColorado Gas Transmission pipeline for transport to the Blanco, New Mexico-San Juan Basin Hub.

Red Cedar’s gas gathering system currently consists of over 1,100 miles of gathering pipeline connecting more than 920 producing wells, 85,000 horsepower of compression at 24 field compressor stations and two carbon dioxide treating plants. The capacity and throughput of the Red Cedar system as currently configured is approximately 750 million cubic feet per day of natural gas.

Thunder Creek Gas Services, LLC

We own a 25% equity interest in Thunder Creek Gas Services, LLC, referred to in this report as Thunder Creek. Devon Energy owns the remaining 75%. Thunder Creek provides gathering, compression and treating services to a number of coal seam gas producers in the Powder River Basin of Wyoming. Throughput volumes include both coal seam and conventional plant residue gas.

Thunder Creek’s operations are a combination of mainline and low pressure gathering assets. The mainline assets include 125 miles of mainline pipeline, 230 miles of high and low pressure laterals, 26,635 horsepower of mainline compression and carbon dioxide removal facilities consisting of a 220 million cubic feet per day carbon dioxide treating plant complete with dehydration. The mainline assets receive gas from 53 receipt points and can deliver treated gas to seven delivery points including Colorado Interstate Gas, Wyoming Interstate Gas Company, KMIGT and three power plants. The low pressure gathering assets include five systems consisting of 194 miles of gathering pipeline and 35,329 horsepower of field compression.

CO_2

Our CO_2 segment consists of Kinder Morgan CO_2 Company, L.P. and its consolidated affiliates, referred to in this report as KMCO_2. Carbon dioxide is used in enhanced oil recovery projects as a flooding medium for recovering crude oil from mature oil fields. Our carbon dioxide pipelines and related assets allow us to market a complete package of carbon dioxide supply, transportation and technical expertise to the customer. Together, our CO_2 business segment produces, transports and markets carbon dioxide for use in enhanced oil recovery operations. We also hold ownership interests in several oil-producing fields and own a 450-mile crude oil pipeline, all located in the Permian Basin region of West Texas.

Carbon Dioxide Reserves

We own approximately 45% of, and operate, the McElmo Dome unit in Colorado, which contains more than nine trillion cubic feet of recoverable carbon dioxide. Deliverability and compression capacity exceeds one billion cubic feet per day. We are currently installing facilities and drilling 8 wells to increase the production capacity from

McElmo Dome by approximately 200 million cubic feet per day. We also own approximately 11% of the Bravo Dome unit in New Mexico, which contains more than one trillion cubic feet of recoverable carbon dioxide and produces approximately 290 million cubic feet per day.

We also own approximately 88% of the Doe Canyon Deep unit in Colorado, which contains more than 1.5 trillion cubic feet of carbon dioxide. We have installed facilities and drilled six wells to produce approximately 100 million cubic feet per day of carbon dioxide beginning in January 2008.

Markets. Our principal market for carbon dioxide is for injection into mature oil fields in the Permian Basin, where industry demand is expected to grow modestly for the next several years. We are exploring additional potential markets, including enhanced oil recovery targets in California, Wyoming, the Gulf Coast, Mexico, and Canada, and coal bed methane production in the San Juan Basin of New Mexico.

Competition. Our primary competitors for the sale of carbon dioxide include suppliers that have an ownership interest in McElmo Dome, Bravo Dome and Sheep Mountain carbon dioxide reserves, and Petro-Source Carbon Company, which gathers waste carbon dioxide from natural gas production in the Val Verde Basin of West Texas. There is no assurance that new carbon dioxide sources will not be discovered or developed, which could compete with us or that new methodologies for enhanced oil recovery will not replace carbon dioxide flooding.

Carbon Dioxide Pipelines

As a result of our 50% ownership interest in Cortez Pipeline Company, we own a 50% equity interest in and operate the approximate 500-mile, Cortez pipeline. The pipeline carries carbon dioxide from the McElmo Dome and Doe Canyon source fields near Cortez, Colorado to the Denver City, Texas hub. The Cortez pipeline currently transports over one billion cubic feet of carbon dioxide per day, including approximately 99% of the carbon dioxide transported downstream on our Central Basin pipeline and our Centerline pipeline. The tariffs charged by Cortez Pipeline are not regulated.

Our Central Basin pipeline consists of approximately 143 miles of pipe and 177 miles of lateral supply lines located in the Permian Basin between Denver City, Texas and McCamey, Texas with a throughput capacity of 600 million cubic feet per day. At its origination point in Denver City, our Central Basin pipeline interconnects with all three major carbon dioxide supply pipelines from Colorado and New Mexico, namely the Cortez pipeline (operated by $KMCO_2$) and the Bravo and Sheep Mountain pipelines (operated by Oxy Permian). Central Basin's mainline terminates near McCamey where it interconnects with the Canyon Reef Carriers pipeline and the Pecos pipeline. The tariffs charged by the Central Basin pipeline are not regulated.

Our Centerline pipeline consists of approximately 113 miles of pipe located in the Permian Basin between Denver City, Texas and Snyder, Texas. The pipeline has a capacity of 300 million cubic feet per day. The tariffs charged by the Centerline pipeline are not regulated.

We own a 13% undivided interest in the 218-mile, Bravo pipeline, which delivers CO2 from the Bravo Dome source field in northeast New Mexico to the Denver City hub and has a capacity of more than 350 million cubic feet per day. Tariffs on the Bravo pipeline are not regulated.

In addition, we own approximately 98% of the Canyon Reef Carriers pipeline and approximately 69% of the Pecos pipeline. The Canyon Reef Carriers pipeline extends 139 miles from McCamey, Texas, to the SACROC unit. The pipeline has a capacity of approximately 290 million cubic feet per day and makes deliveries to the SACROC, Sharon Ridge, Cogdell and Reinecke units. The Pecos pipeline is a 25-mile pipeline that runs from McCamey to Iraan, Texas. It has a capacity of approximately 120 million cubic feet per day of carbon dioxide and makes deliveries to the Yates unit. The tariffs charged on the Canyon Reef Carriers and Pecos pipelines are not regulated.

Markets. The principal market for transportation on our carbon dioxide pipelines is to customers, including ourselves, using carbon dioxide for enhanced recovery operations in mature oil fields in the Permian Basin, where industry demand is expected to grow modestly for the next several years.

Competition. Our ownership interests in the Central Basin, Cortez and Bravo pipelines are in direct competition with other carbon dioxide pipelines. We also compete with other interest owners in McElmo Dome and Bravo Dome for transportation of carbon dioxide to the Denver City, Texas market area.

Oil Acreage and Wells

$KMCO_2$ also holds ownership interests in oil-producing fields, including an approximate 97% working interest in the SACROC unit, an approximate 50% working interest in the Yates unit, a 21% net profits interest in the H.T. Boyd unit, an approximate 65% working interest in the Claytonville unit, an approximate 95% working interest in the Katz CB Long unit, an approximate 64% working interest in the Katz SW River unit, a 100% working interest in the Katz East River unit, and lesser interests in the Sharon Ridge unit, the Reinecke unit and the MidCross unit, all of which are located in the Permian Basin of West Texas.

The SACROC unit is one of the largest and oldest oil fields in the United States using carbon dioxide flooding technology. The field is comprised of approximately 56,000 acres located in the Permian Basin in Scurry County, Texas. SACROC was discovered in 1948 and has produced over 1.29 billion barrels of oil since inception. It is estimated that SACROC originally held approximately 2.7 billion barrels of oil. We have expanded the development of the carbon dioxide project initiated by the previous owners and increased production over the last several years. The Yates unit is also one of the largest oil fields ever discovered in the United States. It is estimated that it originally held more than five billion barrels of oil, of which about 29% has been produced. The field, discovered in 1926, is comprised of approximately 26,000 acres located about 90 miles south of Midland, Texas.

As of December 2007, the SACROC unit had 391 producing wells, and the purchased carbon dioxide injection rate was 211 million cubic feet per day, down from an average of 247 million cubic feet per day as of December 2006. The average oil production rate for 2007 was approximately 27,600 barrels of oil per day, down from an average of approximately 30,800 barrels of oil per day during 2006. The average natural gas liquids production rate (net of the processing plant share) for 2007 was approximately 6,300 barrels per day, an increase from an average of approximately 5,700 barrels per day during 2006.

Our plan has been to increase the production rate and ultimate oil recovery from Yates by combining horizontal drilling with carbon dioxide injection to ensure a relatively steady production profile over the next several years. We are implementing our plan and as of December 2007, the Yates unit was producing about 27,600 barrels of oil per day. As of December 2006, the Yates unit was producing approximately 27,200 barrels of oil per day. Unlike our operations at SACROC, where we use carbon dioxide and water to drive oil to the producing wells, we are using carbon dioxide injection to replace nitrogen injection at Yates in order to enhance the gravity drainage process, as well as to maintain reservoir pressure. The differences in geology and reservoir mechanics between the two fields mean that substantially less capital will be needed to develop the reserves at Yates than is required at SACROC.

We also operate and own an approximate 65% gross working interest in the Claytonville oil field unit located in Fisher County, Texas. The Claytonville unit is located nearly 30 miles east of the SACROC unit in the Permian Basin of West Texas and is currently producing approximately 230 barrels of oil per day. We are presently evaluating operating and subsurface technical data from the Claytonville unit to further assess redevelopment opportunities including carbon dioxide flood operations.

We also operate and own working interests in the Katz CB Long unit, the Katz Southwest River unit and Katz East River unit. The Katz field is located in the Permian Basin area of West Texas and, as of December 2007, was producing approximately 400 barrels of oil equivalent per day. We are presently evaluating operating and subsurface technical data to further assess redevelopment opportunities for the Katz field including the potential for carbon dioxide flood operations.

The following table sets forth productive wells, service wells and drilling wells in the oil and gas fields in which we own interests as of December 31, 2007. When used with respect to acres or wells, gross refers to the total acres or wells in which we have a working interest; net refers to gross acres or wells multiplied, in each case, by the percentage working interest owned by us:

	Productive Wells (a)		Service Wells (b)		Drilling Wells (c)	
	Gross	Net	Gross	Net	Gross	Net
Crude Oil	2,463	1,587	1,066	789	2	2
Natural Gas	8	4	—	—	—	—
Total Wells	2,471	1,591	1,066	789	2	2

(a) Includes active wells and wells temporarily shut-in. As of December 31, 2007, we did not operate any productive wells with multiple completions.

(b) Consists of injection, water supply, disposal wells and service wells temporarily shut-in. A disposal well is used for disposal of saltwater into an underground formation; a service well is a well drilled in a known oil field in order to inject liquids that enhance recovery or dispose of salt water.

(c) Consists of development wells in the process of being drilled as of December 31, 2007.A development well is a well drilled in an already discovered oil field.

The oil and gas producing fields in which we own interests are located in the Permian Basin area of West Texas. The following table reflects our net productive and dry wells that were completed in each of the three years ended December 31, 2007, 2006 and 2005:

	2007	2006	2005
Productive			
Development	31	37	42
Exploratory	—	—	—
Dry			
Development	—	—	—
Exploratory	—	—	—
Total Wells	31	37	42

Notes: The above table includes wells that were completed during each year regardless of the year in which drilling was initiated, and does not include any wells where drilling operations were not completed as of the end of the applicable year. Development wells include wells drilled in the proved area of an oil or gas resevoir.

The following table reflects the developed and undeveloped oil and gas acreage that we held as of December 31, 2007:

	Gross	Net
Developed Acres	72,435	67,731
Undeveloped Acres	8,788	8,129
Total	81,223	75,860

Operating Statistics

Operating statistics from our oil and gas producing activities for each of the years 2007, 2006 and 2005 are shown in the following table:

Results of Operations for Oil and Gas Producing Activities – Unit Prices and Costs

	Year Ended December 31,		
	2007	**2006**	**2005**
Consolidated Companies(a)			
Production costs per barrel of oil equivalent(b)(c)(d)	$ 16.22	$ 13.30	$ 10.00
Crude oil production (MBbl/d)	35.6	37.8	37.9
Natural gas liquids production (MBbl/d)(d)	5.5	5.0	5.3
Natural gas liquids production from gas plants(MBbl/d)(e)	4.1	3.9	4.1
Total natural gas liquids production(MBbl/d)	9.6	8.9	9.4
Natural gas production (MMcf/d)(d)(f)	0.8	1.3	3.7
Natural gas production from gas plants(MMcf/d)(e)(f)	0.3	0.3	3.1
Total natural gas production(MMcf/d)(f)	1.1	1.6	6.8
Average sales prices including hedge gains/losses:			
Crude oil price per Bbl(g)	$ 36.05	$ 31.42	$ 27.36
Natural gas liquids price per Bbl(g)	$ 52.22	$ 43.52	$ 38.79
Natural gas price per Mcf(h)	$ 6.08	$ 6.36	$ 5.84
Total natural gas liquids price per Bbl(e)	$ 52.91	$ 43.90	$ 38.98
Total natural gas price per Mcf(e)	$ 5.89	$ 7.02	$ 5.80
Average sales prices excluding hedge gains/losses:			
Crude oil price per Bbl(g)	$ 69.63	$ 63.27	$ 54.45
Natural gas liquids price per Bbl(g)	$ 52.22	$ 43.52	$ 38.79
Natural gas price per Mcf(h)	$ 6.08	$ 6.36	$ 5.84

(a) Amounts relate to Kinder Morgan CO2 Company, L.P. and its consolidated subsidaries.

(b) Computed using production costs, excluding transportation costs, as defined by the United States Securities and Exchange Commisson. Natural gas volumes were converted to barrels of oil equivalent (BOE) using a conversion factor of six mcf of natural gas to one barrel of oil.

(c) Production costs include labor, repairs and maintenance, materials, supplies, fuel and power, property taxes, severance taxes, and general and administrative expenses directly related to oil and gas producing activities.

(d) Includes only production attributable to leasehold ownership.

(e) Includes production attributable to our ownership in processing plants and third party processing agreements.

(f) Excludes natural gas production used as fuel.

(g) Hedge gains/losses for crude oil and natural gas liquids are included with crude oil.

(h) Natural gas sales were not hedged.

See Note 20 to our consolidated financial statements included in this report for additional information with respect to operating statistics and supplemental information on our oil and gas producing activities.

Gas and Gasoline Plant Interests

We operate and own an approximate 22% working interest plus an additional 28% net profits interest in the Snyder gasoline plant. We also operate and own a 51% ownership interest in the Diamond M gas plant and a 100% ownership interest in the North Snyder plant, all of which are located in the Permian Basin of West Texas. The Snyder gasoline plant processes gas produced from the SACROC unit and neighboring carbon dioxide projects, specifically the Sharon Ridge and Cogdell units, all of which are located in the Permian Basin area of West Texas. The Diamond M and the North Snyder plants contract with the Snyder plant to process gas. Production of natural gas liquids at the Snyder gasoline plant as of December 2007 was approximately 15,500 barrels per day as compared to 15,000 barrels per day as of December 2006.

Crude Oil Pipeline

We own our Kinder Morgan Wink Pipeline, a 450-mile Texas intrastate crude oil pipeline system consisting of three mainline sections, two gathering systems and numerous truck delivery stations. The segment that runs from Wink to El Paso has a total capacity of 130,000 barrels of crude oil per day. The pipeline allows us to better manage crude oil deliveries from our oil field interests in West Texas, and we have entered into a long-term throughput agreement with Western Refining Company, L.P. to transport crude oil into Western's 120,000 barrel per day refinery in El Paso. The 20-inch pipeline segment transported approximately119,000 barrels of oil per day in 2007. The Kinder Morgan Wink Pipeline is regulated by both the FERC and the Texas Railroad Commission.

Terminals

Our Terminals segment includes the operations of our petroleum, chemical and other liquids terminal facilities (other than those included in our Products Pipelines segment) and all of our coal, petroleum coke, fertilizer, steel, ores and dry-bulk material services, including all transload, engineering, conveying and other in-plant services. Combined, the segment is composed of approximately100 owned or operated liquids and bulk terminal facilities, and more than 45 rail transloading and materials handling facilities located throughout the United States, Canada and the Netherlands. In 2007, the number of customers from whom our Terminals segment received more than $0.1 million of revenue was approximately 650.

Liquids Terminals

Our liquids terminals operations primarily store refined petroleum products, petrochemicals, industrial chemicals and vegetable oil products in aboveground storage tanks and transfer products to and from pipelines, vessels, tank trucks, tank barges, and tank railcars. Combined, our liquids terminals facilities possess liquids storage capacity of approximately 47.5 million barrels, and in 2007, these terminals handled approximately 557 million barrels of petroleum, chemicals and vegetable oil products.

In September 2006, we announced major expansions at our Pasadena and Galena Park, Texas terminal facilities. The expansions will provide additional infrastructure to help meet the growing need for refined petroleum products storage capacity along the Gulf Coast. The investment of approximately $195 million includes the construction of the following: (i) new storage tanks at both our Pasadena and Galena Park terminals; (ii) an additional cross-channel pipeline to increase the connectivity between the two terminals; (iii) a new ship dock at Galena Park; and (iv) an additional loading bay at our fully automated truck loading rack located at our Pasadena terminal. The expansions are supported by long-term customer commitments and will result in approximately 3.4 million barrels of additional tank storage capacity at the two terminals. Construction began in October 2006, and all of the projects are expected to be completed by the spring of 2008, with the exception of the of the Galena Park ship dock which is now scheduled to be in-service by the third quarter of 2008.

At Perth Amboy, New Jersey, we completed construction and placed into service nine new storage tanks with a capacity of 1.4 million barrels for gasoline, diesel and jet fuel. These tanks have been leased on a long-term basis to two customers. Our total investment in these facilities was approximately $69 million.

In June 2006, we announced the construction of a new crude oil tank farm located in Edmonton, Alberta, Canada, and long-term contracts with customers for all of the available capacity at the facility. Situated on approximately 24 acres, the new storage facility will have nine tanks with a combined storage capacity of approximately 2.2 million barrels for crude oil. Service is expected to begin in the first quarter of 2008, and when completed, the tank farm will serve as a premier blending and storage hub for Canadian crude oil. Originally estimated at $115 million, due primarily to additional labor costs, total investment in this tank farm is projected to be $162 million on a constant U.S. dollar basis. The tank farm will have access to more than 20 incoming pipelines and several major outbound systems, including a connection with our Trans Mountain pipeline system, which currently transports up to 260,000 barrels per day of heavy crude oil and refined products from Edmonton to marketing terminals and refineries located in the greater Vancouver, British Columbia area and Puget Sound in Washington state.

Competition. We are one of the largest independent operators of liquids terminals in North America. Our primary competitors are IMTT, Magellan, Morgan Stanley, NuStar, Oil Tanking, Teppco, and Vopak.

Bulk Terminals

Our bulk terminal operations primarily involve dry-bulk material handling services; however, we also provide conveyor manufacturing and installation, engineering and design services and in-plant services covering material handling, conveying, maintenance and repair, railcar switching and miscellaneous marine services. Combined, our dry-bulk and material transloading facilities handled approximately 87.1 million tons of coal, petroleum coke, fertilizers, steel, ores and other dry-bulk materials in 2007. We own or operate approximately 93 dry-bulk terminals in the United States, Canada and the Netherlands.

In May 2007, we purchased certain buildings and equipment and completed a 40 year agreement to operate Vancouver Wharves, a bulk marine terminal located at the entrance to the Port of Vancouver, British Columbia. The facility consists of five vessel berths situated on a 139-acre site, extensive rail infrastructure, dry-bulk and liquid storage, and material handling systems, which allow the terminal to handle over 3.5 million tons of cargo annually. Vancouver Wharves has access to three major rail carriers connecting to shippers in western and central Canada and the U.S. Pacific Northwest. Vancouver Wharves offers a variety of inbound, outbound and value-added services for mineral concentrates, wood products, agri-products and sulfur. In addition to the aggregate consideration of approximately $57.2 million ($38.8 million in cash and the assumption of $18.4 million of assumed liabilities) paid for this facility, we plan to invest an additional $46 million at Vancouver Wharves over the next two years to upgrade and relocate certain rail track and transloading systems, buildings and a shiploader.

Effective September 1, 2007, we purchased the assets of Marine Terminals, Inc. for an aggregate consideration of approximately $101.5 million. Combined, the assets handle approximately 13.5 million tons of alloys and steel products annually from five facilities located in the southeast United States. These strategically located terminals provide handling, processing, harboring and warehousing services primarily to Nucor Corporation, one of the largest steel and steel products companies in the world, under long-term contracts.

Competition. Our bulk terminals compete with numerous independent terminal operators, other terminals owned by oil companies, stevedoring companies, and other industrials opting not to outsource terminal services. Many of our bulk terminals were constructed pursuant to long-term contracts for specific customers. As a result, we believe other terminal operators would face a significant disadvantage in competing for this business.

Materials Services (rail transloading)

Our materials services operations include rail or truck transloading operations conducted at 45 owned and non-owned facilities. The Burlington Northern Santa Fe, CSX, Norfolk Southern, Union Pacific, Kansas City Southern and A&W railroads provide rail service for these terminal facilities. Approximately 50% of the products handled are liquids, including an entire spectrum of liquid chemicals, and 50% are dry-bulk products. Many of the facilities are equipped for bi-modal operation (rail-to-truck, and truck-to-rail) or connect via pipeline to storage facilities. Several facilities provide railcar storage services. We also design and build transloading facilities, perform inventory management services, and provide value-added services such as blending, heating and sparging. In 2007, our materials services operations handled approximately 347,000 railcars.

Competition Our material services operations compete with a variety of national transload and terminal operators across the United States, including Savage Services, Watco and Bulk Plus Logistics. Additionally, single or multi-site terminal operators are often entrenched in the network of Class 1 rail carriers.

Trans Mountain

Our Trans Mountain common carrier pipeline system originates at Edmonton, Alberta and transports crude oil and refined petroleum to destinations in the interior and on the west coast of British Columbia. A connecting pipeline owned by us delivers petroleum to refineries in the state of Washington.

Trans Mountain’s pipeline is 715 miles. The capacity of the line out of Edmonton ranges from 260,000 barrels per day when heavy crude represents 20% of the total throughput to 300,000 barrels per day with no heavy crude. The pipeline system utilizes 21 pump stations controlled by a centralized computer control system.

Trans Mountain also operates a 5.3 mile spur line from its Sumas Pump Station to the U.S. – Canada international border where it connects with a 63 mile pipeline system owned and operated by us. The pipeline system in Washington State has a sustainable throughput capacity of approximately 135,000 barrels per day when heavy crude represents approximately 25% of throughput and connects to four refineries located in northwestern Washington State. The volumes of petroleum shipped to Washington State fluctuate in response to the price levels of Canadian crude oil in relation to petroleum produced in Alaska and other offshore sources.

In 2007, deliveries on Trans Mountain averaged 258,540 barrels per day. This was an increase of 13% from average 2006 deliveries of 229,369 barrels per day. In April 2007, we commissioned ten new pump stations that boosted capacity on Trans Mountain from 225,000 to approximately 260,000 barrels per day. The crude oil and refined petroleum transported through Trans Mountain's pipeline system originates in Alberta and British Columbia. The refined and partially refined petroleum transported to Kamloops, British Columbia and Vancouver originates from oil refineries located in Edmonton. Petroleum products delivered through Trans Mountain's pipeline system are used in markets in British Columbia, Washington State and elsewhere.

Overall Alberta crude oil supply has been increasing steadily over the past few years as a result of significant oilsands development with projects led by Shell Canada, Suncor Energy and Syncrude Canada. Further development is expected to continue into the future with expansions to existing oilsands production facilities as well as with new projects. In its moderate growth case, the Canadian Association of Petroleum Producers ("CAPP") forecasts Western Canadian crude oil production to increase by over 1.6 million barrels per day by 2015. This increasing supply will likely result in constrained export pipeline capacity from Western Canada, which supports Trans Mountain's view that both the demand for transportation services provided by Trans Mountain's pipeline and the supply of crude oil will remain strong for the foreseeable future.

Shipments of refined petroleum represent a significant portion of Trans Mountain's throughput. In 2007, shipments of refined petroleum and iso-octane represented 25% of throughput, as compared with 28% in 2006.

Major Customers

Our total operating revenues are derived from a wide customer base.For each of the years ended December 31, 2007, 2006 and 2005, no revenues from transactions with a single external customer accounted for 10% or more of our total consolidated revenues. Our Texas intrastate natural gas pipeline group buys and sells significant volumes of natural gas within the state of Texas and, to a far lesser extent, our CO2 business segment also sells natural gas. Combined, total revenues from the sales of natural gas from our Natural Gas Pipelines and CO2 business segments in 2007, 2006 and 2005 accounted for 63.3%, 66.8% and 73.9%, respectively, of our total consolidated revenues.

As a result of our Texas intrastate group selling natural gas in the same price environment in which it is purchased, both our total consolidated revenues and our total consolidated purchases (cost of sales) increase considerably due to the inclusion of the cost of gas in both financial statement line items. However, these higher revenues and higher purchased gas costs do not necessarily translate into increased margins in comparison to those situations in which we charge a fee to transport gas owned by others as we seek to match the purchase and sales indexes and lock in a transport fee. We do not believe that a loss of revenues from any single customer would have a material adverse effect on our business, financial position, results of operations or cash flows.

Regulation

Interstate Common Carrier Pipeline Rate Regulation – U.S. Operations

Some of our pipelines are interstate common carrier pipelines, subject to regulation by the FERC under the Interstate Commerce Act, or ICA. The ICA requires that we maintain our tariffs on file with the FERC, which tariffs set forth the rates we charge for providing transportation services on our interstate common carrier pipelines as well as the rules and regulations governing these services. The ICA requires, among other things, that such rates on interstate common carrier pipelines be "just and reasonable" and nondiscriminatory. The ICA permits interested persons to challenge newly proposed or changed rates and authorizes the FERC to suspend the effectiveness of such rates for a period of up to seven months and to investigate such rates. If, upon completion of an investigation, the

FERC finds that the new or changed rate is unlawful, it is authorized to require the carrier to refund the revenues in excess of the prior tariff collected during the pendency of the investigation. The FERC may also investigate, upon complaint or on its own motion, rates that are already in effect and may order a carrier to change its rates prospectively. Upon an appropriate showing, a shipper may obtain reparations for damages sustained during the two years prior to the filing of a complaint.

On October 24, 1992, Congress passed the Energy Policy Act of 1992. The Energy Policy Act deemed petroleum products pipeline tariff rates that were in effect for the 365-day period ending on the date of enactment or that were in effect on the 365th day preceding enactment and had not been subject to complaint, protest or investigation during the 365-day period to be just and reasonable or "grandfathered" under the ICA. The Energy Policy Act also limited the circumstances under which a complaint can be made against such grandfathered rates. The rates we charged for transportation service on our Cypress Pipeline were not suspended or subject to protest or complaint during the relevant 365-day period established by the Energy Policy Act. For this reason, we believe these rates should be grandfathered under the Energy Policy Act. Certain rates on our Pacific operations' pipeline system were subject to protest during the 365-day period established by the Energy Policy Act. Accordingly, certain of the Pacific pipelines' rates have been, and continue to be, subject to complaints with the FERC, as is more fully described in Note 16 to our consolidated financial statements included elsewhere in this report.

Petroleum products pipelines may change their rates within prescribed ceiling levels that are tied to an inflation index. Shippers may protest rate increases made within the ceiling levels, but such protests must show that the portion of the rate increase resulting from application of the index is substantially in excess of the pipeline's increase in costs from the previous year. A pipeline must, as a general rule, utilize the indexing methodology to change its rates. The FERC, however, uses cost-of-service ratemaking, market-based rates and settlement rates as alternatives to the indexing approach in certain specified circumstances.

Common Carrier Pipeline Rate Regulation – Canadian Operations

The Canadian portion of our crude oil and refined petroleum products pipeline system is under the regulatory jurisdiction of Canada's National Energy Board, referred to in this report as the NEB. The National Energy Board Act gives the NEB power to authorize pipeline construction and to establish tolls and conditions of service. In November 2004, Trans Mountain entered into negotiations with the Canadian Association of Petroleum Producers and principal shippers for a new incentive toll settlement to be effective for the period starting January 1, 2006 and ending December 31, 2010. In January 2006, Trans Mountain reached agreement in principle, which was reduced to a memorandum of understanding for the 2006 toll settlement. A final agreement was reached with the Canadian Association of Petroleum Producers in October 2006 and NEB approval was received in November 2006.

The 2006 toll settlement incorporates an incentive toll mechanism that is intended to provide Trans Mountain with the opportunity to earn a return on equity greater than that calculated using the formula established by the NEB. In return for this opportunity, Trans Mountain has agreed to assume certain risks and provide cost certainty in certain areas. Part of the incentive toll mechanism specifies that Trans Mountain is allowed to keep 75% of the net revenue generated by throughput in excess of 92.5% of the capacity of the pipeline. The 2006 incentive toll settlement provides for base tolls which will, other than recalculation or adjustment in certain specified circumstances, remain in effect for the five-year period. The toll settlement also governs the financial arrangements for the approximately C$638 million expansions to Trans Mountain that will add 75,000 barrels per day of incremental capacity to the system by November 2008. The toll charged for the portion of Trans Mountain's pipeline system located in the United States falls under the jurisdiction of the FERC. See "Interstate Common Carrier Pipeline Rate Regulation – U.S. Operations."

Interstate Natural Gas Transportation and Storage Regulation

Both the performance of and rates charged by companies performing interstate natural gas transportation and storage services are regulated by the FERC under the Natural Gas Act of 1938 and, to a lesser extent, the Natural Gas Policy Act of 1978. Beginning in the mid-1980's, the FERC initiated a number of regulatory changes intended to create a more competitive environment in the natural gas marketplace. Among the most important of these changes were:

- Order No. 436 (1985) requiring open-access, nondiscriminatory transportation of natural gas;
- Order No. 497 (1988) which set forth new standards and guidelines imposing certain constraints on the interaction between interstate natural gas pipelines and their marketing affiliates and imposing certain disclosure requirements regarding that interaction; and
- Order No. 636 (1992) which required interstate natural gas pipelines that perform open-access transportation under blanket certificates to "unbundle" or separate their traditional merchant sales services from their transportation and storage services and to provide comparable transportation and storage services with respect to all natural gas supplies whether purchased from the pipeline or from other merchants such as marketers or producers.

Natural gas pipelines must now separately state the applicable rates for each unbundled service they provide (i.e., for the natural gas commodity, transportation and storage). Order 636 contains a number of procedures designed to increase competition in the interstate natural gas industry, including: (i) requiring the unbundling of sales services from other services; (ii) permitting holders of firm capacity on interstate natural gas pipelines to release all or a part of their capacity for resale by the pipeline; and (iii) the issuance of blanket sales certificates to interstate pipelines for unbundled services. Order 636 has been affirmed in all material respects upon judicial review, and our own FERC orders approving our unbundling plans are final and not subject to any pending judicial review.

On November 25, 2003, the FERC issued Order No. 2004, adopting revised Standards of Conduct that apply uniformly to interstate natural gas pipelines and public utilities. In light of the changing structure of the energy industry, these Standards of Conduct govern relationships between regulated interstate natural gas pipelines and all of their energy affiliates. These new Standards of Conduct were designed to eliminate the loophole in the previous regulations that did not cover an interstate natural gas pipeline’s relationship with energy affiliates that are not marketers. The rule is designed to prevent interstate natural gas pipelines from giving an undue preference to any of their energy affiliates and to ensure that transmission is provided on a nondiscriminatory basis. In addition, unlike the prior regulations, these requirements apply even if the energy affiliate is not a customer of its affiliated interstate pipeline. Our interstate natural gas pipelines are in compliance with these Standards of Conduct.

On November 17, 2006, the United States Court of Appeals for the District of Columbia Circuit vacated Order No. 2004, as applied to natural gas pipelines, and remanded the Order back to the FERC. On January 9, 2007, the FERC issued an interim rule regarding standards of conduct in Order 690 to be effective immediately. The interim rule repromulgated the standards of conduct that were not challenged before the court. On January 18, 2007, the FERC issued a notice of proposed rulemaking soliciting comments on whether or not the interim rule should be made permanent for natural gas transmission providers.

Please refer to Note 17 to our consolidated financial statements included elsewhere in this report for additional information regarding FERC Order No. 2004 and other Standards of Conduct rulemaking.

On August 8, 2005, Congress enacted the Energy Policy Act of 2005. The Energy Policy Act, among other things, amended the Natural Gas Act to prohibit market manipulation by any entity, directed the FERC to facilitate market transparency in the market for sale or transportation of physical natural gas in interstate commerce, and significantly increased the penalties for violations of the Natural Gas Act, the Natural Gas Policy Act of 1978, or FERC rules, regulations or orders thereunder.

California Public Utilities Commission Rate Regulation

The intrastate common carrier operations of our Pacific operations’ pipelines in California are subject to regulation by the California Public Utilities Commission, referred to in this report as the CPUC, under a "depreciated book plant" methodology, which is based on an original cost measure of investment. Intrastate tariffs filed by us with the CPUC have been established on the basis of revenues, expenses and investments allocated as applicable to the California intrastate portion of our Pacific operations’ business. Tariff rates with respect to intrastate pipeline service in California are subject to challenge by complaint by interested parties or by independent action of the CPUC. A variety of factors can affect the rates of return permitted by the CPUC, and certain other issues similar to those which have arisen with respect to our FERC regulated rates could also arise with respect to our intrastate rates. Certain of our Pacific operations' pipeline rates have been, and continue to be, subject to complaints with the CPUC, as is more fully described in Note 16 to our consolidated financial statements included elsewhere in this report.

Texas Railroad Commission Rate Regulation

The intrastate common carrier operations of our natural gas and crude oil pipelines in Texas are subject to certain regulation with respect to such intrastate transportation by the Texas Railroad Commission. Although the Texas Railroad Commission has the authority to regulate our rates, the Commission has generally not investigated the rates or practices of our intrastate pipelines in the absence of shipper complaints.

Safety Regulation

Our interstate pipelines are subject to regulation by the United States Department of Transportation, referred to in this report as U.S. DOT, and our intrastate pipelines and other operations are subject to comparable state regulations with respect to their design, installation, testing, construction, operation, replacement and management. Comparable regulation exists in some states in which we conduct pipeline operations. In addition, our truck and terminal loading facilities are subject to U.S. DOT regulations dealing with the transportation of hazardous materials by motor vehicles and railcars. We believe that we are in substantial compliance with U.S. DOT and comparable state regulations.

The Pipeline Safety Improvement Act of 2002 provides guidelines in the areas of testing, education, training and communication. The Pipeline Safety Act requires pipeline companies to perform integrity tests on natural gas transmission pipelines that exist in high population density areas that are designated as High Consequence Areas. Testing consists of hydrostatic testing, internal magnetic flux or ultrasonic testing, or direct assessment of the piping. In addition to the pipeline integrity tests, pipeline companies must implement a qualification program to make certain that employees are properly trained. The U.S. DOT has approved our qualification program. We believe that we are in substantial compliance with this law's requirements and have integrated appropriate aspects of this pipeline safety law into our internal Operator Qualification Program. A similar integrity management rule for refined petroleum products pipelines became effective May 29, 2001.

We are also subject to the requirements of the Federal Occupational Safety and Health Act and other comparable federal and state statutes. We believe that we are in substantial compliance with Federal OSHA requirements, including general industry standards, recordkeeping requirements and monitoring of occupational exposure to hazardous substances.

In general, we expect to increase expenditures in the future to comply with higher industry and regulatory safety standards. Some of these changes, such as U.S. DOT implementation of additional hydrostatic testing requirements, could significantly increase the amount of these expenditures. Such increases in our expenditures cannot be accurately estimated at this time.

State and Local Regulation

Our activities are subject to various state and local laws and regulations, as well as orders of regulatory bodies, governing a wide variety of matters, including marketing, production, pricing, pollution, protection of the environment, and safety.

Environmental Matters

Our operations are subject to federal, state and local, and some foreign laws and regulations governing the release of regulated materials into the environment or otherwise relating to environmental protection or human health or safety. We believe that our operations are in substantial compliance with applicable environmental laws and regulations.

We accrue liabilities for environmental matters when it is probable that obligations have been incurred and the amounts can be reasonably estimated. This policy applies to assets or businesses currently owned or previously disposed. We have accrued liabilities for probable environmental remediation obligations at various sites, including multiparty sites where the U.S. Environmental Protection Agency has identified us as one of the potentially responsible parties. The involvement of other financially responsible companies at these multiparty sites could mitigate our actual joint and several liability exposures. Although no assurance can be given, we believe that the ultimate resolution of all these environmental matters will not have a material adverse effect on our business, financial position or results of operations. We have accrued an environmental reserve in the amount of $92.0 million as of December 31, 2007. Our reserve estimates range in value from approximately $92.0 million to approximately $142.7 million, and we recorded our liability equal to the low end of the range, as we did not identify any amounts within the range as a better estimate of the liability. For additional information related to environmental matters, see Note 16 to our consolidated financial statements included elsewhere in this report.

Solid Waste

We generate both hazardous and non-hazardous solid wastes that are subject to the requirements of the Federal Resource Conservation and Recovery Act and comparable state statutes. From time to time, state regulators and the United States Environmental Protection Agency consider the adoption of stricter disposal standards for non-hazardous waste. Furthermore, it is possible that some wastes that are currently classified as non-hazardous, which could include wastes currently generated during pipeline or liquids or bulk terminal operations, may in the future be designated as "hazardous wastes." Hazardous wastes are subject to more rigorous and costly disposal requirements than non-hazardous wastes. Such changes in the regulations may result in additional capital expenditures or operating expenses for us.

Superfund

The Comprehensive Environmental Response, Compensation and Liability Act, also known as the "Superfund" law or "CERCLA," and analogous state laws, impose joint and several liability, without regard to fault or the legality of the original conduct, on certain classes of "potentially responsible persons" for releases of "hazardous substances" into the environment. These persons include the owner or operator of a site and companies that disposed or arranged for the disposal of the hazardous substances found at the site. CERCLA authorizes the U.S. EPA and, in some cases, third parties to take actions in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur, in addition to compensation for natural resource damages, if any. Although "petroleum" is excluded from CERCLA’s definition of a "hazardous substance," in the course of our ordinary operations, we have and will generate materials that may fall within the definition of "hazardous substance." By operation of law, if we are determined to be a potentially responsible person, we may be responsible under CERCLA for all or part of the costs required to clean up sites at which such materials are present, in addition to compensation for natural resource damages, if any.

Clean Air Act

Our operations are subject to the Clean Air Act, as amended, and analogous state statutes. We believe that the operations of our pipelines, storage facilities and terminals are in substantial compliance with such statutes. The Clean Air Act, as amended, contains lengthy, complex provisions that may result in the imposition over the next several years of certain pollution control requirements with respect to air emissions from the operations of our pipelines, treating facilities, storage facilities and terminals. Depending on the nature of those requirements and any additional requirements that may be imposed by state and local regulatory authorities, we may be required to incur certain capital and operating expenditures over the next several years for air pollution control equipment in connection with maintaining or obtaining operating permits and approvals and addressing other air emission-related issues.

Due to the broad scope and complexity of the issues involved and the resultant complexity and nature of the regulations, full development and implementation of many Clean Air Act regulations by the U.S. EPA and/or various state and local regulators have been delayed. Therefore, until such time as the new Clean Air Act requirements are implemented, we are unable to fully estimate the effect on earnings or operations or the amount and timing of such required capital expenditures. At this time, however, we do not believe that we will be materially adversely affected by any such requirements.

Clean Water Act

Our operations can result in the discharge of pollutants. The Federal Water Pollution Control Act of 1972, as amended, also known as the Clean Water Act, and analogous state laws impose restrictions and controls regarding the discharge of pollutants into state waters or waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by applicable federal or state authorities. The Oil Pollution Act was enacted in 1990 and amends provisions of the Clean Water Act as they pertain to prevention and response to oil spills. Spill prevention control and countermeasure requirements of the Clean Water Act and some state laws require containment and similar structures to help prevent contamination of navigable waters in the event of an overflow or release. We believe we are in substantial compliance with these laws.

Other

KMGP Services Company, Inc., Knight and Kinder Morgan Canada Inc. employ all persons necessary for the operation of our business. Generally, we reimburse these entities for the services of their employees. As of December 31, 2007, KMGP Services Company, Inc., Knight and Kinder Morgan Canada Inc. had, in the aggregate, approximately 7,600 full-time employees. Approximately 920 full-time hourly personnel at certain terminals and pipelines are represented by labor unions under collective bargaining agreements that expire between 2008 and 2012. KMGP Services Company, Inc., Knight and Kinder Morgan Canada Inc. each consider relations with their employees to be good. For more information on our related party transactions, see Note 12 of the notes to our consolidated financial statements included elsewhere in this report.

We believe that we have generally satisfactory title to the properties we own and use in our businesses, subject to liens for current taxes, liens incident to minor encumbrances, and easements and restrictions, which do not materially detract from the value of such property or the interests in those properties or the use of such properties in our businesses. We generally do not own the land on which our pipelines are constructed. Instead, we obtain the right to construct and operate the pipelines on other people’s land for a period of time. Substantially all of our pipelines are constructed on rights-of-way granted by the apparent record owners of such property. In many instances, lands over which rights-of-way have been obtained are subject to prior liens, which have not been subordinated to the right-of-way grants. In some cases, not all of the apparent record owners have joined in the right-of-way grants, but in substantially all such cases, signatures of the owners of majority interests have been obtained. Permits have been obtained from public authorities to cross over or under, or to lay facilities in or along, water courses, county roads, municipal streets and state highways, and in some instances, such permits are revocable at the election of the grantor, or, the pipeline may be required to move its facilities at its own expense. Permits have also been obtained from railroad companies to cross over or under lands or rights-of-way, many of which are also revocable at the grantor's election. Some such permits require annual or other periodic payments. In a few minor cases, property for pipeline purposes was purchased in fee.

(d) Financial Information about Geographic Areas

For geographic information concerning our assets and operations, see Note 15 to our consolidated financial statements.

(e) Available Information

We make available free of charge on or through our Internet website, at www.kindermorgan.com, our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after we electronically file such material with, or furnish it to, the Securities and Exchange Commission.

Item 1A. *Risk Factors*.

You should carefully consider the risks described below, in addition to the other information contained in this document. Realization of any of the following risks could have a material adverse effect on our business, financial condition, cash flows and results of operations. There are also risks associated with being an owner of common units in a partnership that are different than being an owner of common stock in a corporation. Investors in our common units must be aware that the realization of any of those risks could result in a decline in the trading price of our common units, and they might lose all or part of their investment.

Risks Related to Our Business

Pending Federal Energy Regulatory Commission and California Public Utilities Commission proceedings seek substantial refunds and reductions in tariff rates on some of our pipelines. If the proceedings are determined adversely to us, they could have a material adverse impact on us.

Regulators and shippers on our pipelines have rights to challenge the rates we charge under certain circumstances prescribed by applicable regulations. Some shippers on our pipelines have filed complaints with the Federal Energy Regulatory Commission and California Public Utilities Commission that seek substantial refunds for alleged overcharges during the years in question and prospective reductions in the tariff rates on our Pacific operations' pipeline system. We may face challenges, similar to those described in Note 16 to our consolidated financial statements included elsewhere in this report, to the rates we receive on our pipelines in the future. Any successful challenge could adversely and materially affect our future earnings and cash flows.

Rulemaking and oversight, as well as changes in regulations, by the Federal Energy Regulatory Commission or other regulatory agencies having jurisdiction over our operations could adversely impact our income and operations.

The rates (which include reservation, commodity, surcharges, fuel and gas lost and unaccounted for) we charge shippers on our natural gas pipeline systems are subject to regulatory approval and oversight. Furthermore, regulators and shippers on our natural gas pipelines have rights to challenge the rates shippers are charged under certain circumstances prescribed by applicable regulations. We can provide no assurance that we will not face challenges to the rates we receive on our pipeline systems in the future. Any successful challenge could materially adversely affect our future earnings and cash flows. New laws or regulations or different interpretations of existing laws or regulations applicable to our assets could have a material adverse impact on our business, financial condition and results of operations.

Increased regulatory requirements relating to the integrity of our pipelines will require us to spend additional money to comply with these requirements.

Through our regulated pipeline subsidiaries, we are subject to extensive laws and regulations related to pipeline integrity. There are, for example, federal guidelines for the U.S. Department of Transportation and pipeline companies in the areas of testing, education, training and communication. Compliance with laws and regulations requires significant expenditures. We have increased our capital expenditures to address these matters and expect to significantly increase these expenditures in the foreseeable future. Additional laws and regulations that may be enacted in the future or a new interpretation of existing laws and regulations could significantly increase the amount of these expenditures.

Cost overruns and delays on our expansion and new build projects could adversely affect our business.

We currently have several major expansion and new build projects planned or underway, including the approximate $4.9 billion Rockies Express Pipeline and the approximate $1.3 billion Midcontinent Express Pipeline. A variety of factors outside our control, such as weather, natural disasters and difficulties in obtaining permits and rights-of-way or other regulatory approvals, as well as the performance by third party contractors has resulted in, and may continue to result in, increased costs or delays in construction. Cost overruns or delays in completing a project could have a material adverse effect on our results of operations and cash flows.

Our rapid growth may cause difficulties integrating and constructing new operations, and we may not be able to achieve the expected benefits from any future acquisitions.

Part of our business strategy includes acquiring additional businesses, expanding existing assets, or constructing new facilities that will allow us to increase distributions to our unitholders. If we do not successfully integrate acquisitions, expansions, or newly constructed facilities, we may not realize anticipated operating advantages and cost savings. The integration of companies that have previously operated separately involves a number of risks, including:

- demands on management related to the increase in our size after an acquisition, an expansion, or a completed construction project;
- the diversion of our management's attention from the management of daily operations;
- difficulties in implementing or unanticipated costs of accounting, estimating, reporting and other systems;
- difficulties in the assimilation and retention of necessary employees; and
- potential adverse effects on operating results.

We may not be able to maintain the levels of operating efficiency that acquired companies have achieved or might achieve separately. Successful integration of each acquisition, expansion, or construction project will depend upon our ability to manage those operations and to eliminate redundant and excess costs. Because of difficulties in combining and expanding operations, we may not be able to achieve the cost savings and other size-related benefits that we hoped to achieve after these acquisitions, which would harm our financial condition and results of operations.

Our acquisition strategy and expansion programs require access to new capital. Tightened credit markets or more expensive capital would impair our ability to grow.

Part of our business strategy includes acquiring additional businesses. We may need new capital to finance these acquisitions. Limitations on our access to capital will impair our ability to execute this strategy. We normally fund acquisitions with short-term debt and repay such debt through the issuance of equity and long-term debt. An inability to access the capital markets may result in a substantial increase in our leverage and have a detrimental impact on our credit profile.

Environmental regulation and liabilities could result in increased operating and capital costs.

Our business operations are subject to federal, state, provincial and local laws and regulations relating to environmental protection, pollution and human health and safety in the United States and Canada. For example, if an accidental leak, release or spill of liquid petroleum products, chemicals or other products occurs at or from our pipelines or at or from our storage or other facilities, we may experience significant operational disruptions and we may have to pay a significant amount to clean up the leak, release or spill, pay for government penalties, address natural resource damage, compensate for human exposure or property damage, install costly pollution control equipment or a combination of these and other measures. The resulting costs and liabilities could materially and negatively affect our level of earnings and cash flows. In addition, emission controls required under federal, state and provincial environmental laws could require significant capital expenditures at our facilities. The costs of environmental regulation are already significant, and additional or more stringent regulation could increase these costs or could otherwise negatively affect our business.

In addition, our oil and gas development and production activities are subject to certain federal, state and local laws and regulations relating to environmental quality and pollution control. These laws and regulations increase the costs of these activities and may prevent or delay the commencement or continuance of a given operation. Specifically, we are subject to laws and regulations regarding the acquisition of permits before drilling, restrictions on drilling activities in restricted areas, emissions into the environment, water discharges, and storage and disposition of hazardous wastes. In addition, legislation has been enacted which requires well and facility sites to be abandoned and reclaimed to the satisfaction of state authorities. The costs of environmental regulation are already significant, and additional or more stringent regulation could increase these costs or could otherwise negatively affect our business.

Energy commodity transportation and storage activities involve numerous risks that may result in accidents or otherwise adversely affect operations.

There are a variety of hazards and operating risks inherent to natural gas transmission and storage activities, and refined petroleum products and carbon dioxide transportation activities—such as leaks, explosions and mechanical problems that could result in substantial financial losses. In addition, these risks could result in loss of human life, significant damage to property, environmental pollution and impairment of operations, any of which also could result in substantial losses. For pipeline and storage assets located near populated areas, including residential areas, commercial business centers, industrial sites and other public gathering areas, the level of damage resulting from these risks could be greater. If losses in excess of our insurance coverage were to occur, they could have a material adverse effect on our business, financial condition and results of operations.

The future success of our oil and gas development and production operations depends in part upon our ability to develop additional oil and gas reserves that are economically recoverable.

The rate of production from oil and natural gas properties declines as reserves are depleted. Without successful development activities, the reserves and revenues of our oil producing assets within our CO_2 business segment will decline. We may not be able to develop or acquire additional reserves at an acceptable cost or have necessary financing for these activities in the future. Additionally, if we do not realize production volumes greater than, or equal to, our hedged volumes, we will be liable to perform on hedges currently valued at greater than $1.3 billion in favor of our counter-parties.

The development of oil and gas properties involves risks that may result in a total loss of investment.

The business of developing and operating oil and gas properties involves a high degree of business and financial risk that even a combination of experience, knowledge and careful evaluation may not be able to overcome. Acquisition and development decisions generally are based on subjective judgments and assumptions that, while they may be reasonable, are by their nature speculative. It is impossible to predict with certainty the production potential of a particular property or well. Furthermore, a successful completion of a well does not ensure a profitable return on the investment. A variety of geological, operational, or market-related factors, including, but not limited to, unusual or unexpected geological formations, pressures, equipment failures or accidents, fires, explosions, blowouts, cratering, pollution and other environmental risks, shortages or delays in the availability of drilling rigs and the delivery of equipment, loss of circulation of drilling fluids or other conditions may substantially delay or prevent completion of any well, or otherwise prevent a property or well from being profitable. A productive well may become uneconomic in the event water or other deleterious substances are encountered, which impair or prevent the production of oil and/or gas from the well. In addition, production from any well may be unmarketable if it is contaminated with water or other deleterious substances.

The volatility of natural gas and oil prices could have a material adverse effect on our business.

The revenues, profitability and future growth of our CO_2 business segment and the carrying value of our oil and natural gas properties depend to a large degree on prevailing oil and gas prices. Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply and demand for oil and natural gas, uncertainties within the market and a variety of other factors beyond our control. These factors include, among other things, weather conditions and events such as hurricanes in the United States; the condition of the United States economy; the activities of the Organization of Petroleum Exporting Countries; governmental regulation; political stability in the Middle East and elsewhere; the foreign supply of oil and natural gas; the price of foreign imports; and the availability of alternative fuel sources.

A sharp decline in the price of natural gas or oil prices would result in a commensurate reduction in our revenues, income and cash flows from the production of oil and natural gas and could have a material adverse effect on the carrying value of our proved reserves. In the event prices fall substantially, we may not be able to realize a profit from our production and would operate at a loss. In recent decades, there have been periods of both worldwide overproduction and underproduction of hydrocarbons and periods of both increased and relaxed energy conservation efforts. Such conditions have resulted in periods of excess supply of, and reduced demand for, crude oil on a worldwide basis and for natural gas on a domestic basis. These periods have been followed by periods of short supply of, and increased demand for, crude oil and natural gas. The excess or short supply of crude oil or natural gas has placed pressures on prices and has resulted in dramatic price fluctuations even during relatively short periods of seasonal market demand.

Our use of hedging arrangements could result in financial losses or reduce our income.

We currently engage in hedging arrangements to reduce our exposure to fluctuations in the prices of oil and natural gas. These hedging arrangements expose us to risk of financial loss in some circumstances, including when production is less than expected, when the counterparty to the hedging contract defaults on its contract obligations, or when there is a change in the expected differential between the underlying price in the hedging agreement and the actual prices received. In addition, these hedging arrangements may limit the benefit we would otherwise receive from increases in prices for oil and natural gas.

The accounting standards regarding hedge accounting are complex, and even when we engage in hedging transactions (for example, to mitigate our exposure to fluctuations in commodity prices or to balance our exposure to fixed and floating interest rates) that are effective economically, these transactions may not be considered effective for accounting purposes. Accordingly, our financial statements may reflect some volatility due to these hedges, even when there is no underlying economic impact at that point. In addition, it is not always possible for us to engage in a hedging transaction that completely mitigates our exposure to commodity prices. Our financial statements may reflect a gain or loss arising from an exposure to commodity prices for which we are unable to enter into a completely effective hedge.

We do not own approximately 97.5% of the land on which our pipelines are constructed, and we are subject to the possibility of increased costs to retain necessary land use.

We obtain the right to construct and operate pipelines on other owners' land for a period of time. If we were to lose these rights or be required to relocate our pipelines, our business could be affected negatively.

Whether we have the power of eminent domain for our pipelines varies from state to state depending upon the type of pipeline—petroleum liquids, natural gas or carbon dioxide—and the laws of the particular state. Our inability to exercise the power of eminent domain could negatively affect our business if we were to lose the right to use or occupy the property on which our pipelines are located. For the year ended December 31, 2007, all of our right-of-way related expenses totaled $14.6 million.

Our debt instruments may limit our financial flexibility and increase our financing costs.

The instruments governing our debt contain restrictive covenants that may prevent us from engaging in certain transactions that we deem beneficial and that may be beneficial to us. The agreements governing our debt generally require us to comply with various affirmative and negative covenants, including the maintenance of certain financial ratios and restrictions on (i) incurring additional debt; (ii) entering into mergers, consolidations and sales of assets; (iii) granting liens; and (iv) entering into sale-leaseback transactions. The instruments governing any future debt may contain similar or more restrictive restrictions. Our ability to respond to changes in business and economic conditions and to obtain additional financing, if needed, may be restricted.

Because a portion of our debt is subject to variable interest rates, if interest rates increase, our earnings could be adversely affected.

As of December 31, 2007, we had approximately $3.0 billion of debt, excluding the value of interest rate swaps, subject to variable interest rates. This amount included $2.3 billion of long-term fixed rate debt effectively converted to variable rate debt through the use of interest rate swaps. Should interest rates increase significantly, our earnings could be adversely affected. For information on our interest rate risk, see Item 7A "Quantitative and Qualitative Disclosures About Market Risk—Interest Rate Risk."

Current or future distressed financial conditions of customers could have an adverse impact on us in the event these customers are unable to pay us for the services we provide.

Some of our customers are experiencing, or may experience in the future, severe financial problems that have had or may have a significant impact on their creditworthiness. We cannot provide assurance that one or more of our financially distressed customers will not default on their obligations to us or that such a default or defaults will not have a material adverse effect on our business, financial position, future results of operations, or future cash flows. Furthermore, the bankruptcy of one or more of our customers, or some other similar proceeding or liquidity constraint, might make it unlikely that we would be able to collect all or a significant portion of amounts owed by the distressed entity or entities. In addition, such events might force such customers to reduce or curtail their future use of our products and services, which could have a material adverse effect on our results of operations and financial condition.

The general uncertainty associated with the current world economic and political environments in which we exist may adversely impact our financial performance.

Our financial performance is impacted by overall marketplace spending and demand. We are continuing to assess the effect that terrorism would have on our businesses and in response, we have increased security with respect to our assets. Recent federal legislation provides an insurance framework that should cause current insurers to continue to provide sabotage and terrorism coverage under standard property insurance policies. Nonetheless, there is no assurance that adequate sabotage and terrorism insurance will be available at rates we believe are reasonable throughout 2008.

Knight’s recently completed going-private transaction resulted in substantially more debt at Knight and could have an adverse effect on us, such as a downgrade in the ratings of our debt securities.

On May 30, 2007, Knight completed its going-private transaction. In connection with the transaction, Knight incurred substantially more debt. In conjunction with the going-private transaction, Moody’s Investor Service, Inc. and Standard & Poor’s Rating Services reviewed and adjusted the credit ratings of both Knight and us. Following these adjustments, our senior unsecured debt is rated BBB and Baa2 by Standard & Poor’s and Moody’s, respectively. Though steps have been taken which are intended to allow our senior unsecured indebtedness to continue to be rated investment grade, we can provide no assurance that that will be the case. Additionally, our rating was downgraded by Fitch Ratings from BBB+ to BBB on April 11, 2007.

Our senior management’s attention may be diverted from our daily operations because of recent significant transactions by Knight following the completion of the going-private transaction.

The investors in Knight Holdco LLC include members of Knight’s senior management, most of whom are also senior officers of our general partner and of KMR. Prior to consummation of the going-private transaction, KMI had publicly disclosed that several significant transactions were being considered that, if pursued, would require substantial management time and attention. As a result, our senior management’s attention may be diverted from the management of our daily operations.

Competition could ultimately lead to lower levels of profits and adversely impact our ability to recontract for expiring transportation capacity at favorable rates.

Trans Mountain’s pipeline to the West Coast of North America is one of several pipeline alternatives for Western Canadian petroleum production. This pipeline, like all our petroleum pipelines, competes against other pipeline companies who could be in a position to offer different tolling structures, which may provide them with a competitive advantage in new pipeline development. Throughput on our pipelines may decline if tolls become uncompetitive compared to alternatives.

Future business development of our products pipelines is dependent on the supply of, and demand for, crude oil and other liquid hydrocarbons, particularly from the Alberta oilsands.

Our pipelines depend on production of natural gas, oil and other products in the areas serviced by our pipelines. Without reserve additions, production will decline over time as reserves are depleted and production costs may rise. Producers may shut down production at lower product prices or higher production costs, especially where the existing cost of production exceeds other extraction methodologies, such as at the Alberta oilsands. Producers in areas serviced by us may not be successful in exploring for and developing additional reserves, and the gas plants and the pipelines may not be able to maintain existing volumes of throughput. Commodity prices and tax incentives may not remain at a level which encourages producers to explore for and develop additional reserves, produce existing marginal reserves or renew transportation contracts as they expire.

Changes in the business environment, such as a decline in crude oil prices, an increase in production costs from higher feedstock prices, supply disruptions, or higher development costs, could result in a slowing of supply from the Alberta oilsands. In addition, changes in the regulatory environment or governmental policies may have an impact on the supply of crude oil. Each of these factors impact our customers shipping through our pipelines, which in turn could impact the prospects of new transportation contracts or renewals of existing contracts.

Throughput on our products pipelines may also decline as a result of changes in business conditions. Over the long term, business will depend, in part, on the level of demand for oil and natural gas in the geographic areas in which deliveries are made by pipelines and the ability and willingness of shippers having access or rights to utilize the pipelines to supply such demand. The implementation of new regulations or the modification of existing regulations affecting the oil and gas industry could reduce demand for natural gas and crude oil, increase our costs and may have a material adverse effect on our results of operations and financial condition. We cannot predict the impact of future economic conditions, fuel conservation measures, alternative fuel requirements, governmental regulation or technological advances in fuel economy and energy generation devices, all of which could reduce the demand for natural gas and oil.

We are subject to U.S. dollar/Canadian dollar exchange rate fluctuations.

As a result of our acquisition of the Trans Mountain pipeline system, the Vancouver Wharves terminal, the Cochin pipeline system, and our terminal expansion projects located in Edmonton, Alberta, Canada, a portion of our assets, liabilities, revenues and expenses are denominated in Canadian dollars. We are a U.S. dollar reporting company. Fluctuations in the exchange rate between United States and Canadian dollars could expose us to reductions in the U.S. dollar value of our earnings and cash flows and a reduction in our partners' capital under applicable accounting rules.

Risks Related to Our Common Units

The interests of Knight may differ from our interests and the interests of our unitholders.

Knight indirectly owns all of the stock of our general partner and elects all of its directors. Our general partner owns all of KMR's voting shares and elects all of its directors. Furthermore, some of KMR's directors and officers are also directors and officers of Knight and our general partner and have fiduciary duties to manage the businesses of Knight in a manner that may not be in the best interests of our unitholders. Knight has a number of interests that differ from the interests of our unitholders. As a result, there is a risk that important business decisions will not be made in the best interests of our unitholders.

Common unitholders have limited voting rights and limited control.

Holders of common units have only limited voting rights on matters affecting us. Our general partner manages partnership activities. Under a delegation of control agreement, our general partner has delegated the management and control of our and our subsidiaries' business and affairs to KMR. Holders of common units have no right to elect the general partner on an annual or other ongoing basis. If the general partner withdraws, however, its successor may be elected by the holders of a majority of the outstanding common units (excluding units owned by the departing general partner and its affiliates).

The limited partners may remove the general partner only if (i) the holders of at least 66 2/3% of the outstanding common units, excluding common units owned by the departing general partner and its affiliates, vote to remove the general partner; (ii) a successor general partner is approved by at least 66 2/3% of the outstanding common units, excluding common units owned by the departing general partner and its affiliates; and (iii) we receive an opinion of counsel opining that the removal would not result in the loss of limited liability to any limited partner, or the limited partner of an operating partnership, or cause us or the operating partnership to be taxed other than as a partnership for federal income tax purposes.

A person or group owning 20% or more of the common units cannot vote.

Any common units held by a person or group that owns 20% or more of the common units cannot be voted. This limitation does not apply to the general partner and its affiliates. This provision may (i) discourage a person or group from attempting to remove the general partner or otherwise change management; and (ii) reduce the price at which the common units will trade under certain circumstances. For example, a third party will probably not attempt to take over our management by making a tender offer for the common units at a price above their trading market price without removing the general partner and substituting an affiliate of its own.

The general partner's liability to us and our unitholders may be limited.

Our partnership agreement contains language limiting the liability of the general partner to us or the holders of common units. For example, our partnership agreement provides that (i) the general partner does not breach any duty to us or the holders of common units by borrowing funds or approving any borrowing (the general partner is protected even if the purpose or effect of the borrowing is to increase incentive distributions to the general partner); (ii) the general partner does not breach any duty to us or the holders of common units by taking any actions consistent with the standards of reasonable discretion outlined in the definitions of available cash and cash from operations contained in our partnership agreement; and (iii) the general partner does not breach any standard of care or duty by resolving conflicts of interest unless the general partner acts in bad faith.

Unitholders may have liability to repay distributions.

Unitholders will not be liable for assessments in addition to their initial capital investment in the common units. Under certain circumstances, however, holders of common units may have to repay us amounts wrongfully returned or distributed to them. Under Delaware law, we may not make a distribution to unitholders if the distribution causes our liabilities to exceed the fair value of our assets. Liabilities to partners on account of their partnership interests and non-recourse liabilities are not counted for purposes of determining whether a distribution is permitted. Delaware law provides that for a period of three years from the date of such a distribution, a limited partner who receives the distribution and knew at the time of the distribution that the distribution violated Delaware law will be liable to the limited partnership for the distribution amount. Under Delaware law, an assignee who becomes a substituted limited partner of a limited partnership is liable for the obligations of the assignor to make contributions to the partnership. However, such an assignee is not obligated for liabilities unknown to the assignee at the time the assignee became a limited partner if the liabilities could not be determined from the partnership agreement.

Unitholders may be liable if we have not complied with state partnership law.

We conduct our business in a number of states. In some of those states the limitations on the liability of limited partners for the obligations of a limited partnership have not been clearly established. The unitholders might be held liable for the partnership's obligations as if they were a general partner if (i) a court or government agency determined that we were conducting business in the state but had not complied with the state's partnership statute; or (ii) unitholders' rights to act together to remove or replace the general partner or take other actions under our partnership agreement constitute "control" of our business.

The general partner may buy out minority unitholders if it owns 80% of the units.

If at any time the general partner and its affiliates own 80% or more of the issued and outstanding common units, the general partner will have the right to purchase all, and only all, of the remaining common units. Because of this right, a unitholder could have to sell its common units at a time or price that may be undesirable. The purchase price for such a purchase will be the greater of (i) the 20-day average trading price for the common units as of the date five days prior to the date the notice of purchase is mailed; or (ii) the highest purchase price paid by the general partner or its affiliates to acquire common units during the prior 90 days. The general partner can assign this right to its affiliates or to us.

We may sell additional limited partner interests, diluting existing interests of unitholders.

Our partnership agreement allows the general partner to cause us to issue additional common units and other equity securities. When we issue additional equity securities, including additional i-units to KMR when it issues additional shares, unitholders' proportionate partnership interest in us will decrease. Such an issuance could negatively affect the amount of cash distributed to unitholders and the market price of common units. Issuance of additional common units will also diminish the relative voting strength of the previously outstanding common units. Our partnership agreement does not limit the total number of common units or other equity securities we may issue.

The general partner can protect itself against dilution.

Whenever we issue equity securities to any person other than the general partner and its affiliates, the general partner has the right to purchase additional limited partnership interests on the same terms. This allows the general partner to maintain its proportionate partnership interest in us. No other unitholder has a similar right. Therefore, only the general partner may protect itself against dilution caused by issuance of additional equity securities.

Our partnership agreement and the KMR limited liability company agreement restrict or eliminate a number of the fiduciary duties that would otherwise be owed by our general partner and/or its delegate to our unitholders.

Modifications of state law standards of fiduciary duties may significantly limit the ability of our unitholders to successfully challenge the actions of our general partner in the event of a breach of fiduciary duties. These state law standards include the duties of care and loyalty. The duty of loyalty, in the absence of a provision in the limited partnership agreement to the contrary, would generally prohibit our general partner from taking any action or engaging in any transaction as to which it has a conflict of interest. Our limited partnership agreement contains provisions that prohibit limited partners from advancing claims that otherwise might raise issues as to compliance with fiduciary duties or applicable law. For example, that agreement provides that the general partner may take into account the interests of parties other than us in resolving conflicts of interest. It also provides that in the absence of bad faith by the general partner, the resolution of a conflict by the general partner will not be a breach of any duty. The provisions relating to the general partner apply equally to KMR as its delegate. It is not necessary for a limited partner to sign our limited partnership agreement in order for the limited partnership agreement to be enforceable against that person.

We adopted certain valuation methodologies that may result in a shift of income, gain, loss and deduction between our general partner and our unitholders. The IRS may challenge this treatment, which could adversely affect the value of the common units.

When we issue additional units or engage in certain other transactions, we determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our general partner. This methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and our general partner, which may be unfavorable to such unitholders. Moreover, under our current valuation methods, subsequent purchasers of common units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge these valuation methods, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between our general partner and certain of our unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our partners. It also could affect the amount of gain from our unitholders' sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

Our treatment of a purchaser of common units as having the same tax benefits as the seller could be challenged, resulting in a reduction in value of the common units.

Because we cannot match transferors and transferees of common units, we are required to maintain the uniformity of the economic and tax characteristics of these units in the hands of the purchasers and sellers of these units. We do so by adopting certain depreciation conventions that do not conform to all aspects of the United States Treasury regulations. A successful IRS challenge to these conventions could adversely affect the tax benefits to a unitholder of ownership of the common units and could have a negative impact on their value or result in audit adjustments to unitholders' tax returns.

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the Internal Revenue Service treats us as a corporation or if we become subject to a material amount of entity-level taxation for state tax purposes, it would substantially reduce the amount of cash available for distribution to our partners.

The anticipated after-tax economic benefit of an investment in us depends largely on our being treated as a partnership for federal income tax purposes. In order for us to be treated as a partnership for federal income tax purposes, current law requires that 90% or more of our gross income for every taxable year consist of "qualifying income," as defined in Section 7704 of the Internal Revenue Code. We may not meet this requirement or current law may change so as to cause, in either event, us to be treated as a corporation for federal income tax purposes or otherwise subject to federal income tax. We have not requested, and do not plan to request, a ruling from the Internal Revenue Service on this or any other matter affecting us.

If we were to be treated as a corporation for federal income tax purposes, we would pay federal income tax on our income at the corporate tax rate, which is currently a maximum of 35%, and would pay state income taxes at varying rates. Under current law, distributions to our partners would generally be taxed again as corporate distributions, and no income, gain, losses or deductions would flow through to our partners. Because a tax would be imposed on us as a corporation, our cash available for distribution would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to our partners, likely causing substantial reduction in the value of our units.

Current law or our business may change so as to cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. Members of Congress are considering substantive changes to the existing federal income tax laws that affect certain publicly-traded partnerships. For example, federal income tax legislation has been proposed that would eliminate partnership tax treatment for certain publicly-traded partnerships. Although the currently proposed legislation would not appear to affect our tax treatment as a partnership, we are unable to predict whether any of these changes, or other proposals, will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units.

In addition, because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise or other forms of taxation. For example, we are now subject to a new entity-level tax on the portion of our total revenue that is generated in Texas. Specifically, the Texas margin tax is imposed at a maximum effective rate of 0.7% of our total revenue that is apportioned to Texas. Imposition of such a tax on us by Texas, or any other state, will reduce our cash available for distribution to our partners.

Our partnership agreement provides that if a law is enacted that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal income tax purposes, the minimum quarterly distribution and the target distribution levels will be adjusted to reflect the impact on us of that law.

The issuance of additional i-units may cause more taxable income to be allocated to the common units.

The i-units we issue to KMR generally are not allocated income, gain, loss or deduction for federal income tax purposes until such time as we are liquidated. Therefore, the issuance of additional i-units may cause more taxable income and gain to be allocated to the common unitholders.

Risks Related to Ownership of Our Common Units if We or Knight Defaults on Debt

Unitholders may have negative tax consequences if we default on our debt or sell assets.

If we default on any of our debt, the lenders will have the right to sue us for non-payment. Such an action could cause an investment loss and cause negative tax consequences for unitholders through the realization of taxable income by unitholders without a corresponding cash distribution. Likewise, if we were to dispose of assets and realize a taxable gain while there is substantial debt outstanding and proceeds of the sale were applied to the debt, unitholders could have increased taxable income without a corresponding cash distribution.

There is the potential for a change of control if Knight defaults on debt.

Knight owns all of the outstanding capital stock of our general partner. Knight has operations which provide cash independent of dividends that Knight receives from our general partner. Nevertheless, if Knight defaults on its debt, in exercising their rights as lenders, Knight's lenders could acquire control of our general partner or otherwise influence our general partner through control of Knight.

Item 1B. ***Unresolved Staff Comments.***

None.

Item 3. ***Legal Proceedings.***

See Note 16 of the notes to our consolidated financial statements included elsewhere in this report.

Item 4. ***Submission of Matters to a Vote of Security Holders.***

There were no matters submitted to a vote of our unitholders during the fourth quarter of 2007.

PART II

Item 5. ***Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.***

The following table sets forth, for the periods indicated, the high and low sale prices per common unit, as reported on the New York Stock Exchange, the principal market in which our common units are traded, the amount of cash distributions declared per common and Class B unit, and the fractional i-unit distribution declared per i-unit.

	Price Range			
	High	**Low**	**Cash Distributions**	**i-unit Distributions**
2007				
First Quarter	$ 53.50	$ 47.28	$ 0.8300	0.015378
Second Quarter	57.35	52.11	0.8500	0.016331
Third Quarter	56.70	46.61	0.8800	0.017686
Fourth Quarter	54.71	48.51	0.9200	0.017312
2006				
First Quarter	$ 56.22	$ 44.70	$ 0.8100	0.018566
Second Quarter	48.80	43.62	0.8100	0.018860
Third Quarter	46.53	42.80	0.8100	0.018981
Fourth Quarter	48.98	43.01	0.8300	0.016919

Distribution information is for distributions declared with respect to that quarter. The declared distributions were paid within 45 days after the end of the quarter. We currently expect to declare cash distributions of at least $4.02 per unit for 2008; however, no assurance can be given that we will be able to achieve this level of distribution, and our expectation does not take into account any capital costs associated with financing the payment of reparations sought by shippers on our Pacific operations' interstate pipelines.

As of January 31, 2008, there were approximately 190,660 holders of our common units (based on the number of record holders and individual participants in security position listings), one holder of our Class B units and one holder of our i-units.

For information on our equity compensation plans, see Item 12 "Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters—Equity Compensation Plan Information".

We did not repurchase any units during 2007 or sell any unregistered units in the fourth quarter of 2007.

Item 6. ***Selected Financial Data***

The following tables set forth, for the periods and at the dates indicated, our summary historical financial and operating data. The table is derived from our consolidated financial statements and notes thereto, and should be read in conjunction with those audited financial statements. See also Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations" in this report for more information.

	Year Ended December 31,				
	2007(6)	2006(7)	2005(8)	2004(9)	2003(10)
	(In millions, except per unit and ratio data)				
Income and Cash Flow Data:					
Revenues	$ 9,217.7	$ 9,048.7	$ 9,745.9	$ 7,893.0	$ 6,583.6
Costs, Expenses and Other:					
Gas purchases and other costs of sales	5,809.8	5,990.9	7,167.3	5,767.0	4,880.0
Operations and maintenance	1,024.6	777.0	719.5	488.6	388.6
Fuel and power	237.5	223.7	178.5	146.4	102.2
Depreciation, depletion and amortization	540.0	423.9	341.6	281.1	212.2
General and administrative	278.7	238.4	216.7	170.5	150.5
Taxes, other than income taxes	153.8	134.4	106.5	79.1	60.3
Other expense (income)	365.6	(31.2)	—	—	—
	8,410.0	7,757.1	8,730.1	6,932.7	5,793.8
Operating income	807.7	1,291.6	1,015.8	960.3	789.8
Other income/(expense):					
Earnings from equity investments	69.7	74.0	89.6	81.8	91.2
Amortization of excess cost of equity investments	(5.8)	(5.6)	(5.5)	(5.6)	(5.5)
Interest, net	(391.4)	(337.8)	(259.0)	(192.9)	(181.4)
Other, net	14.2	12.0	3.3	2.2	7.6
Minority interest	(7.0)	(15.4)	(7.3)	(9.6)	(9.0)
Income tax provision	(71.0)	(29.0)	(24.5)	(19.7)	(16.6)
Income from continuing operations	416.4	989.8	812.4	816.5	676.1
Income (loss) from discontinued operations(1)	173.9	14.3	(0.2)	15.1	17.8
Income before cumulative effect of a change in accounting principle	590.3	1,004.1	812.2	831.6	693.9
Cumulative effect of a change in accounting principle	—	—	—	—	3.4
Net income	$ 590.3	$ 1,004.1	$ 812.2	$ 831.6	$ 697.3
Less: General Partner's interest in net income	(611.6)	(513.3)	(477.3)	(395.1)	(326.5)
Limited Partners' interest in net income (loss)	$ (21.3)	$ 490.8	$ 334.9	$ 436.5	$ 370.8
Basic Limited Partners' net income (loss) per unit:					
Income (loss) per unit from continuing operations and before cumulative effect of a change in accounting principle(2)	$ (0.82)	$ 2.12	$ 1.58	$ 2.14	$ 1.89
Income from discontinued operations	0.73	0.07	—	0.08	0.09
Cumulative effect of a change in accounting principle	—	—	—	—	0.02
Net income (loss) per unit	$ (0.09)	$ 2.19	$ 1.58	$ 2.22	$ 2.00
Diluted Limited Partners' net income (loss) per unit:					
Income (loss) per unit from continuing operations and bef. cumulative effect of a change in acctg. principle(2)	$ (0.82)	$ 2.12	$ 1.58	$ 2.14	$ 1.89
Income from discontinued operations	0.73	0.06	—	0.08	0.09
Cumulative effect of a change in accounting principle	—	—	—	—	0.02
Net income (loss) per unit	$ (0.09)	$ 2.18	$ 1.58	$ 2.22	$ 2.00
Per unit cash distribution declared(3)	$ 3.48	$ 3.26	$ 3.13	$ 2.87	$ 2.63
Ratio of earnings to fixed charges(4)	$ 2.13	$ 3.64	3.76	4.84	4.68

Additions to property, plant and equipment	$	1,691.6	$	1,182.1	$	863.1	$	747.3	$	577.0
Balance Sheet Data (at end of period):										
Net property, plant and equipment	$	11,591.3	$	10,106.1	$	8,864.6	$	8,168.9	$	7,091.6
Total assets	$	15,177.8	$	13,542.2	$	11,923.5	$	10,552.9	$	9,139.2
Long-term debt(5)	$	6,455.9	$	4,384.3	$	5,220.9	$	4,722.4	$	4,316.7

(1) Represents income or loss from the operations of our North System natural gas liquids pipeline system. For 2007 only, also includes a gain of $152.8 million on disposal of our North System. For more information on our discontinued operations, see Note 3 to our consolidated financial statements included elsewhere in this report.

(2) Represents income from continuing operations before cumulative effect of a change in accounting principle per unit. Basic Limited Partners' income per unit from continuing operations before cumulative effect of a change in accounting principle was computed by dividing the interest of our unitholders in income from continuing operations before cumulative effect of a change in accounting principle by the weighted average number of units outstanding during the period. Diluted Limited Partners' net income per unit reflects the maximum potential dilution that could occur if units whose issuance depends on the market price of the units at a future date were considered outstanding, or if, by application of the treasury stock method, options to issue units were exercised, both of which would result in the issuance of additional units that would then share in our net income.

(3) Represents the amount of cash distributions declared with respect to that year.

(4) For the purpose of computing the ratio of earnings to fixed charges, earnings are defined as income from continuing operations before income taxes and cumulative effect of a change in accounting principle, and before minority interest in consolidated subsidiaries, equity earnings (including amortization of excess cost of equity investments) and unamortized capitalized interest, plus fixed charges and distributed income of equity investees. Fixed charges are defined as the sum of interest on all indebtedness (excluding capitalized interest), amortization of debt issuance costs and that portion of rental expense which we believe to be representative of an interest factor.

(5) Excludes value of interest rate swaps. Increases to long-term debt for value of interest rate swaps totaled $152.2 million as of December 31, 2007, $42.6 million as of December 31, 2006, $98.5 million as of December 31, 2005, $130.2 million as of December 31, 2004, and $121.5 million as of December 31, 2003.

(6) Includes results of operations for an approximate 50.2% interest in the Cochin pipeline system, the Vancouver Wharves marine terminal, and terminal assets acquired from Marine Terminals, Inc. since effective dates of acquisition. We acquired the remaining 50.2% interest in Cochin that we did not already own from affiliates of BP effective January 1, 2007. We acquired the Vancouver Wharves bulk marine terminal operations from British Columbia Railway Company effective May 30, 2007, and we acquired certain bulk terminal assets from Marine Terminals, Inc. effective September 1, 2007. Also includes Trans Mountain since January 1, 2007 as discussed below.

(7) Includes results of operations for the net assets of Trans Mountain acquired on April 30, 2007 from Knight Inc. (formerly Kinder Morgan, Inc.) since January 1, 2006. Also includes results of operations for the oil and gas properties acquired from Journey Acquisition-I, L.P. and Journey 2000, L.P., the terminal assets and operations acquired from A&L Trucking, L.P. and U.S. Development Group, Transload Services, LLC, and Devco USA L.L.C. since effective dates of acquisition. The April 5, 2006 acquisition of the Journey oil and gas properties were made effective March 1, 2006. The assets and operations acquired from A&L Trucking and U.S. Development Group were acquired in three separate transactions in April 2006. We acquired all of the membership interests in Transload Services, LLC effective November 20, 2006, and we acquired all of the membership interests in Devco USA L.L.C. effective December 1, 2006. We also acquired a 66 2/3% ownership interest in Entrega Pipeline LLC effective February 23, 2006, however, our earnings were not materially impacted during 2006 due to the fact that regulatory accounting provisions required capitalization of revenues and expenses until the second segment of the Entrega Pipeline was complete and in-service.

(8) Includes results of operations for the 64.5% interest in the Claytonville unit, the seven bulk terminal operations acquired from Trans-Global Solutions, Inc., the Kinder Morgan Staten Island terminal, the terminal facilities located in Hawesville, Kentucky and Blytheville, Arkansas, General Stevedores, L.P., the North Dayton natural gas storage facility, the Kinder Morgan Blackhawk terminal, the terminal repair shop acquired from Trans-Global Solutions, Inc., and the terminal assets acquired from Allied Terminals, Inc. since effective dates of acquisition. We acquired the 64.5% interest in the Claytonville unit effective January 31, 2005. We acquired the seven bulk terminal operations from Trans-Global Solutions, Inc. effective April 29, 2005. The Kinder Morgan Staten Island terminal, the Hawesville, Kentucky terminal and the Blytheville, Arkansas terminal were each acquired separately in July 2005. We acquired all of the partnership interests in General Stevedores, L.P. effective July 31, 2005. We acquired the North Dayton natural gas storage facility effective August 1, 2005. We acquired the Kinder Morgan Blackhawk terminal in August 2005 and the terminal repair shop in September 2005. We acquired the terminal assets from Allied Terminals, Inc. effective November 4, 2005.

(9) Includes results of operations for the seven refined petroleum products terminals acquired from ExxonMobil, Kinder Morgan Wink Pipeline, L.P., an additional 5% interest in the Cochin Pipeline System, Kinder Morgan River Terminals LLC and its consolidated subsidiaries, TransColorado Gas Transmission Company LLC, interests in nine refined petroleum products terminals acquired from Charter Terminal Company and Charter-Triad Terminals, LLC, and the Kinder Morgan

Fairless Hills terminal since effective dates of acquisition. We acquired the seven refined petroleum products terminals from ExxonMobil effective March 9, 2004. We acquired Kinder Morgan Wink Pipeline, L.P. effective August 31, 2004. The additional interest in Cochin was acquired effective October 1, 2004. We acquired Kinder Morgan River Terminals LLC and its consolidated subsidiaries effective October 6, 2004. We acquired TransColorado effective November 1, 2004, the interests in the nine Charter Terminal Company and Charter-Triad Terminals, LLC refined petroleum products terminals effective November 5, 2004, and the Kinder Morgan Fairless Hills terminal effective December 1, 2004.

(10) Includes results of operations for the bulk terminal operations acquired from M.J. Rudolph Corporation, the additional 12.75% interest in the SACROC unit, the five refined petroleum products terminals acquired from Shell, the additional 42.5% interest in the Yates field unit, the crude oil gathering operations surrounding the Yates field unit, an additional 65% interest in the Pecos Carbon Dioxide Company, the remaining approximate 32% interest in MidTex Gas Storage Company, LLP, the seven refined petroleum products terminals acquired from ConocoPhillips and two bulk terminal facilities located in Tampa, Florida since dates of acquisition. We acquired certain bulk terminal operations from M.J. Rudolph effective January 1, 2003. The additional 12.75% interest in SACROC was acquired effective June 1, 2003. The five refined petroleum products terminals were acquired effective October 1, 2003. The additional 42.5% interest in the Yates field unit, the Yates gathering system and the additional 65% interest in Pecos Carbon Dioxide Company were acquired effective November 1, 2003. The additional 32% ownership interest in MidTex was acquired November 1, 2003. The seven refined petroleum products terminals were acquired December 11, 2003, and the two bulk terminal facilities located in Tampa, Florida were acquired effective December 10 and 23, 2003.

Item 7. ***Management’s Discussion and Analysis of Financial Condition and Results of Operations.***

The following discussion and analysis of our financial condition and results of operations provides a narrative of our financial results. It contains a discussion and analysis of the results of operations for each segment of our business, followed by a discussion and analysis of our financial condition. The following discussion and analysis is based on our consolidated financial statements, which are included elsewhere in this report and were prepared in accordance with accounting principles generally accepted in the United States of America.

The following discussion and analysis should be read in conjunction with our consolidated financial statements included elsewhere in this report. Additional sections in this report which should be helpful to the reading of our discussion and analysis include the following: (i) a description of our business strategy found in Items 1 and 2 "Business and Properties—(c) Narrative Description of Business—Business Strategy;" (ii) a description of developments during 2007, found in Items 1 and 2 "Business and Properties—(a) General Development of Business—Recent Developments;" and (iii) a description of risk factors affecting us and our business, found in Item 1A "Risk Factors."

In addition, as discussed in Note 3 of the accompanying notes to our consolidated financial statements, our financial statements reflect:

- the April 30, 2007 transfer of Trans Mountain as if such transfer had taken place on January 1, 2006, the effective date of common control pursuant to generally accepted accounting principles. The financial information contained in this Management’s Discussion and Analysis of Financial Condition and Results of Operations includes the financial results of Trans Mountain for all periods subsequent to January 1, 2006; and
- the reclassifications necessary to reflect the results of our North System as discontinued operations. However, due to the fact that the sale of our North System does not change the structure of our internal organization in a manner that causes a change to our reportable business segments pursuant to the provisions of SFAS No. 131, "Disclosures about Segments of an Enterprise and Related Information," we have included the North System’s financial results within our Products Pipelines business segment disclosures for all periods presented in this report.

We begin with a discussion of our Critical Accounting Polices and Estimates, those areas that are both very important to the portrayal of our financial condition and results and which require our management’s most difficult, subjective or complex judgments, often as a result of the need to make estimates about the effect of matters that are inherently uncertain.

Critical Accounting Policies and Estimates

Accounting standards require information in financial statements about the risks and uncertainties inherent in significant estimates, and the application of generally accepted accounting principles involves the exercise of varying degrees of judgment. Certain amounts included in or affecting our consolidated financial statements and related disclosures must be estimated, requiring us to make certain assumptions with respect to values or conditions that cannot be known with certainty at the time the financial statements are prepared. These estimates and assumptions affect the amounts we report for our assets and liabilities, our revenues and expenses during the reporting period, and our disclosure of contingent assets and liabilities at the date of our financial statements.

We routinely evaluate these estimates, utilizing historical experience, consultation with experts and other methods we consider reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from our estimates. Any effects on our business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known.

In preparing our consolidated financial statements and related disclosures, examples of certain areas that require more judgment relative to others include our use of estimates in determining:

- the economic useful lives of our assets;
- the fair values used to allocate purchase price and to determine possible asset impairment charges;
- reserves for environmental claims, legal fees, transportation rate cases and other litigation liabilities;
- provisions for uncollectible accounts receivables;
- exposures under contractual indemnifications; and
- unbilled revenues.

For a summary of our significant accounting policies, see Note 2 to our consolidated financial statements included elsewhere in this report. We believe that certain accounting policies are of more significance in our consolidated financial statement preparation process than others, which policies are discussed as follows.

Environmental Matters

With respect to our environmental exposure, we utilize both internal staff and external experts to assist us in identifying environmental issues and in estimating the costs and timing of remediation efforts. We expense or capitalize, as appropriate, environmental expenditures that relate to current operations, and we record environmental liabilities when environmental assessments and/or remedial efforts are probable and we can reasonably estimate the costs. We do not discount environmental liabilities to a net present value, and we recognize receivables for anticipated associated insurance recoveries when such recoveries are deemed to be probable.

Our recording of our environmental accruals often coincides with our completion of a feasibility study or our commitment to a formal plan of action, but generally, we recognize and/or adjust our environmental liabilities following routine reviews of potential environmental issues and claims that could impact our assets or operations. These adjustments may result in increases in environmental expenses and are primarily related to quarterly reviews of potential environmental issues and resulting environmental liability estimates.

These environmental liability adjustments are recorded pursuant to our management's requirement to recognize contingent environmental liabilities whenever the associated environmental issue is likely to occur and the amount of our liability can be reasonably estimated. In making these liability estimations, we consider the effect of environmental compliance, pending legal actions against us, and potential third-party liability claims. For more information on our environmental disclosures, see Note 16 to our consolidated financial statements included elsewhere in this report.

Legal Matters

We are subject to litigation and regulatory proceedings as a result of our business operations and transactions. We utilize both internal and external counsel in evaluating our potential exposure to adverse outcomes from orders, judgments or settlements. To the extent that actual outcomes differ from our estimates, or additional facts and circumstances cause us to revise our estimates, our earnings will be affected. In general, we expense legal costs as incurred. When we identify specific litigation that is expected to continue for a significant period of time and require substantial expenditures, we identify a range of possible costs expected to be required to litigate the matter to a conclusion or reach an acceptable settlement. If no amount within this range is a better estimate than any other amount, we record a liability equal to the low end of the range. Any such liability recorded is revised as better information becomes available.

As of December 31, 2007, our most significant ongoing litigation proceedings involve our SFPP, L.P, subsidiary, which is the limited partnership that owns our Pacific operations' pipelines, excluding CALNEV Pipe Line LLC. Tariffs charged by our Pacific operations' pipeline systems are subject to certain proceedings at the FERC involving shippers' complaints regarding the interstate rates, as well as practices and the jurisdictional nature of certain facilities and services. Generally, the interstate rates on our Pacific operations' pipeline systems are "grandfathered" under the Energy Policy Act of 1992 unless "substantially changed circumstances" are found to exist. To the extent "substantially changed circumstances" are found to exist, our Pacific operations may be subject to substantial exposure under these FERC complaints and could, therefore, owe reparations and/or refunds to complainants as mandated by the FERC or the United States' judicial system. For more information on our Pacific operations' regulatory proceedings, see Note 16 to our consolidated financial statements included elsewhere in this report.

Intangible Assets

Intangible assets are those assets which provide future economic benefit but have no physical substance. We account for our intangible assets according to the provisions of Statement of Financial Accounting Standards No. 141, "Business Combinations" and Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets." These accounting pronouncements introduced the concept of indefinite life intangible assets and provided that all identifiable intangible assets having indefinite useful economic lives, including goodwill, will not be subject to regular periodic amortization. Such assets are not to be amortized until their lives are determined to be finite. Instead, the carrying amount of a recognized intangible asset with an indefinite useful life must be tested for impairment annually or on an interim basis if events or circumstances indicate that the fair value of the asset has decreased below its carrying value. We have selected an impairment measurement test date of January 1 of each year, and we have determined that our goodwill was not impaired as of January 1, 2008.

As of December 31, 2007, our goodwill was $1,077.8 million. Included in this goodwill balance is $251.0 million related to our Trans Mountain business segment, which we acquired from Knight on April 30, 2007. Following the provisions of generally accepted accounting principles, this transaction caused Knight to consider the fair value of the Trans Mountain pipeline system, and to determine whether goodwill related to these assets was impaired. Knight recorded a goodwill impairment charge of $377.1 million in the first quarter of 2007. This impairment is also reflected on our books due to the accounting principles for transfers of assets between entities under common control, which require us to account for Trans Mountain as if the transfer had taken place on January 1, 2006.

Our remaining intangible assets, excluding goodwill, include customer relationships, contracts and agreements, technology-based assets and lease value. These intangible assets have definite lives, are being amortized on a straight-line basis over their estimated useful lives, and are reported separately as "Other intangibles, net" in our accompanying consolidated balance sheets. As of December 31, 2007 and 2006, these intangibles totaled $238.6 million and $213.2 million, respectively.

Estimated Net Recoverable Quantities of Oil and Gas

We use the successful efforts method of accounting for our oil and gas producing activities. The successful efforts method inherently relies on the estimation of proved reserves, both developed and undeveloped. The existence and the estimated amount of proved reserves affect, among other things, whether certain costs are capitalized or expensed, the amount and timing of costs depleted or amortized into income and the presentation of supplemental information on oil and gas producing activities. The expected future cash flows to be generated by oil and gas producing properties used in testing for impairment of such properties also rely in part on estimates of net recoverable quantities of oil and gas.

Proved reserves are the estimated quantities of oil and gas that geologic and engineering data demonstrates with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Estimates of proved reserves may change, either positively or negatively, as additional information becomes available and as contractual, economic and political conditions change.

Hedging Activities

We engage in a hedging program that utilizes derivative contracts to mitigate (offset) our exposure to fluctuations in energy commodity prices and to balance our exposure to fixed and floating interest rates, and we believe that these hedges are generally effective in realizing these objectives. However, the accounting standards regarding hedge accounting are complex, and even when we engage in hedging transactions that are effective economically, these transactions may not be considered effective for accounting purposes.

According to the provisions of current accounting standards, to be considered effective, changes in the value of a derivative contract or its resulting cash flows must substantially offset changes in the value or cash flows of the item being hedged. A perfectly effective hedge is one in which changes in the value of the derivative contract exactly offset changes in the value of the hedged item or expected cash flow of the future transactions in reporting periods covered by the derivative contract. The ineffective portion of the gain or loss and any component excluded from the computation of the effectiveness of the derivative contract must be reported in earnings immediately; accordingly, our financial statements may reflect some volatility due to these hedges.

In addition, it is not always possible for us to engage in a hedging transaction that completely mitigates our exposure to unfavorable changes in commodity prices. For example, when we purchase a commodity at one location and sell it at another, we may be unable to hedge completely our exposure to a differential in the price of the product between these two locations. Even when we cannot enter into a completely effective hedge, we often enter into hedges that are not completely effective in those instances where we believe to do so would be better than not hedging at all, but due to the fact that the part of the hedging transaction that is not effective in offsetting undesired changes in commodity prices (the ineffective portion) is required to be recognized currently in earnings, our financial statements may reflect a gain or loss arising from an exposure to commodity prices for which we are unable to enter into a completely effective hedge.

Results of Operations

Our business model is built to support two principal components:

- helping customers by providing energy, bulk commodity and liquids products transportation, storage and distribution; and
- creating long-term value for our unitholders.

To achieve these objectives, we focus on providing fee-based services to customers from a business portfolio consisting of energy-related pipelines, bulk and liquids terminal facilities, and carbon dioxide and petroleum reserves. Our reportable business segments are based on the way our management organizes our enterprise, and each of our five segments represents a component of our enterprise that engages in a separate business activity and for which discrete financial information is available.

Consolidated

	Year Ended December 31,		
	2007	2006	2005
		(In millions)	
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments(a)			
Products Pipelines(b)	$ 569.6	$ 491.2	$ 370.1
Natural Gas Pipelines(c)	600.2	574.8	500.3
CO_2 (d)	537.0	488.2	470.9
Terminals(e)	416.0	408.1	314.6
Trans Mountain(f)	(293.6)	76.5	—
Segment earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	1,829.2	2,038.8	1,655.9
Depreciation, depletion and amortization expense(g)	(547.0)	(432.8)	(349.8)
Amortization of excess cost of equity investments	(5.8)	(5.7)	(5.6)
Interest and corporate administrative expenses(h)	(686.1)	(596.2)	(488.3)
Net income	$ 590.3	$ 1,004.1	$ 812.2

(a) Includes revenues, earnings from equity investments, allocable interest income and other, net, less operating expenses, allocable income taxes, and other expense (income). Operating expenses include natural gas purchases and other costs of sales, operations and maintenance expenses, fuel and power expenses, and taxes, other than income taxes.

(b) 2007 amount includes (i) a $152.8 million gain from the sale of our North System; (ii) a $136.8 million increase in expense associated with rate case and other legal liability adjustments; (iii) a $15.9 million increase in expense associated with environmental liability adjustments; (iv) a $15.0 million expense for a litigation settlement reached with Contra Costa County, California; (v) a $3.2 million increase in expense from the settlement of certain litigation matters related to our West Coast refined products terminal operations; and (vi) a $1.8 million increase in income resulting from unrealized foreign currency gains on long-term debt transactions. 2006 amount includes a $16.5 million increase in expense associated with environmental liability adjustments, and a $5.7 million increase in income resulting from certain transmix contract settlements. 2005 amount includes a $105.0 million increase in expense resulting from a rate case liability adjustment, a $13.7 million increase in expense resulting from a North System liquids inventory reconciliation adjustment, and a $19.6 million increase in expense associated with environmental liability adjustments.

(c) 2007 amount includes an expense of $1.0 million, reflecting our portion of a loss from the early extinguishment of debt by Red Cedar Gathering Company, and a $0.4 million decrease in expense associated with environmental liability adjustments. 2006 amount includes a $1.5 million increase in expense associated with environmental liability adjustments, a $15.1 million gain from the combined sale of our Douglas natural gas gathering system and Painter Unit fractionation facility, and a $6.3 million reduction in expense due to the release of a reserve related to a natural gas purchase/sales contract. 2005 amount includes a $0.1 million reduction in expense associated with environmental liability adjustments.

(d) 2007 amount includes a $0.2 million increase in expense associated with environmental liability adjustments. 2006 amount includes a $1.8 million loss on derivative contracts used to hedge forecasted crude oil sales. 2005 amount includes a $0.3 million increase in expense associated with environmental liability adjustments.

(e) 2007 amount includes (i) a $25.0 million increase in expense from the settlement of certain litigation matters related to our Cora coal terminal; (ii) a $2.0 million increase in expense associated with environmental liability adjustments; (iii) an increase in income of $1.8 million from property casualty gains associated with the 2005 hurricane season; and (iv) a $1.2 million increase in expense associated with legal liability adjustments. 2006 amount includes an $11.3 million net increase in income from the net effect of a property casualty insurance gain and incremental repair and clean-up expenses (both associated with the 2005 hurricane season). 2005 amount includes a $3.5 million increase in expense associated with environmental liability adjustments.

(f) As discussed in Note 3 to our consolidated financial statements included elsewhere in this report, our consolidated financial statements, and all other financial information included in this report, are presented as though the April 30, 2007 transfer of Trans Mountain net assets had occurred on the date when both Trans Mountain and we met the accounting requirements for entities under common control (January 1, 2006). 2007 amount includes losses of $349.2 million for periods prior to our acquisition date of April 30, 2007 (including a goodwill impairment expense of $377.1 million), and a $1.3 million decrease in income from an oil loss allowance. 2006 amount represents earnings for a period prior to our acquisition date of April 30, 2007.

(g) 2007 and 2006 amounts include Trans Mountain expenses of $6.3 million and $19.0 million, respectively, for periods prior to our acquisition date of April 30, 2007.

(h) Includes unallocated interest income and income tax expense, interest and debt expense, general and administrative expenses (including unallocated litigation and environmental expenses), and minority interest expense. 2007 amount includes the following: (i) a $26.2 million increase in expense, allocated to us from Knight, associated with closing the going-private transaction. Knight Inc. was responsible for the payment of the costs resulting from this transaction; (ii) a combined $6.7 million increase in expense, related to Trans Mountain interest and general and administrative expenses for periods prior to our acquisition date of April 30, 2007; (iii) a $2.4 million increase in interest expense related to our Cochin Pipeline acquisition; (iv) a $2.1 million expense due to the adjustment of certain insurance related liabilities; (v) a $1.7 million increase in expense associated with the 2005 hurricane season; (vi) a $1.5 million expense for certain Trans Mountain acquisition costs; (vii) a $0.8 million expense related to the cancellation of certain commercial insurance policies; and (viii) a total $3.9 million decrease in minority interest expense, related to the minority interest effect from all of the previously listed items. 2006 amount includes a combined $25.1 million expense related to Trans Mountain interest and general and administrative expenses, a $2.0 million increase in expense, primarily related to the cancellation of certain commercial insurance policies and a $3.5 million increase in minority interest expense, primarily related to the minority interest effect from the property casualty insurance gain described in footnote (e). 2005 amount includes a $25.0 million expense for a litigation settlement reached between us and a former joint venture partner on our Kinder Morgan Tejas natural gas pipeline system, a cumulative $8.4 million expense related to settlements of environmental matters at certain of our operating sites located in the state of California, and a $3.0 million decrease in expense related to proceeds received in connection with the settlement of claims in the Enron Corp. bankruptcy proceeding.

For the year 2007, our net income was $590.3 million on revenues of $9,217.7 million. This compares with net income of $1,004.1 million on revenues of $9,048.7 million in 2006, and net income of $812.2 million on revenues of $9,745.9 million in 2005. The certain items described in the footnotes to the table above account for $483.3 million of the year-to-year decrease of $413.8 million. The remaining increase in net income is associated with better performance from our operating segments.

The primary reason for the decrease in our 2007 net income, when compared to last year, was related to an impairment expense of $377.1 million associated with a non-cash reduction in the carrying value of Trans Mountain's goodwill. Included within the certain items footnoted in the table above, and discussed above in " — Intangibles," the goodwill impairment charge was recognized by Knight in March 2007. Following our purchase of Trans Mountain from Knight on April 30, 2007, the financial results of Trans Mountain since January 1, 2006, including the impact of the goodwill impairment, are reflected in our results. Also, our overall carrying value for the net assets of Trans Mountain reflects Knight's carrying value, which is considerably higher than the cash price we paid. For more information on this acquisition and the goodwill impairment, see Notes 3 and 8 to our consolidated financial statements included elsewhere in this report.

Segment earnings before depreciation, depletion and amortization expenses

Because our partnership agreement requires us to distribute 100% of our available cash to our partners on a quarterly basis (available cash consists primarily of all our cash receipts, less cash disbursements and changes in reserves), we consider each period's earnings before all non-cash depreciation, depletion and amortization expenses, including amortization of excess cost of equity investments, to be an important measure of our success in maximizing returns to our partners. We also use segment earnings before depreciation, depletion and amortization expenses (defined in the table above and sometimes referred to in this report as EBDA) internally as a measure of profit and loss used for evaluating segment performance and for deciding how to allocate resources to our five reportable business segments.

Combined, the certain items described in the footnotes to the table above decreased total segment earnings before depreciation, depletion and amortization by $489.1 million in 2007, relative to 2006 (combining to decrease total segment EBDA by $394.0 million in 2007 and to increase segment EBDA by $95.1 million in 2006). The remaining $279.5 million (14%) increase in segment earnings before depreciation, depletion and amortization in 2007 versus 2006 was driven by strong financial results from increased margins on natural gas transport, storage and processing activities, incremental earnings from dry-bulk product and petroleum liquids terminal operations, higher crude oil and natural gas liquids revenues, incremental earnings from completed expansion projects, and our acquisition of the Trans Mountain pipeline system and the remaining interest in the Cochin pipeline system that we did not already own.

In 2006, the certain items described above combined to increase total segment earnings before depreciation, depletion and amortization by$237.1 million, compared to the previous year (combining to increase total segment EBDA by $95.1 million in 2006 and to decrease segment EBDA by $142.0 million in 2005). The remaining $145.8 million (8%) increase in segment earnings before depreciation, depletion and amortization in 2006 versus 2005 was primarily attributable to internal growth and expansion across our business portfolio and to incremental contributions from assets and operations acquired since the end of 2005.

Products Pipelines

	Year Ended December 31,		
	2007	**2006**	**2005**
	(In millions, except operating statistics)		
Revenues	$ 844.4	$ 776.3	$ 711.8
Operating expenses(a)	(451.8)	(308.3)	(366.0)
Other income(b)	154.8	—	—
Earnings from equity investments(c)	32.5	16.3	28.5
Interest income and Other, net-income (expense)(d)	9.4	12.1	6.1
Income tax benefit (expense)(e)	(19.7)	(5.2)	(10.3)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	$ 569.6	$ 491.2	$ 370.1
Gasoline (MMBbl)	435.5	449.8	452.1
Diesel fuel (MMBbl)	164.1	158.2	163.1
Jet fuel (MMBbl)	125.1	119.5	118.1
Total refined product volumes (MMBbl)	724.7	727.5	733.3
Natural gas liquids (MMBbl)	30.4	34.0	33.5
Total delivery volumes (MMBbl)(f)	755.1	761.5	766.8

(a) 2007, 2006 and 2005 amounts include increases in expense of $15.9 million, $13.5 million and $19.6 million, respectively, associated with environmental liability adjustments. 2007 amount also includes a $136.7 million increase in expense associated with rate case and other legal liability adjustments, a $15.0 million expense for a litigation settlement reached with Contra Costa County, California, and a $3.2 million increase in expense from the settlement of certain litigation matters related to our West Coast refined products terminal operations. 2005 amount also includes a $105.0 million increase in expense associated with a rate case liability adjustment, and a $13.7 million increase in expense associated with a North System liquids inventory reconciliation adjustment.

(b) 2007 amount includes a $152.8 million gain from the sale of our North System.

(c) 2007 amount includes a $0.1 million increase in expense associated with our proportional share of legal liability adjustments on Plantation Pipe Line Company. 2006 amount includes a $4.9 million increase in expense associated with our proportional share of environmental liability adjustments on Plantation Pipe Line Company.

(d) 2007 amount includes a $1.8 million increase in income resulting from unrealized foreign currency gains on long-term debt transactions. 2006 amount includes a $5.7 million increase in income resulting from transmix contract settlements.

(e) 2006 amount includes a $1.9 million decrease in expense associated with our proportional share of the tax effect on our share of environmental expenses incurred by Plantation Pipe Line Company and described in footnote (c).

(f) Includes Pacific, Plantation, CALNEV, Central Florida, Cochin, and Cypress pipeline volumes.

Our Products Pipelines segment’s primary businesses include transporting refined petroleum products and natural gas liquids through pipelines and operating liquid petroleum products terminals and petroleum pipeline transmix processing facilities. Combined, the certain items described in the footnotes to the table above decreased earnings before depreciation, depletion and amortization by $5.5 million in 2007 compared to 2006, and increased earnings before depreciation, depletion and amortization by $127.5 million in 2006 compared to 2005.

Following is information related to the remaining increases and decreases in the segment’s (i) earnings before depreciation, depletion and amortization expenses (EBDA); and (ii) operating revenues in both 2007 and 2006, when compared to the respective prior year:

Year Ended December 31, 2007 versus Year Ended December 31, 2006

	EBDA increase/(decrease)		Revenues Increase/(decrease)	
	(In millions, except percentages)			
Cochin Pipeline System	$ 30.0	212%	$ 39.2	110%
West Coast Terminals	12.3	34%	7.5	12%
Plantation Pipeline	8.6	27%	1.0	2%
Transmix operations	8.0	36%	10.6	32%
Pacific operations	5.8	2%	18.4	5%
CALNEV Pipeline	5.1	11%	3.4	5%
Southeast Terminals	5.0	13%	(12.9)	(16)%
North System	4.9	21%	(2.6)	(6)%
All other (including eliminations)	4.2	11%	3.5	7%
Total Products Pipelines	$ 83.9	17%	$ 68.1	9%

Year Ended December 31, 2006 versus Year Ended December 31, 2005

	EBDA Increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Cochin Pipeline System	$ (5.2)	(27)%	$ (0.5)	(1)%
Southeast Terminals	4.9	15%	24.5	43%
Plantation Pipeline	(4.2)	(12)%	1.5	4%
Pacific operations	(5.4)	(2)%	16.2	5%
West Coast Terminals	(2.6)	(7)%	6.5	11%
Transmix operations	2.6	13%	3.9	13%
All other (including eliminations)	3.5	3%	12.4	8%
Total Products Pipelines	$ (6.4)	(1)%	$ 64.5	9%

All of the assets in our Products Pipelines business segment produced higher earnings before depreciation, depletion and amortization expenses in 2007 than in the previous year. The overall increase in segment earnings before depreciation, depletion and amortization in 2007 compared to 2006 was driven largely by incremental earnings from our Cochin pipeline system. The higher earnings and revenues from Cochin were largely attributable to our January 1, 2007 acquisition of the remaining approximate 50.2% ownership interest that we did not already own. Upon closing of the transaction, we became the operator of the pipeline. For more information on this acquisition, see Note 3 to our consolidated financial statements included elsewhere in this report.

The year-to-year earnings increase from our West Coast terminal operations in 2007 was due to higher operating revenues, lower operating expenses and incremental gains from asset sales. The increases in terminal revenues were driven by higher throughput volumes from our combined Carson/Los Angeles Harbor terminal system, partly due to completed storage expansion projects since the end of 2006, and from our Linnton and Willbridge terminals located in Portland, Oregon. The decrease in operating expenses in 2007 versus 2006 was largely related to higher environmental expenses recognized in 2006, due to adjustments to accrued environmental liabilities (these incremental environmental expenses were not associated with the expenses described in footnote (a) to the table above).

The increase in earnings in 2007 from our approximate 51% equity investment in Plantation Pipe Line Company was due to higher overall net income earned by Plantation, largely resulting from both higher pipeline revenues and lower period-to-period operating expenses. The increase in revenues was largely due to a higher oil loss allowance percentage in 2007, relative to last year, and the drop in operating expenses—including fuel, power and pipeline maintenance expenses, was due to decreases in both refined products delivery volumes and pipeline integrity expenses in 2007 versus 2006 (pipeline integrity expenses are discussed more fully below).

The year-to-year increase in earnings before depreciation, depletion and amortization from our petroleum pipeline transmix operations was directly related to higher revenues, reflecting incremental revenues from our Greensboro, North Carolina facility and higher processing revenues from our Colton, California facility. In May 2006, we completed construction and placed into service the Greensboro facility, and during 2007, the plant

processed greater volumes than in 2006. In 2007, our Greensboro facility contributed incremental earnings before depreciation, depletion and amortization of $4.5 million and incremental revenues of $5.4 million in 2007 compared to 2006. The increases in earnings and revenues from our Colton facility, which processes transmix generated from volumes transported to the Southern California and Arizona markets by our Pacific operations' pipelines, were primarily due to year-to-year increases in average processing contract rates.

We also benefited from higher earnings before depreciation, depletion and amortization from our Pacific operations, our CALNEV Pipeline and our North System in 2007, when compared to last year. The increase in our Pacific operations' earnings was largely revenue related, attributable to increases in both transportation volumes and average tariff rates. Combined mainline delivery and terminal revenues increased 5% in 2007, compared to 2006, due largely to higher delivery volumes to Arizona, the completed expansion of our East Line pipeline during the summer of 2006, and higher deliveries to various West Coast military bases. The increase from CALNEV was also driven by higher year-over-year revenues, due to increased military and commercial tariff rates in 2007, and higher terminal revenues associated with ethanol blending at our Las Vegas terminal that more than offset a 2% drop in refined products delivery volumes. The increase from our North System was mainly due to lower combined operating expense, due to its sale in the fourth quarter of 2007 (the decline in expense was greater than the associated decline in revenue).

Effective October 5, 2007, we sold our North System common carrier natural gas liquids pipeline and our 50% ownership interest in the Heartland Pipeline Company to ONEOK Partners, L.P. for approximately $298.6 million, and we used the proceeds we received to pay down short-term debt borrowings. We accounted for our North System business as a discontinued operation pursuant to generally accepted accounting principles which require that the income statement be formatted to separate the divested business from our continuing operations; however, consistent with the management approach of identifying and reporting financial information on operating segments, we have included the North System's financial results within our Products Pipelines business segment disclosures for all periods presented in this discussion and analysis. This decision was based on the way our management organizes segments internally to make operating decisions and assess performance. We do not expect the impact of the discontinued operations to materially affect our overall business, financial position, results of operations or cash flows. For information on our reconciliation of segment information with our consolidated general-purpose financial statements, see Note 15 to our consolidated financial statements included elsewhere in this report.

Combining all of the segment's operations, while revenues from refined petroleum products deliveries increased 6.2% in 2007, compared to last year, total refined products delivery volumes decreased 0.4%. Compared to last year, gasoline delivery volumes decreased 3.2% (primarily due to Plantation), while diesel and jet fuel volumes were up 3.7% and 4.7%, respectively. Excluding Plantation, which continued to be impacted by a competing pipeline that began service in mid-2006, total refined products delivery volumes increased by 0.8% in 2007, when compared to 2006. Volumes on our Pacific operations and our Central Florida pipelines were up 1% and 2%, respectively, in 2007, and while natural gas liquids delivery volumes were down in 2007 versus 2006, revenues were up substantially due to our increased ownership in the Cochin pipeline system.

The $6.4 million (1%) decrease in earnings before depreciation, depletion and amortization expenses in 2006, when compared to 2005, was largely due to a combined decrease in earnings of $24.2 million in 2006—due to incremental pipeline maintenance expenses recognized in the last half of the year. Beginning in the third quarter of 2006, the refined petroleum products pipelines and associated terminal operations included within our Products Pipelines segment (including Plantation Pipe Line Company, our 51%-owned equity investee) began recognizing certain costs incurred as part of their pipeline integrity management program as maintenance expense in the period incurred, and in addition, recorded an expense for costs previously capitalized during the first six months of 2006. Combined, this change reduced the segment's earnings before depreciation, depletion and amortization expenses by $24.2 million in 2006—increasing maintenance expenses by $20.1 million, decreasing earnings from equity investments by $6.6 million, and decreasing income tax expenses by $2.5 million.

Pipeline integrity costs encompass those costs incurred as part of an overall pipeline integrity management program, which is a process for assessing and mitigating pipeline risks in order to reduce both the likelihood and consequences of incidents. Our pipeline integrity program is designed to provide our management the information needed to effectively allocate resources for appropriate prevention, detection and mitigation activities.

The remaining $17.8 million (4%) increase in earnings before depreciation, depletion and amortization expenses in 2006 compared with 2005, primarily consisted of the following items:

- a $4.9 million (15%) increase from our Southeast refined products terminal operations, driven by higher liquids throughput volumes at higher rates, relative to 2005, and higher margins from ethanol blending and sales activities;
- a $4.1 million (1%) increase from our combined Pacific and CALNEV Pipeline operations, primarily due to a $22.6 million (6%) increase in operating revenues, which more than offset an $18.3 million (18%) increase in combined operating expenses. The increase in operating revenues consisted of a $14.7 million (5%) increase from refined products deliveries and a $7.9 million (8%) increase from terminal and other fee revenue. The increase in operating expenses was primarily due to higher fuel and power expenses; and
- a $3.7 million (12%) increase from our Central Florida Pipeline, mainly due to higher product delivery revenues in 2006 driven by higher average tariff and terminal rates.

Combining all of the segment's operations, while total delivery volumes of refined petroleum products decreased 0.8% in 2006 compared to 2005, total delivery volumes from our Pacific operations were up 1.7% compared to 2005, due in part to the East Line expansion which was in service for the last seven months of 2006. The expansion project substantially increased pipeline capacity from El Paso, Texas to Tucson and Phoenix, Arizona. In addition, our CALNEV Pipeline delivery volumes were up 4.2% in 2006 versus 2005, due primarily to strong demand from the Southern California and Las Vegas, Nevada markets. The overall decrease in year-to-year segment deliveries of refined petroleum products was largely related to a 6.8% drop in volumes from the Plantation Pipeline in 2006, as described above.

Natural Gas Pipelines

	Year Ended December 31,		
	2007	**2006**	**2005**
	(In millions, except operating statistics)		
Revenues	$ 6,466.5	$ 6,577.7	$ 7,718.4
Operating expenses(a)	(5,882.9)	(6,057.8)	(7,255.0)
Other income(b)	3.2	15.1	—
Earnings from equity investments(c)	19.2	40.5	36.8
Interest income and Other, net-income (expense)	0.2	0.7	2.7
Income tax benefit (expense)	(6.0)	(1.4)	(2.6)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	$ 600.2	$ 574.8	$ 500.3
Natural gas transport volumes (Trillion Btus)(d)	1,577.3	1,440.9	1,317.9
Natural gas sales volumes (Trillion Btus)(e)	865.5	909.3	924.6

(a) 2007, 2006 and 2005 amounts include a $0.4 million decrease in expense, a $1.5 million increase in expense and a $0.1 million decrease in expense, respectively, associated with environmental liability adjustments. 2006 amount also includes a $6.3 million reduction in expense due to the release of a reserve related to a natural gas purchase/sales contract.

(b) 2006 amount represents a $15.1 million gain from the combined sale of our Douglas natural gas gathering system and Painter Unit fractionation facility.

(c) 2007 amount includes an expense of $1.0 million reflecting our portion of a loss from the early extinguishment of debt by Red Cedar Gathering Company.

(d) Includes Rocky Mountain pipeline group and Texas intrastate natural gas pipeline group pipeline volumes.

(e) Represents Texas intrastate natural gas pipeline group.

Our Natural Gas Pipelines segment's primary businesses involve marketing, transporting, storing, gathering, treating and processing natural gas through both intrastate and interstate pipeline systems and related facilities. Combined, the certain items described in the footnotes to the table above decreased earnings before depreciation, depletion and amortization by $20.5 million in 2007, relative to 2006, and increased earnings before depreciation, depletion and amortization by $19.8 million in 2006, relative to 2005.

Following is information related to the remaining increases and decreases in the segment's (i) earnings before depreciation, depletion and amortization expenses (EBDA); and (ii) operating revenues in both 2007 and 2006, when compared to the respective prior year:

Year Ended December 31, 2007 versus Year Ended December 31, 2006

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Texas Intrastate Natural Gas Pipeline Group	$ 57.0	19%	$ (142.2)	(2)%
Casper and Douglas gas processing	8.6	67%	5.6	6%
Rocky Mountain Pipeline Group	(11.6)	(6)%	29.0	10%
Red Cedar Gathering Company	(7.4)	(20)%	—	—
All others	(0.7)	(15)%	(3.8)	(94)%
Intrasegment Eliminations	—	—	0.2	11%
Total Natural Gas Pipelines	$ 45.9	8%	$ (111.2)	(2)%

Year Ended December 31, 2006 versus Year Ended December 31, 2005

	EBDA Increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Texas Intrastate Natural Gas Pipeline Group	$ 34.6	13%	$ (1,165.7)	(16)%
Rocky Mountain Pipeline Group	14.3	8%	27.9	11%
Red Cedar Gathering Company	4.3	13%	—	—
Casper and Douglas gas processing	2.9	30%	(6.4)	(6)%
All others	(1.4)	(21)%	2.5	167%
Intrasegment Eliminations	—	—	1.0	39%
Total Natural Gas Pipelines	$ 54.7	11%	$ (1,140.7)	(15)%

The segment's overall increases in earnings before depreciation, depletion and amortization expenses in both 2007 and 2006 were driven by strong year-over-year performances from our Texas intrastate natural gas pipeline group, which includes the operations of the following four natural gas pipeline systems: Kinder Morgan Tejas (including Kinder Morgan Border Pipeline), Kinder Morgan Texas Pipeline, Kinder Morgan North Texas Pipeline and our Mier-Monterrey Mexico Pipeline. Collectively, our Texas intrastate group serves the Texas Gulf Coast region by transporting, buying, selling, processing, treating and storing natural gas from multiple onshore and offshore supply sources.

The higher earnings in both 2007 and 2006, when compared to the respective prior years, were primarily due to higher sales margins on renewal and incremental contracts, increased transportation revenue from higher volumes and rates, greater value from natural gas storage activities, and higher natural gas processing margins. Our Texas intrastate natural gas pipeline group also benefited, in 2007, from higher sales of cushion gas, due to the termination of a storage facility lease, and from incremental natural gas storage revenues, due to a long-term contract with one of its largest customers that became effective April 1, 2007. Although natural gas sales volumes were down almost 5% in 2007 compared to 2006, natural gas transport volumes on our Texas intrastate systems increased 21% in 2007 and 5% in 2006, resulting in higher year-over-year transportation revenues. Because the group also buys and sells natural gas, the variances from period to period in both segment revenues and segment operating expenses (which include natural gas costs of sales) are due to changes in our intrastate group's average prices and volumes for natural gas purchased and sold.

The increase in earnings from our Casper and Douglas natural gas processing operations in 2007, when compared to 2006, was driven by an overall 6% increase in operating revenues. The increase was primarily attributable to higher natural gas liquids sales revenues, due to increases in both prices and volume. The 2006 increase in earnings was primarily related to incremental earnings associated with favorable hedge settlements from our natural gas gathering and processing operations. We benefited from comparative differences in hedge settlements associated with the rolling-off of older low price crude oil and propane positions at December 31, 2005.

The decrease in earnings in 2007 from our Rocky Mountain interstate natural gas pipeline group, which is comprised of Kinder Morgan Interstate Gas Transmission LLC, Trailblazer Pipeline Company LLC, TransColorado Gas Transmission Company LLC, and our current 51% equity investment in Rockies Express Pipeline LLC, resulted primarily from a $12.6 million decrease in equity earnings from our investment in Rockies Express. The decrease in earnings from Rockies Express, which began interim service in February 2006, reflected lower net income due primarily to incremental depreciation and interest expense allocable to a segment of the project that was placed in service in February 2007 and, until the completion of the Rockies Express-West project, had limited natural gas reservation revenues and volumes. Rockies Express-West is a 713-mile, 42-inch diameter natural gas pipeline that extends eastward from the Cheyenne Hub in Weld County, Colorado to Audrain County, Missouri. It has the capacity to transport up to 1.5 billion cubic feet of natural gas per day and it began interim service for up to 1.4 billion cubic feet per day on approximately 500 miles of line on January 12, 2008. Rockies Express-West is expected to become fully operational in mid-March 2008.

The $14.3 million (8%) increase in earnings in 2006, relative to 2005, from our Rocky Mountain interstate natural gas pipeline group was driven by a $10.2 million (10%) increase in earnings from our Kinder Morgan Interstate Gas Transmission system and a $3.8 million (10%) increase from TransColorado Pipeline. The increase from KMIGT was due largely to higher revenues earned in 2006 from both operational sales of natural gas and natural gas park and loan services. KMIGT's operational gas sales are primarily made possible by its collection of fuel in-kind pursuant to its transportation tariffs and recovery of storage cushion gas volumes. The increase from TransColorado was largely due to higher natural gas transmission revenues earned in 2006 compared to 2005, chiefly related to higher natural gas delivery volumes resulting from both system improvements and the successful negotiation of incremental firm transportation contracts. The pipeline system improvements were associated with an expansion, completed since the end of the first quarter of 2005, on the northern portion of the pipeline.

Both the drop, in 2007, and the increase, in 2006, in earnings before depreciation, depletion and amortization from our 49% equity investment in the Red Cedar Gathering Company were mainly due to higher prices on incremental sales of excess fuel gas and to higher natural gas gathering revenues in 2006, relative to both 2007 and 2005.

CO_2

	Year Ended December 31,		
	2007	**2006**	**2005**
	(In millions, except operating statistics)		
Revenues(a)	$ 824.1	$ 736.5	$ 657.6
Operating expenses(b)	(304.2)	(268.1)	(212.6)
Other income	—	—	—
Earnings from equity investments	19.2	19.2	26.3
Other, net-income (expense)	—	0.8	—
Income tax benefit (expense)	(2.1)	(0.2)	(0.4)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	$ 537.0	$ 488.2	$ 470.9
Carbon dioxide delivery volumes (Bcf)(c)	637.3	669.2	649.3
SACROC oil production (gross)(MBbl/d)(d)	27.6	30.8	32.1
SACROC oil production (net)(MBbl/d)(e)	23.0	25.7	26.7
Yates oil production (gross)(MBbl/d)(d)	27.0	26.1	24.2
Yates oil production (net)(MBbl/d)(e)	12.0	11.6	10.8
Natural gas liquids sales volumes (net)(MBbl/d)(e)	9.6	8.9	9.4
Realized weighted average oil price per Bbl(f)(g)	$ 36.05	$ 31.42	$ 27.36
Realized weighted average natural gas liquids price per Bbl(g)(h)	$ 52.91	$ 43.90	$ 38.98

(a) 2006 amount includes a $1.8 million loss (from a decrease in revenues) on derivative contracts used to hedge forecasted crude oil sales.

(b) 2007 and 2005 amounts include increases in expense associated with environmental liability adjustments of $0.2 million and $0.3 million, respectively.

(c) Includes Cortez, Central Basin, Canyon Reef Carriers, Centerline and Pecos pipeline volumes.

(d) Represents 100% of the production from the field. We own an approximate 97% working interest in the SACROC unit and an approximate 50% working interest in the Yates unit.

(e) Net to Kinder Morgan, after royalties and outside working interests.

(f) Includes all Kinder Morgan crude oil production properties.

(g) Hedge gains/losses for crude oil and natural gas liquids are included with crude oil.

(h) Includes production attributable to leasehold ownership and production attributable to our ownership in processing plants and third party processing agreements.

Our CO_2 segment consists of Kinder Morgan CO_2 Company, L.P. and its consolidated affiliates. The segment's primary businesses involve the production, marketing and transportation of both carbon dioxide (commonly called CO_2) and crude oil, and the production and marketing of natural gas and natural gas liquids.

Combined, the certain items described in the footnotes to the table above increased earnings before depreciation, depletion and amortization by $1.6 million in 2007, relative to 2006, and decreased earnings before depreciation, depletion and amortization by $1.5 million in 2006, relative to 2005. For each of the segment's two primary businesses, the following is information related to the remaining year-to-year increases and decreases in the segment's (i) earnings before depreciation, depletion and amortization (EBDA); and (ii) operating revenues:

Year Ended December 31, 2007 versus Year Ended December 31, 2006

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Sales and Transportation Activities	$ (9.3)	(5)%	$ (8.8)	(4)%
Oil and Gas Producing Activities	56.5	19%	81.6	14%
Intrasegment Eliminations	—	—	13.0	21%
Total CO_2	$ 47.2	10%	$ 85.8	12%

Year Ended December 31, 2006 versus Year Ended December 31, 2005

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Sales and Transportation Activities	$ 24.4	15%	$ 35.78	22%
Oil and Gas Producing Activities	(5.6)	(2)%	57.1	10%
Intrasegment Eliminations	—	—	(12.1)	(25)%
Total CO_2	$ 18.8	4%	$ 80.7	12%

The overall $47.2 million (10%) increase in segment earnings before depreciation, depletion and amortization expenses in 2007 versus 2006 was driven by higher earnings from the segment's oil and gas producing activities, which include its ownership interests in oil-producing fields and natural gas processing plants. The increase was largely due to higher oil production at the Yates oil field unit, higher realized average oil prices in 2007 relative to 2006, and higher earnings from natural gas liquids sales—due largely to increased recoveries at the Snyder, Texas gas plant and to an increase in our realized weighted average price per barrel.

The year-to-year decrease in earnings before depreciation, depletion and amortization from the segment's sales and transportation activities was primarily due to a decrease in carbon dioxide sales revenues, resulting mainly from lower average prices for carbon dioxide in 2007, and partly from a 3% drop in average carbon dioxide delivery volumes. The segment's average price received for all carbon dioxide sales decreased 9% in 2007, when compared to 2006. The decrease was mainly attributable to the expiration of a significantly high-priced sales contract in December 2006.

The segment's $18.8 million (4%) increase in earnings before depreciation, depletion and amortization in 2006 compared with 2005 was driven by higher earnings from the segment's carbon dioxide sales and transportation activities, largely due to higher revenues—from both carbon dioxide sales and deliveries, and from crude oil pipeline transportation. The overall increase in segment earnings before depreciation, depletion and amortization was partly offset by lower earnings from oil and gas producing activities and by lower equity earnings from the segment's 50% ownership interest in Cortez Pipeline Company.

The decrease in earnings from oil and gas producing activities in 2006 compared with 2005 was primarily due to higher combined operating expenses and to the previously disclosed drop in crude oil production at the SACROC oil field unit, discussed below. The higher operating expenses included higher field operating and maintenance expenses (including well workover expenses), higher property and severance taxes, and higher fuel and power expenses. The increases in expenses more than offset higher overall crude oil and natural gas plant product sales revenues, which increased primarily from higher realized sales prices and partly from higher crude oil production at the Yates field unit.

The overall increases in segment revenues in 2007 and 2006, when compared to respective prior years, were mainly due to higher revenues from the segment's oil and gas producing activities' crude oil sales and natural gas liquids sales. Combined, crude oil and plant product sales revenues increased $77.9 million (14%) in 2007 compared to 2006, and $63.9 million (12%) in 2006 compared to 2005.

The year-over-year increases in revenues from the sales of natural gas liquids were driven by favorable sales price variances—our realized weighted average price per barrel increased 21% in 2007 and 13% in 2006, when compared to the respective prior year. The year-over-year increases in revenues from the sales of crude oil reflected annual increases in our realized weighted average price per barrel of 15% in both 2007 and 2006, and although total crude oil sales volumes were relatively flat in 2006 compared to 2005, sales volumes decreased 6% in 2007 compared to 2006. Average gross oil production for 2007 was 27.0 thousand barrels per day at the Yates unit, up 3% from 2006, and 27.6 thousand barrels per day at SACROC, a decline of 10% versus 2006.

The year-to-year decline in crude oil production at the SACROC field unit is attributable to lower observed recoveries from recent project areas and due to an intentional slow down in development pace given this reduction in recoveries. For more information on our ownership interests in the net quantities of proved oil and gas reserves and our measures of discounted future net cash flows from oil and gas reserves, please see Note 20 to our consolidated financial statements included elsewhere in this report.

In addition, because our CO_2 segment is exposed to commodity price risk related to the price volatility of crude oil and natural gas liquids, we mitigate this risk through a long-term hedging strategy that is intended to generate more stable realized prices by using derivative contracts as hedges to the exposure of fluctuating expected future cash flows produced by changes in commodity sales prices. All of our hedge gains and losses for crude oil and natural gas liquids are included in our realized average price for oil. Had we not used energy derivative contracts to transfer commodity price risk, our crude oil sales prices would have averaged $69.63 per barrel in 2007, $63.27 per barrel in 2006 and $54.45 per barrel in 2005. For more information on our hedging activities, see Note 14 to our consolidated financial statements included elsewhere in this report.

Terminals

	Year Ended December 31,		
	2007	**2006**	**2005**
	(In millions, except operating statistics)		
Revenues	$ 963.7	$ 864.8	$ 699.3
Operating expenses(a)	(536.4)	(461.9)	(373.4)
Other income(b)	6.3	15.2	—
Earnings from equity investments	0.6	0.2	0.1
Other, net-income (expense)	1.0	2.1	(0.2)
Income tax benefit (expense)(c)	(19.2)	(12.3)	(11.2)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	$ 416.0	$ 408.1	$ 314.6
Bulk transload tonnage (MMtons)(d)	87.1	95.1	85.5
Liquids leaseable capacity (MMBbl)	47.5	43.5	42.4
Liquids utilization %	95.9%	96.3%	95.4%

(a) 2007 and 2005 amounts include increases in expense associated with environmental liability adjustments of $2.0 million and $3.5 million, respectively.2007 amount also includes a $25.0 million increase in expense from the settlement of certain litigation matters related to our Cora coal terminal, and a $1.2 million increase in expense associated with legal liability adjustments. 2006 amount includes a $2.8 million increase in expense related to hurricane clean-up and repair activities.

(b) 2007 and 2006 amounts include increases in income of $1.8 million and $15.2 million, respectively, from property casualty gains associated with the 2005 hurricane season.

(c) 2006 amount includes a $1.1 million increase in expense associated with hurricane expenses and casualty gain.

(d) Volumes for acquired terminals are included for 2007 and 2006.

Our Terminals segment includes the operations of our petroleum, chemical and other liquids terminal facilities (other than those included in our Products Pipelines segment), and all of our coal, petroleum coke, fertilizer, steel, ores and other dry-bulk material services facilities.

Combined, the certain items described in the footnotes to the table above decreased earnings before depreciation, depletion and amortization by $37.7 million in 2007, relative to 2006, and increased earnings before depreciation, depletion and amortization by $14.8 million in 2006, relative to 2005. The segment's remaining $45.6 million (11%) increase in earnings before depreciation, depletion and amortization expenses in 2007 compared with 2006, and its remaining $78.7 million (25%) increase in 2006 compared to 2005, were driven by a combination of internal expansions and strategic acquisitions completed since the end of 2005. We have made and continue to seek terminal acquisitions in order to gain access to new markets, to complement and/or enlarge our existing terminal operations, and to benefit from the economies of scale resulting from increases in storage, handling and throughput capacity.

In 2007, we invested approximately $158.9 million to acquire terminal assets and equity investments, and our significant terminal acquisitions since the fourth quarter of 2006 included the following:

- all of the membership interests of Transload Services, LLC, which provides material handling and steel processing services at 14 steel-related terminal facilities located in the Chicago metropolitan area and various cities in the United States, acquired November 20, 2006;
- all of the membership interests of Devco USA L.L.C., which includes a proprietary technology that transforms molten sulfur into solid pellets that are environmentally friendly and easier to transport, acquired December 1, 2006;
- the Vancouver Wharves bulk marine terminal, which includes five deep-sea vessel berths and terminal assets located on the north shore of the Port of Vancouver's main harbor. The assets include significant rail infrastructure, dry bulk and liquid storage, and material handling systems, and were acquired May 30, 2007; and
- the terminal assets and operations acquired from Marine Terminals, Inc., which are primarily involved in the handling and storage of steel and alloys and consist of two separate facilities located in Blytheville, Arkansas, and individual terminal facilities located in Decatur, Alabama, Hertford, North Carolina, and Berkley, South Carolina. The assets were acquired effective September 1, 2007.

Combined, these operations accounted for incremental amounts of earnings before depreciation, depletion and amortization of $31.2 million, revenues of $83.9 million, operating expenses of $53.2 million and equity earnings of $0.5 million, respectively, in 2007. All of the incremental amounts represent the earnings, revenues and expenses from the acquired terminals' operations during the additional months of ownership in 2007, and do not include increases or decreases during the same months we owned the assets in 2006.

In 2006, we also benefited significantly from the incremental contributions attributable to the bulk and liquids terminal businesses we acquired during 2005 and 2006. In addition to the two acquisitions acquired in the fourth quarter of 2006 and referred to above, these acquisitions included the following significant businesses:

- our Texas Petcoke terminals, located in and around the Ports of Houston and Beaumont, Texas, acquired effective April 29, 2005;

- three terminals acquired separately in July 2005: our Kinder Morgan Staten Island terminal, a dry-bulk terminal located in Hawesville, Kentucky and a liquids/dry-bulk facility located in Blytheville, Arkansas; and
- all of the ownership interests in General Stevedores, L.P., which operates a break-bulk terminal facility located along the Houston Ship Channel, acquired effective July 31, 2005.

Combined, these terminal acquisitions accounted for incremental amounts of earnings before depreciation, depletion and amortization of $33.5 million, revenues of $68.8 million and operating expenses of $35.3 million, respectively, in 2006. A majority of these increases in earnings, revenues and expenses were attributable to the inclusion of our Texas petroleum coke terminals, which we acquired from Trans-Global Solutions, Inc. on April 29, 2005 for an aggregate consideration of approximately $247.2 million. The primary assets acquired included facilities and railway equipment located at the Port of Houston, the Port of Beaumont and the TGS Deepwater terminal located on the Houston Ship Channel.

For all other terminal operations (those owned during identical periods in both 2007 and 2006), earnings before depreciation, depletion and amortization expenses increased $14.4 million (4%) in 2007, and $45.2 million (14%) in 2006, when compared to the respective prior years. The increases in earnings represent net changes in terminal results at various locations, but the year-over-year increase in 2007 compared to 2006 was largely due to higher earnings in 2007 from our two large Gulf Coast liquids terminal facilities located along the Houston Ship Channel in Pasadena and Galena Park, Texas. The two terminals continued to benefit from both recent expansions that have added new liquids tank and truck loading rack capacity since 2006, and incremental business from ethanol and biodiesel storage and transfer activity (for the entire segment, our expansion projects and acquisitions completed since the end of 2006 have increased our liquids terminals' leaseable capacity by 9%, more than offsetting a less than 1% drop in our overall utilization percentage). Higher earnings in 2007 also resulted from (i) the combined operations of our Argo and Chicago, Illinois liquids terminals, due to increased ethanol throughput and incremental liquids storage and handling business; (ii) our Texas Petcoke terminals, due largely to higher petroleum coke throughput volumes at our Port of Houston facility; and (iii) our Pier IX bulk terminal, located in Newport News, Virginia, largely due to a 19% year-to-year increase in coal transfer volumes and higher rail incentives.

The increase in earnings in 2006 compared to 2005 from terminals owned during both years included higher earnings in 2006 from (i) our Pasadena and Galena Park Gulf Coast liquids terminals, driven by higher revenues, in 2006, from new and incremental customer agreements, additional liquids tank capacity from capital expansions completed at our Pasadena terminal since the end of 2005, higher truck loading rack service fees, higher ethanol throughput, and incremental revenues from customer deficiency charges; (ii) our Shipyard River terminal, located in Charleston, South Carolina, due to higher revenues from liquids warehousing and coal and cement handling; (iii) our Texas Petcoke terminals, mainly resulting from an increase in petroleum coke handling volumes; and (iv) our Lower Mississippi River (Louisiana) terminals, primarily due to incremental earnings from our Amory and DeLisle Mississippi bulk terminals. Our Amory terminal began operations in July 2005. The higher earnings from our DeLisle terminal, which was negatively impacted by hurricane damage in 2005, was primarily due to higher bulk transfer revenues in 2006.

Trans Mountain

	Year Ended December 31,		
	2007	**2006(c)**	**2005**
	(In millions, except operating statistics)		
Revenues	$ 160.8	$ 137.8	$ —
Operating expenses	(65.9)	(53.3)	—
Other income (expense)(a)	(377.1)	0.9	—
Earnings from equity investments	—	—	—
Other, net-income (expense)	8.0	1.0	—
Income tax benefit (expense)	(19.4)	(9.9)	—
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments(b)	$ (293.6)	$ 76.5	$ —
Transport volumes (MMBbl)	94.4	83.7	—

(a) 2007 amount represents a goodwill impairment expense recorded by Knight in the first quarter of 2007.

(b) 2007 amount includes losses of $349.2 million for periods prior to our acquisition date of April 30, 2007, and a $1.3 million decrease in income from an oil loss allowance.

(c) 2006 amounts relate to periods prior to our acquisition date of April 30, 2007. See discussion below.

Our Trans Mountain segment includes the operations of the Trans Mountain Pipeline, which we acquired from Knight effective April 30, 2007. Trans Mountain transports crude oil and refined products from Edmonton, Alberta to marketing terminals and refineries in British Columbia and the state of Washington. An additional 35,000 barrel per day expansion that will increase capacity on the pipeline to approximately 300,000 barrels per day is currently under construction and is expected to be in service by late 2008.

According to the provisions of generally accepted accounting principles that prescribe the standards used to account for business combinations, due to the fact that our acquisition of Trans Mountain from Knight represented a transfer of assets between entities under common control, we initially recorded the assets and liabilities of Trans Mountain transferred to us from Knight at their carrying amounts in the accounts of Knight. Furthermore, our accompanying financial statements included in this report, and the information in the table above, reflect the results of operations for both 2007 and 2006 as though the transfer of Trans Mountain from Knight had occurred at the beginning of the period (January 1, 2006 for us).

After taking into effect the certain items described in the footnotes to the table above, the remaining increase in earnings before depreciation, depletion and amortization in 2007 versus 2006 totaled $56.9 million, and related entirely to our acquisition of Trans Mountain effective April 30, 2007.

Other

	Year Ended December 31, 2007	Year Ended December 31, 2006	Earnings increase/(decrease)	
	(In millions-income (expense), except percentages)			
General and administrative expenses(a)	$ (278.7)	$ (238.4)	$ (40.3)	(17)%
Interest expense, net of unallocable interest income(b)	(395.8)	(342.4)	(53.4)	(16)%
Unallocable income tax benefit (expense)	(4.6)	—	(4.6)	—
Minority interest(c)	(7.0)	(15.4)	8.4	55%
Total interest and corporate administrative expenses	$ (686.1)	$ (596.2)	$ (89.9)	(15)%

	Year Ended December 31, 2006	Year Ended December 31, 2005	Earnings increase/(decrease)	
	(In millions-income (expense), except percentages)			
General and administrative expenses(a)	$ (238.4)	$ (216.7)	$ (21.7)	(10)%
Interest expense, net of unallocable interest income(b)	(342.4)	(264.3)	(78.1)	(30)%
Minority interest(c)	(15.4)	(7.3)	(8.1)	(111)%
Total interest and corporate administrative expenses	$ (596.2)	$ (488.3)	$ (107.9)	(22)%

(a) 2007 amount includes (i) a $26.2 million increase in expense, allocated to us from Knight, associated with closing the going-private transaction. Knight Inc. was responsible for the payment of the costs resulting from this transaction; (ii) a $5.5 million expense related to Trans Mountain expenses for periods prior to our acquisition date of April 30, 2007; (iii) a $2.1 million expense due to the adjustment of certain insurance related liabilities; (iv) a $1.7 million increase in expense associated with the 2005 hurricane season; (v) a $1.5 million expense for certain Trans Mountain acquisition costs; and (vi) a $0.8 million expense related to the cancellation of certain commercial insurance policies. 2006 amount includes Trans Mountain expenses of $18.8 million, a $2.4 million increase in expense related to the cancellation of certain commercial insurance policies, and a $0.4 million decrease in expense related to the allocation of general and administrative expenses on hurricane related capital expenditures for the replacement and repair of assets. 2005 amount includes a $25.0 million expense for a litigation settlement reached between us and a former joint venture partner on our Kinder Morgan Tejas natural gas pipeline system, a cumulative $8.4 million expense related to settlements of environmental matters at certain of our operating sites located in the state of California, and a $3.0 million decrease in expense related to proceeds received in connection with the settlement of claims in the Enron Corp. bankruptcy proceeding.

(b) 2007 amount includes a $2.4 million increase in expense related to imputed interest on our Cochin Pipeline acquisition, and Trans Mountain expenses of $1.2 million for periods prior to our acquisition date of April 30, 2007. 2006 amount includes Trans Mountain expenses of $6.3 million.

(c) 2007 amount includes a $3.9 million decrease in expense, related to the minority interest effect from all of the 2007 items listed in footnotes (a) and (b). 2006 amount includes a $3.5 million increase in expense, primarily related to the minority interest effect from the property casualty insurance gain associated with the 2005 hurricane season.

Items not attributable to any segment include general and administrative expenses, unallocable interest income and income tax expense, interest expense and minority interest. Our general and administrative expenses include such items as salaries and employee-related expenses, payroll taxes, insurance, office supplies and rentals, unallocated litigation and environmental expenses, and shared corporate services—including accounting, information technology, human resources and legal services.

Compared to 2006, the certain items described in footnote (a) to the tables above increased our 2007 general and administrative expenses by $17.0 million. The remaining $23.3 million (11%) increase in expenses was largely due to (i) higher shared services expenses, which include legal, corporate secretary, tax, information technology and other shared services; and (ii) higher payroll-related expenses resulting from the acquisitions and incremental expansions we have made since the end of 2006.

Compared to 2005, the certain items described in footnote (a) decreased our 2006 general and administrative expenses by $9.6 million. The remaining $31.3 million (17%) increase in overall general and administrative expenses in 2006 compared to 2005 was primarily due to higher corporate service charges and higher corporate and employee-related insurance expenses in 2006. The increase in corporate services was largely due to higher corporate overhead expenses associated with the business operations we acquired since the end of 2005. The increase in insurance expenses was partly due to incremental expenses related to the cancellation of certain commercial insurance polices, as well as to the overall variability in year-to-year commercial property and medical insurance costs. Pursuant to certain provisions that gave us the right to cancel certain commercial policies prior to maturity, we took advantage of the opportunity to reinsure at lower rates.

Interest expense, net of unallocable interest income, totaled $395.8 million in 2007, $342.4 million in 2006 and $264.3 million in 2005. Compared to 2006, net interest expense decreased $2.7 million in 2007 due to the items described in footnote (b) to the tables above. The remaining $56.1 million (17%) increase in expense in 2007 compared to 2006 was due to both a 4% increase in average borrowing rates (the weighted average interest rate on all of our borrowings was approximately 6.40% during 2007 and 6.18% during 2006) and a 17% increase in average borrowings (excluding the market value of interest rate swaps). The increase in average borrowings was mainly due to capital spending in 2007, and the acquisition of external assets and businesses since the end of 2006.

We incurred incremental net interest expense of $6.3 million in 2006 due to the inclusion of Trans Mountain, and the remaining $71.8 million (27%) increase in expense in 2006 compared to 2005 was due to both higher average debt levels and higher effective interest rates. In 2006, average borrowings increased 10% and the weighted average interest rate on all of our borrowings increased 17%, when compared to 2005 (the weighted average interest rate on all of our borrowings was approximately6.18% during 2006 and 5.30% during 2005).

Generally, we initially fund both our capital spending (including payments for pipeline project construction costs) and our acquisition outlays from borrowings under our commercial paper program. From time to time, we issue senior notes in order to refinance our commercial paper borrowings. For more information on our capital expansion and acquisition expenditures, see "—Liquidity and Capital Resources—Investing Activities."

The year-to-year increases in our average borrowing rates in 2007 and 2006 reflect a general rise in variable interest rates since the end of 2005. We use interest rate swap agreements to help manage our interest rate risk. The swaps are contractual agreements we enter into in order to transform a portion of the underlying cash flows related to our long-term fixed rate debt securities into variable rate debt in order to achieve our desired mix of fixed and variable rate debt. However, in a period of rising interest rates, these swaps will result in period-to-period increases in our interest expense. For more information on our interest rate swaps, see Note 14 to our consolidated financial statements, included elsewhere in this report.

Liquidity and Capital Resources

Capital Structure

We attempt to maintain a conservative overall capital structure, with a long-term target mix of approximately 50% equity and 50% debt. In addition to our results of operations, our debt and capital balances are affected by our financing activities, as discussed below in "—Financing Activities." The following table illustrates the sources of our invested capital (dollars in millions):

	December 31,		
	2007	2006	2005
Long-term debt, excluding market value of interest rate swaps	$ 6,455.9	$ 4,384.3	$ 5,220.9
Minority interest	54.2	60.2	42.3
Partners' capital, excluding accumulated other comprehensive loss	5,712.3	5,814.4	4,693.5
Total capitalization	12,222.4	10,258.9	9,956.7
Short-term debt, less cash and cash equivalents	551.3	1,352.4	(12.1)
Total invested capital	$ 12,773.7	$ 11,611.3	$ 9,944.6
Capitalization:			
Long-term debt, excluding market value of interest rate swaps	52.8%	42.7%	52.4%
Minority interest	0.5%	0.6%	0.4%
Partners' capital, excluding accumulated other comprehensive loss	46.7%	56.7%	47.2%
	100.0%	100.0%	100.0%
Invested Capital:			
Total debt, less cash and cash equivalents and excluding market value of interest rate swaps	54.9%	49.4%	52.4%
Partners' capital and minority interest, excluding accumulated other comprehensive loss	45.1%	50.6%	47.6%
	100.0%	100.0%	100.0%

Our primary cash requirements, in addition to normal operating expenses, are debt service, sustaining capital expenditures, expansion capital expenditures and quarterly distributions to our common unitholders, Class B unitholders and general partner. In addition to utilizing cash generated from operations, we could meet our cash requirements for expansion capital expenditures through borrowings under our credit facility, issuing short-term commercial paper, long-term notes or additional common units or the proceeds from purchases of additional i-units by KMR with the proceeds from issuances of KMR shares.

In general, we expect to fund:

- cash distributions and sustaining capital expenditures with existing cash and cash flows from operating activities;
- expansion capital expenditures and working capital deficits with retained cash (resulting from including i-units in the determination of cash distributions per unit but paying quarterly distributions on i-units in additional i-units rather than cash), additional borrowings, the issuance of additional common units or the proceeds from purchases of additional i-units by KMR;
- interest payments with cash flows from operating activities; and
- debt principal payments with additional borrowings, as such debt principal payments become due, or by the issuance of additional common units or the proceeds from purchases of additional i-units by KMR.

As a publicly traded limited partnership, our common units are attractive primarily to individual investors, although such investors represent a small segment of the total equity capital market. We believe that some institutional investors prefer shares of KMR over our common units due to tax and other regulatory considerations. We are able to access this segment of the capital market through KMR's purchases of i-units issued by us with the proceeds from the sale of KMR shares to institutional investors.

As part of our financial strategy, we try to maintain an investment-grade credit rating, which involves, among other things, the issuance of additional limited partner units in connection with our acquisitions and internal growth activities in order to maintain acceptable financial ratios.

On May 30, 2006, Standard & Poor's Rating Services and Moody's Investors Service each placed our ratings on credit watch pending the resolution of KMI's going-private transaction. On January 5, 2007, in anticipation of the buyout closing, S&P downgraded us one level to BBB and removed our rating from credit watch with negative implications. Currently, our debt credit rating is still rated BBB by S&P. As previously noted by Moody's in its credit opinion dated November 15, 2006, it downgraded our credit rating from Baa1 to Baa2 on May 30, 2007, following the closing of the going-private transaction. Additionally, our rating was downgraded by Fitch Ratings from BBB+ to BBB on April 11, 2007.

Short-term Liquidity

We employ a centralized cash management program that essentially concentrates the cash assets of our operating partnerships and their subsidiaries in joint accounts for the purpose of providing financial flexibility and lowering the cost of borrowing. Our centralized cash management program provides that funds in excess of the daily needs of our operating partnerships and their subsidiaries are concentrated, consolidated, or otherwise made available for use by other entities within our consolidated group. We place no restrictions on the ability to move cash between entities, payment of inter-company balances or the ability to upstream dividends to parent companies other than restrictions that may be contained in agreements governing the indebtedness of those entities. However, our cash and the cash of our subsidiaries is not concentrated into accounts of Knight or any company not in our consolidated group of companies, and Knight has no rights with respect to our cash except as permitted pursuant to our partnership agreement.

Furthermore, certain of our operating subsidiaries are subject to FERC enacted reporting requirements for oil and natural gas pipeline companies that participate in cash management programs. FERC-regulated entities subject to these rules must, among other things, place their cash management agreements in writing, maintain current copies of the documents authorizing and supporting their cash management agreements, and file documentation establishing the cash management program with the FERC.

Our principal sources of short-term liquidity are (i) our $1.85 billion five-year senior unsecured revolving credit facility that matures August 18, 2010; (ii) our $1.85 billion short-term commercial paper program (which is supported by our bank credit facility, with the amount available for borrowing under our credit facility being reduced by our outstanding commercial paper borrowings); and (iii) cash from operations (discussed following).

Borrowings under our five-year credit facility can be used for general partnership purposes and as a backup for our commercial paper program. The facility can be amended to allow for borrowings up to $2.1 billion. There were no borrowings under our credit facility as of December 31, 2007. As of December 31, 2007, we had $589.1 million of commercial paper outstanding.

We provide for additional liquidity by maintaining a sizable amount of excess borrowing capacity related to our commercial paper program and long-term revolving credit facility. After reduction for our outstanding commercial paper borrowings and letters of credit, the remaining available borrowing capacity under our bank credit facility was $723.1 million as of December 31, 2007. As of December 31, 2007, our outstanding short-term debt was $610.2 million. Currently, we believe our liquidity to be adequate. For more information on our commercial paper program and our credit facility, see Note 9 to our consolidated financial statements included elsewhere in this report.

Long-term Financing

In addition to our principal sources of short-term liquidity listed above, we could meet our cash requirements (other than distributions to our common unitholders, Class B unitholders and general partner) through issuing long-term notes or additional common units, or the proceeds from purchases of additional i-units by KMR with the proceeds from issuances of KMR shares.

We are subject, however, to changes in the equity and debt markets for our limited partner units and long-term notes, and there can be no assurance we will be able or willing to access the public or private markets for our limited partner units and/or long-term notes in the future. If we were unable or unwilling to issue additional limited partner units, we would be required to either restrict potential future acquisitions or pursue other debt financing alternatives, some of which could involve higher costs or negatively affect our credit ratings. Our ability to access the public and private debt markets is affected by our credit ratings. See "—Capital Structure" above for a discussion of our credit ratings.

Equity Issuances

On May 17, 2007, KMR issued 5,700,000 of its shares in a public offering at a price of $52.26 per share. The net proceeds from the offering were used by KMR to buy additional i-units from us, and we received net proceeds of $297.9 million for the issuance of 5,700,000 i-units.

On December 5, 2007, we completed a public offering of 7,130,000 of our common units, including common units sold pursuant to the underwriters' over-allotment option, at a price of $48.09 per unit, less commissions and underwriting expenses. We received net proceeds of $342.9 million for the issuance of these 7,130,000 common units.

We used the proceeds from each of these two equity issuances to reduce the borrowings under our commercial paper program. In addition, pursuant to our purchase and sale agreement with Trans-Global Solutions, Inc., we issued 266,813 common units in May 2007 to TGS to settle a purchase price liability related to our acquisition of bulk terminal operations from TGS in April 2005. As agreed between TGS and us, the units were valued at $15.0 million.

On February 12, 2008, we completed an additional offering of 1,080,000 of our common units at a price of $55.65 per unit in a privately negotiated transaction with two investors. We received net proceeds of $60.1 million for the issuance of these 1,080,000 common units, and we used the proceeds to reduce the borrowings under our commercial paper program.

Debt Issuances

From time to time we issue long-term debt securities. All of our long-term debt securities issued to date, other than those issued under our long-term revolving credit facility or those issued by our subsidiaries and operating partnerships, generally have the same terms except for interest rates, maturity dates and prepayment premiums. All of our outstanding debt securities are unsecured obligations that rank equally with all of our other senior debt obligations; however, a modest amount of secured debt has been incurred by some of our operating partnerships and subsidiaries. Our fixed rate notes provide that we may redeem the notes at any time at a price equal to 100% of the principal amount of the notes plus accrued interest to the redemption date plus a make-whole premium.

During 2007, we completed three separate public offerings of senior notes. We received proceeds, net of underwriting discounts and commissions, as follows:

- $992.8 million from a January 30, 2007 public offering of a total of $1.0 billion in principal amount of senior notes, consisting of $600 million of 6.00% notes due February 1, 2017, and $400 million of 6.50% notes due February 1, 2037;
- $543.9 million from a June 21, 2007 public offering of $550 million in principal amount of 6.95% senior notes due January 15, 2038; and
- $497.8 million from an August 28, 2007 public offering of $500 million in principal amount of 5.85% senior notes due September 15, 2012.

We used the proceeds from each of these three debt offerings to reduce the borrowings under our commercial paper program. In addition, on August 15, 2007, we repaid $250 million of 5.35% senior notes that matured on that date. As of December 31, 2007, our total liability balance due on the various series of our senior notes was $6,288.8 million, and the total liability balance due on the various borrowings of our operating partnerships and subsidiaries was $188.2 million. For additional information regarding our debt securities, see Note 9 to our consolidated financial statements included elsewhere in this report.

On February 12, 2008, we completed a public offering of senior notes. We issued a total of $900 million in principal amount of senior notes, consisting of $600 million of 5.95% notes due February 15, 2018, and $300 million of 6.95% notes due January 15, 2038. We received proceeds from the issuance of the notes, after underwriting discounts and commissions, of approximately $894.1 million, and we used the proceeds to reduce the borrowings under our commercial paper program.

Capital Requirements for Recent Transactions

During 2007, our cash outlays for the acquisition of assets and investments totaled $713.3 million. We utilized our commercial paper program to fund our 2007 acquisitions. We then reduced our short-term borrowings with the proceeds from our issuances of additional limited partnership units and senior notes, as described above. We intend to refinance the remainder of our current short-term debt and any additional short-term debt incurred during 2008 through a combination of long-term debt, equity and the issuance of additional commercial paper to replace maturing commercial paper borrowings.

We are committed to maintaining a cost effective capital structure and we intend to finance new acquisitions using a mix of approximately 50% equity financing and 50% debt financing. For more information on our capital requirements during 2007 in regard to our acquisition expenditures, see Note 3 to our consolidated financial statements included elsewhere in this report.

Off Balance Sheet Arrangements

We have invested in entities that are not consolidated in our financial statements. As of December 31, 2007, our obligations with respect to these investments, as well as our obligations with respect to a letter of credit, are summarized below (dollars in millions):

Entity	**Investment Type**	**Our Ownership Interest**	**Remaining Interest(s) Ownership**	**Total Entity Assets(5)**	**Total Entity Debt**	**Our Contingent Share of Entity Debt(6)**
Cortez Pipeline Company	General Partner	50%	(1)	$ 79.9	$ 157.3	$ 78.7(2)
West2East Pipeline LLC(3)	Limited Liability	51%	ConocoPhillips and Sempra Energy	$ 2,730.2	$ 2,225.4	$ 1,135.0
Nassau County, Florida Ocean Highway And Port Authority (4)	N/A	N/A	Nassau County, Florida Ocean Highway and Port Authority	N/A	N/A	$ 22.5

(1) The remaining general partner interests are owned by ExxonMobil Cortez Pipeline, Inc., an indirect wholly-owned subsidiary of Exxon Mobil Corporation and Cortez Vickers Pipeline Company, an indirect subsidiary of M.E. Zuckerman Energy Investors Incorporated.

(2) We are severally liable for our percentage ownership share (50%) of the Cortez Pipeline Company debt. As of December 31, 2007, Shell Oil Company shares our several guaranty obligations jointly and severally for $64.3 million of Cortez's debt balance; however, we are obligated to indemnify Shell for the liabilities it incurs in connection with such guaranty. Accordingly, as of December 31, 2007 we have a letter of credit in the amount of $37.5 million issued by JP Morgan Chase, in order to secure our indemnification obligations to Shell for 50% of the Cortez debt balance of $64.3 million.

Further, pursuant to a Throughput and Deficiency Agreement, the partners of Cortez Pipeline Company are required to contribute capital to Cortez in the event of a cash deficiency. The agreement contractually supports the financings of Cortez Capital Corporation, a wholly-owned subsidiary of Cortez Pipeline Company, by obligating the partners of Cortez Pipeline to fund cash deficiencies at Cortez Pipeline, including anticipated deficiencies and cash deficiencies relating to the repayment of principal and interest on the debt of Cortez Capital Corporation. The partners' respective parent or other companies further severally guarantee the obligations of the Cortez Pipeline owners under this agreement.

(3) West2East Pipeline LLC is a limited liability company and is the sole owner of Rockies Express Pipeline LLC. As of December 31, 2007, the remaining limited liability member interests in West2East Pipeline LLC are owned by ConocoPhillips (24%) and Sempra Energy (25%). We owned a 66 2/3% ownership interest in West2East Pipeline LLC from October 21, 2005 until June 30, 2006, and we included its results in our consolidated financial statements until June 30, 2006. On June 30, 2006, our ownership interest was reduced to 51%, West2East Pipeline LLC was deconsolidated, and we subsequently accounted for our investment under the equity method of accounting. Upon completion of the pipeline, our ownership percentage is expected to be reduced to 50%.

(4) Arose from our Vopak terminal acquisition in July 2001. Nassau County, Florida Ocean Highway and Port Authority is a political subdivision of the state of Florida. During 1990, Ocean Highway and Port Authority issued its Adjustable Demand Revenue Bonds in the aggregate principal amount of $38.5 million for the purpose of constructing certain port improvements located in Fernandino Beach, Nassau County, Florida. A letter of credit was issued as security for the Adjustable Demand Revenue Bonds and was guaranteed by the parent company of Nassau Terminals LLC, the operator of the port facilities. In July 2002, we acquired Nassau Terminals LLC and became guarantor under the letter of credit agreement. In December 2002, we issued a $28 million letter of credit under our credit facilities and the former letter of credit guarantee was terminated. As of December 31, 2007, the face amount of this letter of credit outstanding under our credit facility was $22.5 million. Principal payments on the bonds are made on the first of December each year and reductions are made to the letter of credit.

(5) Principally property, plant and equipment.

(6) Represents the portion of the entity's debt that we may be responsible for if the entity cannot satisfy the obligation.

We account for our investments in Cortez Pipeline Company and West2East Pipeline LLC under the equity method of accounting. For the year ended December 31, 2007, our share of earnings, based on our ownership percentage and before amortization of excess investment cost was $19.2 million from Cortez Pipeline Company and a loss of $12.4 million from West2East Pipeline LLC. Additional information regarding the nature and business purpose of these investments is included in Notes 7 and 9 to our consolidated financial statements included elsewhere in this report.

Summary of Certain Contractual Obligations

	Amount of Commitment Expiration per Period				
	Total	**1 Year or Less**	**2-3 Years**	**4-5 Years**	**After 5 Years**
			(In millions)		
Contractual Obligations:					
Commercial paper outstanding	$ 589.1	$ 589.1	$ —	$ —	$ —
Other debt borrowings-principal payments	6,488.2	21.1	537.0	1,681.4	4,248.7
Interest payments(a)	5,947.2	443.7	788.0	633.9	4,081.6
Lease obligations(b)	130.7	31.7	42.7	28.1	28.2
Pension and post-retirement welfare plans(c)	62.1	4.6	9.7	10.9	36.9
Other obligations(d)	146.1	44.9	84.1	17.1	—
Total	$ 13,363.4	$ 1,135.1	$ 1,461.5	$ 2,371.4	$ 8,395.4
Other commercial commitments:					
Standby letters of credit(e)	$ 672.4	$ 634.9	$ —	$ —	$ 37.5
Capital expenditures(f)	$ 250.5	$ 250.5	—	—	—

(a) Interest payment obligations exclude adjustments for interest rate swap agreements.

(b) Represents commitments for capital leases, including interest, and operating leases.

(c) Represents expected benefit payments from pension and post-retirement welfare plans as of December 31, 2007.

(d) Consist of payments due under carbon dioxide take-or-pay contracts.

(e) The $672.4 million in letters of credit outstanding as of December 31 2007 consisted of the following: (i) a combined $298.0 million in three letters of credit supporting our hedging of energy commodity price risks; (ii) a $100 million letter of credit that supports certain proceedings with the California Public Utilities Commission involving refined products tariff charges

on the intrastate common carrier operations of our Pacific operations' pipelines in the state of California; (iii) a combined $58.3 million in ten letters of credit supporting our Trans Mountain pipeline system operations; (iv) a $37.5 million letter of credit supporting our indemnification obligations on the Series D note borrowings of Cortez Capital Corporation; (v) our $30.3 million guarantee under letters of credit totaling $45.5 million supporting our International Marine Terminals Partnership Plaquemines, Louisiana Port, Harbor, and Terminal Revenue Bonds; (vi) a $25.3 million letter of credit supporting our Kinder Morgan Liquids Terminals LLC New Jersey Economic Development Revenue Bonds; (vii) a $24.1 million letter of credit supporting our Kinder Morgan Operating L.P. "B" tax-exempt bonds; (viii) a $22.5 million letter of credit supporting Nassau County, Florida Ocean Highway and Port Authority tax-exempt bonds; (ix) a $19.9 million letter of credit supporting the construction of our Kinder Morgan Louisiana Pipeline; (x) a $15.5 million letter of credit supporting our pipeline and terminal operations in Canada; (xi) a $5.4 million letter of credit supporting our Arrow Terminals, L.P. Illinois Development Revenue Bonds; and (xii) a combined $20.4 million in eight letters of credit supporting environmental and other obligations of us and our subsidiaries.

(f) Represents commitments for the purchase of plant, property and equipment as of December 31, 2007.

Operating Activities

Net cash provided by operating activities was $1,741.8 million in 2007, versus $1,363.9 million in 2006. The overall year-to-year increase of $377.9 million (28%) in cash flow from operations principally consisted of:

- a $159.1 million increase in cash attributable to changes in the reserves related to the legal fees, transportation rate cases and other litigation liabilities of our pipeline and terminal operations (consisting of an incremental $140.0 million non-cash operating expense accrued in 2007, and payments of $19.1 million made in June 2006 to certain shippers on our Pacific operations' pipelines). The expense was associated with a liability adjustment made in December 2007, and the payments related to a settlement agreement reached in May 2006 that resolved certain challenges by complainants with regard to delivery tariffs and gathering enhancement fees at our Pacific operations' Watson Station, located in Carson, California;

- a $139.1 million increase in cash inflows relative to changes in (i) other non-current assets and liabilities, including, among other things, incremental transportation and dock prepayments received from pipeline customers (due primarily to timing differences); and (ii) other incremental non-cash expenses, including higher non-cash operating expenses in 2007 associated with environmental liability adjustments, and higher non-cash general and administrative expenses related to the activities required to complete KMI's going-private transaction (with regard to the going-private transaction expenses, we were required to recognize the full amounts allocated to us from Knight as expense on our income statement; however, due to the fact that almost all of the allocated expenses were associated with the acceleration of cashouts of grants of both KMI restricted stock and options on KMI stock, we were not responsible for paying these buyout expenses, and accordingly, recognized the unpaid amount as both a contribution to "Partners' Capital" and an increase to "Minority interest" on our balance sheet);

- a $95.1 million increase in cash inflows relative to net changes in working capital items, mainly due to timing differences that resulted in higher 2007 net cash inflows from the collection and payment of trade and related party receivables and payables, and from lower payments on accrued tax and interest liabilities; and

- a $51.6 million decrease in cash from overall lower partnership income—net of the following non-cash items: (i) depreciation, depletion and amortization expenses; (ii) gains and losses on property sales and casualty indemnifications; (iii) earnings from equity investees; and (iv) a $377.1 million goodwill impairment charge recognized in the first quarter of 2007. The increases and decreases in our partnership income in 2007 compared to 2006 are discussed above in "—Results of Operations."

Investing Activities

Net cash used in investing activities was $2,428.5 million for the year ended December 31, 2007, compared to $1,501.9 million for the prior year. The $926.6 million (62%) overall increase in funds utilized in investing activities was primarily attributable to the following:

- a $326.1 million increase due to higher expenditures made for strategic business acquisitions. In 2007, our acquisition outlays for assets and investments totaled $713.3 million, primarily consisting of $549.1 million for net payments made to Knight for our acquisition of the Trans Mountain pipeline system, $100.3 million for the acquisition of bulk terminal assets from Marine Terminals, Inc., and $38.8 million for the purchase of the Vancouver Wharves bulk marine terminal. In 2006, our acquisition outlays totaled $387.2 million, primarily consisting of $244.6 million for the acquisition of Entrega Gas Pipeline LLC and $89.1 million for the acquisition of bulk, liquids and refined products terminal operations and related assets. Both our 2007 and 2006 acquisition expenditures are discussed more fully in Note 3 to our consolidated financial statements included elsewhere in this report;

- a $509.5 million increase from higher capital expenditures—largely due to increased investments undertaken to expand and improve our bulk and liquids terminalling operations, and our Trans Mountain pipeline system. Our sustaining capital expenditures, defined as capital expenditures that do not increase the capacity of an asset, totaled $152.6 million in 2007 and $125.5 million in 2006. The above amounts do not include the sustaining capital expenditures of our Trans Mountain business segment for periods prior to our acquisition date of April 30, 2007. Additionally, our forecasted expenditures for sustaining capital expenditures for 2008 are approximately $196.2 million. All of our capital expenditures, with the exception of sustaining capital expenditures, are discretionary;

- a $273.6 million increase from incremental contributions to equity investments in 2007, largely driven by incremental investments of $202.7 million and $61.6 million, respectively, for our proportionate share of construction costs of the Rockies Express and Midcontinent Express pipelines; and

- a $231.8 million decrease in cash used due to higher net proceeds received from the sales of property, plant and equipment and other net assets (net of salvage and removal costs). The increase from sales proceeds in 2007 versus 2006 was driven by the approximately $298.6 million we received for the sale of our North System operations in October 2007. In April 2006, we received $42.5 million from Momentum Energy Group, LLC for the combined sale of our Douglas natural gas gathering system and Painter Unit fractionation facility, and in the first half of 2006, we received $27.1 million from the sale of certain oil and gas properties originally acquired from Journey Acquisition – I, L.P. and Journey 2000, L.P.

Financing Activities

Net cash provided by financing activities amounted to $735.7 million in 2007; while in the prior year, our financing activities provided net cash of $132.4 million. The $603.3 million (456%) overall increase in cash inflows provided by financing activities was primarily due to:

- a $334.5 million increase from overall debt financing activities—which include our issuances and payments of debt and our debt issuance costs. The year-to-year increase in cash from financing activities was primarily due to (i) a $1,784.5 million net increase in cash inflows from the issuances and payments of senior notes in 2007; and (ii) a $1,453.6 million decrease in cash from lower overall net commercial paper borrowings in 2007, relative to 2006.

  The decrease in commercial paper borrowings includes a decrease of $412.5 million from borrowings under the commercial paper program of Rockies Express Pipeline LLC in the first half of 2006. We held and consolidated a 66 2/3% ownership interest in Rockies Express Pipeline LLC until June 30, 2006. Effective June 30, 2006, ConocoPhillips exercised its option to acquire a 25% ownership interest in West2East Pipeline LLC (and its subsidiary Rockies Express Pipeline LLC), and West2East Pipeline LLC was then deconsolidated and accounted for under the equity method of accounting. Generally accepted accounting principles required us to include its cash inflows and outflows in our consolidated statement of cash flows for the six months ended June 30, 2006; however, following the change from full consolidation to the equity method, Rockies Express' debt balances were not included in our consolidated balance sheet as of or subsequent to June 30, 2006.

  The $1,784.5 million increase in cash inflows from changes in senior notes outstanding was associated with public debt offerings completed on January 30, 2007, June 21, 2007 and August 28, 2007. On these dates, we completed offerings of $1.0 billion, $550 million and $500 million, respectively, in principal amount of senior notes in four separate series: (i) $600 million of 6.00% notes due February 1, 2017; (ii) $400 million of 6.50% notes due February 1, 2037; (iii) $550 million of 6.95% notes due January 15, 2038; and (iv) $500 million of 5.85% notes due September 15, 2012. Combined, we received proceeds, net of underwriting discounts and commissions, of $2,034.5 million from these long-term debt offerings and we used the proceeds from each of these offerings to reduce the borrowings under our commercial paper program. In addition, on August 15, 2007, we repaid $250 million of 5.35% senior notes that matured on that date;

- a $392.4 million increase from overall equity financing activities—which include our issuances of limited partner units. In May 2007, we received proceeds of $297.9 million, after commissions and underwriting expenses, for our issuance of 5,700,000 i-units to KMR, and in December 2007, we received net proceeds of $342.9 million from a public offering of 7,130,000 common units. In 2006, we received proceeds of $248.4 million from the issuance of additional common units, primarily related to our August 2006 public offering of 5,750,000 of our common units at a price of $44.80, less commissions and underwriting expenses. We used the proceeds from each of these equity issuances to reduce the borrowings under our commercial paper program; and

- a $100.9 million decrease from lower contributions from minority interests—principally due to contributions of $104.2 million received in 2006 from Sempra Energy with regard to their ownership interest in Rockies Express. The contributions from Sempra included an $80.0 million contribution for its 33 1/3% share of the purchase price of Entrega Gas Pipeline LLC, discussed above in "—Investing Activities."

Partnership Distributions

Our partnership agreement requires that we distribute 100% of "Available Cash," as defined in our partnership agreement, to our partners within 45 days following the end of each calendar quarter in accordance with their respective percentage interests. Available Cash consists generally of all of our cash receipts, including cash received by our operating partnerships and net reductions in reserves, less cash disbursements and net additions to reserves and amounts payable to the former general partner of SFPP, L.P. in respect of its remaining 0.5% interest in SFPP.

Our general partner is granted discretion by our partnership agreement, which discretion has been delegated to KMR, subject to the approval of our general partner in certain cases, to establish, maintain and adjust reserves for future operating expenses, debt service, maintenance capital expenditures, rate refunds and distributions for the next four quarters. These reserves are not restricted by magnitude, but only by type of future cash requirements with which they can be associated. When KMR determines our quarterly distributions, it considers current and expected reserve needs along with current and expected cash flows to identify the appropriate sustainable distribution level. For 2007, 2006 and 2005, we distributed approximately 100%, 103% and 101%, respectively, of the total of cash receipts less cash disbursements (calculations assume that KMR unitholders received cash). The difference between these numbers and 100% of distributable cash flow reflects net changes in reserves.

Our general partner and owners of our common units and Class B units receive distributions in cash, while KMR, the sole owner of our i-units, receives distributions in additional i-units. We do not distribute cash to i-unit owners but instead retain the cash for use in our business. However, the cash equivalent of distributions of i-units is treated as if it had actually been distributed for purposes of determining the distributions to our general partner. Each time we make a distribution, the number of i-units owned by KMR and the percentage of our total units owned by KMR increase automatically under the provisions of our partnership agreement.

Available cash is initially distributed 98% to our limited partners and 2% to our general partner. These distribution percentages are modified to provide for incentive distributions to be paid to our general partner in the event that quarterly distributions to unitholders exceed certain specified targets.

Available cash for each quarter is distributed:

- first, 98% to the owners of all classes of units pro rata and 2% to our general partner until the owners of all classes of units have received a total of $0.15125 per unit in cash or equivalent i-units for such quarter;

- second, 85% of any available cash then remaining to the owners of all classes of units pro rata and 15% to our general partner until the owners of all classes of units have received a total of $0.17875 per unit in cash or equivalent i-units for such quarter;

- third, 75% of any available cash then remaining to the owners of all classes of units pro rata and 25% to our general partner until the owners of all classes of units have received a total of $0.23375 per unit in cash or equivalent i-units for such quarter; and

- fourth, 50% of any available cash then remaining to the owners of all classes of units pro rata, to owners of common units and Class B units in cash and to owners of i-units in the equivalent number of i-units, and 50% to our general partner.

Incentive distributions are generally defined as all cash distributions paid to our general partner that are in excess of 2% of the aggregate value of cash and i-units being distributed. Our general partner's incentive distribution that we declared for 2007 was $611.9 million, while the incentive distribution paid to our general partner during 2007 was $559.6 million. The difference between declared and paid distributions is due to the fact that our distributions for the fourth quarter of each year are declared and paid in the first quarter of the following year. In addition, our general partner waived $20.1 million of its 2006 incentive distribution for the fourth quarter of 2006, which was paid in the first quarter of 2007, in order to fund the annual bonus for employees.

On February 14, 2008, we paid a quarterly distribution of $0.92 per unit for the fourth quarter of 2007. This distribution was 11% greater than the $0.83 distribution per unit we paid for both the fourth quarter of 2006 and the first quarter of 2007. We paid this distribution in cash to our common unitholders and to our Class B unitholders. KMR, our sole i-unitholder, received additional i-units based on the $0.92 cash distribution per common unit. We believe that future operating results will continue to support similar levels of quarterly cash and i-unit distributions; however, no assurance can be given that future distributions will continue at such levels.

Litigation and Environmental

As of December 31, 2007, we have recorded a total reserve for environmental claims, without discounting and without regard to anticipated insurance recoveries, in the amount of $92.0 million. In addition, we have recorded a receivable of $37.8 million for expected cost recoveries that have been deemed probable. The reserve is primarily established to address and clean up soil and ground water impacts from former releases to the environment at facilities we have acquired or accidental spills or releases at facilities that we own. Reserves for each project are generally established by reviewing existing documents, conducting interviews and performing site inspections to determine the overall size and impact to the environment. Reviews are made on a quarterly basis to determine the status of the cleanup and the costs associated with the effort. In assessing environmental risks in conjunction with proposed acquisitions, we review records relating to environmental issues, conduct site inspections, interview employees, and, if appropriate, collect soil and groundwater samples. As of December 31, 2006, our total reserve for environmental claims, without discounting and without regard to anticipated insurance recoveries, amounted to $64.2 million.

Additionally, as of December 31, 2007, we have recorded a total reserve for legal fees, transportation rate cases and other litigation liabilities in the amount of $247.9 million. The reserve is primarily related to various claims from lawsuits arising from our Pacific operations, and the contingent amount is based on both the circumstances of probability and reasonability of dollar estimates. We regularly assess the likelihood of adverse outcomes resulting from these claims in order to determine the adequacy of our liability provision, and in December 2007, we recorded a non-cash increase in operating expense of $140.0 million related to our litigation matters. As of December 31, 2006, our total reserve for legal fees, transportation rate cases and other litigation liabilities amounted to $112.0 million.

Though no assurance can be given, we believe we have established adequate environmental and legal reserves such that the resolution of pending environmental matters and litigation will not have a material adverse impact on our business, cash flows, financial position or results of operations.

Pursuant to our continuing commitment to operational excellence and our focus on safe, reliable operations, we have implemented, and intend to implement in the future, enhancements to certain of our operational practices in order to strengthen our environmental and asset integrity performance. These enhancements have resulted and may result in higher operating costs and sustaining capital expenditures; however, we believe these enhancements will provide us the greater long term benefits of improved environmental and asset integrity performance.

Please refer to Notes 16 and 17 of our consolidated financial statements included elsewhere in this report for additional information regarding pending litigation and environmental matters, respectively.

Regulation

The Pipeline Safety Improvement Act of 2002 requires pipeline companies to perform integrity tests on natural gas transmission pipelines that exist in high population density areas that are designated as High Consequence Areas. Pipeline companies are required to perform the integrity tests within ten years of December 17, 2002, the date of enactment, and must perform subsequent integrity tests on a seven year cycle. At least 50% of the highest risk segments must be tested within five years of the enactment date. The risk ratings are based on numerous factors, including the population density in the geographic regions served by a particular pipeline, as well as the age and condition of the pipeline and its protective coating. Testing will consist of hydrostatic testing, internal electronic testing, or direct assessment of the piping. A similar integrity management rule for refined petroleum products pipelines became effective May 29, 2001. All baseline assessments for products pipelines must be completed by March 31, 2008 and we expect to meet this deadline. We have included all incremental expenditures estimated to occur during 2008 associated with the Pipeline Safety Improvement Act of 2002 and the integrity management of our products pipelines in our 2008 budget and capital expenditure plan.

Please refer to Note 17 to our consolidated financial statements included elsewhere in this report for additional information regarding regulatory matters.

Recent Accounting Pronouncements

Please refer to Note 18 to our consolidated financial statements included elsewhere in this report for information concerning recent accounting pronouncements.

Information Regarding Forward-Looking Statements

This filing includes forward-looking statements. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. They use words such as "anticipate," "believe," "intend," "plan," "projection," "forecast," "strategy," "position," "continue," "estimate," "expect," "may," or the negative of those terms or other variations of them or comparable terminology. In particular, statements, express or implied, concerning future actions, conditions or events, future operating results or the ability to generate sales, income or cash flow or to make distributions are forward-looking statements. Forward-looking statements are not guarantees of performance. They involve risks, uncertainties and assumptions. Future actions, conditions or events and future results of operations may differ materially from those expressed in these forward-looking statements. Many of the factors that will determine these results are beyond our ability to control or predict. Specific factors which could cause actual results to differ from those in the forward-looking statements include:

- price trends and overall demand for natural gas liquids, refined petroleum products, oil, carbon dioxide, natural gas, coal and other bulk materials and chemicals in North America;
- economic activity, weather, alternative energy sources, conservation and technological advances that may affect price trends and demand;
- changes in our tariff rates implemented by the Federal Energy Regulatory Commission or the California Public Utilities Commission;
- our ability to acquire new businesses and assets and integrate those operations into our existing operations, as well as our ability to make expansions to our facilities;

- difficulties or delays experienced by railroads, barges, trucks, ships or pipelines in delivering products to or from our terminals or pipelines;
- our ability to successfully identify and close acquisitions and make cost-saving changes in operations;
- shut-downs or cutbacks at major refineries, petrochemical or chemical plants, ports, utilities, military bases or other businesses that use our services or provide services or products to us;
- crude oil and natural gas production from exploration and production areas that we serve, including, among others, the Permian Basin area of West Texas;
- changes in laws or regulations, third-party relations and approvals, decisions of courts, regulators and governmental bodies that may adversely affect our business or our ability to compete;
- changes in accounting pronouncements that impact the measurement of our results of operations, the timing of when such measurements are to be made and recorded, and the disclosures surrounding these activities;
- our ability to offer and sell equity securities and debt securities or obtain debt financing in sufficient amounts to implement that portion of our business plan that contemplates growth through acquisitions of operating businesses and assets and expansions of our facilities;
- our indebtedness could make us vulnerable to general adverse economic and industry conditions, limit our ability to borrow additional funds, and/or place us at competitive disadvantages compared to our competitors that have less debt or have other adverse consequences;
- interruptions of electric power supply to our facilities due to natural disasters, power shortages, strikes, riots, terrorism, war or other causes;
- our ability to obtain insurance coverage without significant levels of self-retention of risk;
- acts of nature, sabotage, terrorism or other similar acts causing damage greater than our insurance coverage limits;
- capital markets conditions;
- the political and economic stability of the oil producing nations of the world;
- national, international, regional and local economic, competitive and regulatory conditions and developments;
- the ability to achieve cost savings and revenue growth;
- inflation;
- interest rates;
- the pace of deregulation of retail natural gas and electricity;
- foreign exchange fluctuations;
- the timing and extent of changes in commodity prices for oil, natural gas, electricity and certain agricultural products;
- the extent of our success in discovering, developing and producing oil and gas reserves, including the risks inherent in exploration and development drilling, well completion and other development activities;

- engineering and mechanical or technological difficulties with operational equipment, in well completions and workovers, and in drilling new wells;
- the uncertainty inherent in estimating future oil and natural gas production or reserves;
- the ability to complete expansion projects on time and on budget;
- the timing and success of business development efforts; and
- unfavorable results of litigation and the fruition of contingencies referred to in Note 16 to our consolidated financial statements included elsewhere in this report.

There is no assurance that any of the actions, events or results of the forward-looking statements will occur, or if any of them do, what impact they will have on our results of operations or financial condition. Because of these uncertainties, you should not put undue reliance on any forward-looking statements.

See Item 1A "Risk Factors" for a more detailed description of these and other factors that may affect the forward-looking statements. When considering forward-looking statements, one should keep in mind the risk factors described in "Risk Factors" above. The risk factors could cause our actual results to differ materially from those contained in any forward-looking statement. We disclaim any obligation, other than as required by applicable law, to update the above list or to announce publicly the result of any revisions to any of the forward-looking statements to reflect future events or developments.

Item 7A. ***Quantitative and Qualitative Disclosures About Market Risk.***

Generally, our market risk sensitive instruments and positions have been determined to be "other than trading." Our exposure to market risk as discussed below includes forward-looking statements and represents an estimate of possible changes in fair value or future earnings that would occur assuming hypothetical future movements in interest rates or commodity prices. Our views on market risk are not necessarily indicative of actual results that may occur and do not represent the maximum possible gains and losses that may occur, since actual gains and losses will differ from those estimated based on actual fluctuations in commodity prices or interest rates and the timing of transactions.

Energy Commodity Market Risk

We are exposed to commodity market risk and other external risks, such as weather-related risk, in the ordinary course of business. However, we take steps to hedge, or limit our exposure to, these risks in order to maintain a more stable and predictable earnings stream. Stated another way, we execute a hedging strategy that seeks to protect our financial position against adverse price movements and serves to minimize potential losses. Our strategy involves the use of certain energy commodity derivative contracts to reduce and minimize the risks associated with unfavorable changes in the market price of natural gas, natural gas liquids and crude oil. The derivative contracts we use include energy products traded on the New York Mercantile Exchange and over-the-counter markets, including, but not limited to, futures and options contracts, fixed price swaps and basis swaps.

Fundamentally, our hedging strategy involves taking a simultaneous position in the futures market that is equal and opposite to our position in the cash market (or physical product) in order to minimize the risk of financial loss from an adverse price change. For example, as sellers of crude oil and natural gas, we often enter into fixed price swaps and/or futures contracts to guarantee or lock-in the sale price of our oil or the margin from the sale and purchase of our natural gas at the time of market delivery, thereby directly offsetting any change in prices, either positive or negative. A hedge is successful when gains or losses in the cash market are neutralized by losses or gains in the futures transaction.

Our risk management policies prohibit us from engaging in speculative trading and we are not a party to leveraged derivatives. Furthermore, our policies require that we only enter into derivative contracts with carefully selected major financial institutions or similar counterparties based upon their credit ratings and other factors, and we maintain strict dollar and term limits that correspond to our counterparties' credit ratings. While we enter into derivative transactions only with investment grade counterparties and actively monitor their credit ratings, it is nevertheless possible that losses will result from counterparty credit risk in the future. The credit ratings of the primary parties from whom we purchase energy commodity derivative contracts are as follows (credit ratings per Standard & Poor's Rating Services):

	Credit Rating
BNP Paribas	AA+
J. Aron & Company / Goldman Sachs	AA–
Morgan Stanley	AA–

We account for our energy commodity risk management derivative contracts according to the provisions of Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" (after amendment by SFAS No. 137, SFAS No. 138, and SFAS No. 149). According to the provisions of SFAS No. 133, derivatives are measured at fair value and recognized on the balance sheet as either assets or liabilities, and in general, gains and losses on derivatives are reported on the income statement.

However, as discussed above, our principal use of energy commodity derivative contracts is to mitigate the market price risk associated with anticipated transactions for the purchase and sale of natural gas, natural gas liquids and crude oil. Using derivative contracts for this purpose helps provide us increased certainty with regard to our operating cash flows and helps us undertake further capital improvement projects, attain budget results and meet distribution targets to our partners. SFAS No. 133 categorizes such use of energy commodity derivative contracts as cash flow hedges, because the derivative contract is used to hedge the anticipated future cash flow of a transaction that is expected to occur but whose value is uncertain. Cash flow hedges are defined as hedges made with the intention of decreasing the variability in cash flows related to future transactions, as opposed to the value of an asset, liability or firm commitment, and SFAS No. 133 prescribes special hedge accounting treatment for such derivatives.

In accounting for cash flow hedges, gains and losses on the derivative contracts are reported in other comprehensive income, outside "Net Income" reported in our consolidated statements of income, but only to the extent that the gains and losses from the change in value of the derivative contracts can later offset the loss or gain from the change in value of the hedged future cash flows during the period in which the hedged cash flows affect net income. That is, for cash flow hedges, all effective components of the derivative contracts' gains and losses are recorded in other comprehensive income, pending occurrence of the expected transaction. Other comprehensive income consists of those financial items that are included in "Accumulated other comprehensive loss" in our accompanying consolidated balance sheets but not included in our net income. Thus, in highly effective cash flow hedges, where there is no ineffectiveness, other comprehensive income changes by exactly as much as the derivative contracts and there is no impact on earnings.

All remaining gains and losses on the derivative contracts (the ineffective portion) are included in current net income. The ineffective portion of the gain or loss on the derivative contracts is the difference between the gain or loss from the change in value of the derivative contract and the effective portion of that gain or loss. In addition, when the hedged forecasted transaction does take place and affects earnings, the effective part of the hedge is also recognized in the income statement, and the earlier recognized effective amounts are removed from "Accumulated other comprehensive loss." If the forecasted transaction results in an asset or liability, amounts in "Accumulated other comprehensive loss" should be reclassified into earnings when the asset or liability affects earnings through cost of sales, depreciation, interest expense, etc.

Under current accounting rules, the accumulated components of other comprehensive income are to be reported separately as accumulated other comprehensive income or loss in the stockholders' equity section of the balance sheet. For us, the gains and losses that are included in "Accumulated other comprehensive loss" in our accompanying consolidated balance sheets are primarily related to the derivative contracts associated with our hedging of anticipated future cash flows from the sales and purchases of natural gas, natural gas liquids and crude oil and represent the effective portion of the gain or loss on these derivative contacts. Accordingly, the total "Accumulated other comprehensive loss" included within the Partners' Capital section of our accompanying balance sheets as of December 31, 2007 and December 31, 2006, included amounts associated with the commodity price risk management activities of $1,377.2 million and $838.7 million, respectively.

In future periods, as the hedged cash flows from our actual purchases and sales of energy commodities affect our net income, the related gains and losses included in our accumulated other comprehensive loss as a result of our hedging are transferred to the income statement as well, effectively offsetting the changes in cash flows stemming from the hedged risk.

We measure the risk of price changes in the natural gas, natural gas liquids and crude oil markets utilizing a value-at-risk model. Value-at-risk is a statistical measure of how much the mark-to-market value of a portfolio could change during a period of time, within a certain level of statistical confidence. We utilize a closed form model to evaluate risk on a daily basis. The value-at-risk computations utilize a confidence level of 97.7% for the resultant price movement and a holding period of one day is chosen for the calculation. The confidence level used means that there is a 97.7% probability that the mark-to-market losses for a single day will not exceed the value-at-risk number presented. Derivative contracts evaluated by the model include commodity futures and options contracts, fixed price swaps, basis swaps and over-the-counter options.

For each of the years ended December 31, 2007 and 2006, our value-at-risk reached a high of $1.6 million and $2.6 million, respectively, and a low of $0.7 million and $0.5 million, respectively. Value-at-risk as of December 31, 2007, was $1.6 million and averaged $1.2 million for 2007. Value-at-risk as of December 31, 2006, was $0.6 million and averaged $1.1 million for 2006.

Our calculated value-at-risk exposure represents an estimate of the reasonably possible net losses that would be recognized on our portfolio of derivative contracts assuming hypothetical movements in future market rates, and is not necessarily indicative of actual results that may occur. It does not represent the maximum possible loss or any expected loss that may occur, since actual future gains and losses will differ from those estimated. Actual gains and losses may differ from estimates due to actual fluctuations in market rates, operating exposures and the timing thereof, as well as changes in our portfolio of derivatives during the year. In addition, as discussed above, we enter into these derivative contracts solely for the purpose of mitigating the risks that accompany certain of our business activities and, therefore, the change in the market value of our portfolio of derivative contracts, with the exception of a minor amount of hedging inefficiency, is offset by changes in the value of the underlying physical transactions. For more information on our risk management activities, see Note 14 to our consolidated financial statements included elsewhere in this report.

Interest Rate Risk

In order to maintain a cost effective capital structure, it is our policy to borrow funds using a mix of fixed rate debt and variable rate debt. The market risk inherent in our debt instruments and positions is the potential change arising from increases or decreases in interest rates as discussed below.

For fixed rate debt, changes in interest rates generally affect the fair value of the debt instrument, but not our earnings or cash flows. Conversely, for variable rate debt, changes in interest rates generally do not impact the fair value of the debt instrument, but may affect our future earnings and cash flows. We do not have an obligation to prepay fixed rate debt prior to maturity and, as a result, interest rate risk and changes in fair value should not have a significant impact on our fixed rate debt until we would be required to refinance such debt.

As of December 31, 2007 and 2006, the carrying values of our fixed rate debt were approximately $6,382.9 million and $4,551.2 million, respectively. These amounts compare to, as of December 31, 2007 and 2006, fair values of $6,518.7 million and $4,672.7 million, respectively. Fair values were determined using quoted market prices, where applicable, or future cash flow discounted at market rates for similar types of borrowing arrangements. A hypothetical 10% change (approximately 64 basis points) in the average interest rates applicable to such debt for 2007 and 2006, would result in changes of approximately $259.9 million and $183.4 million, respectively, in the fair values of these instruments.

The carrying value and fair value of our variable rate debt, including associated accrued interest and excluding the value of interest rate swap agreements (discussed below), was $684.5 million as of December 31, 2007 and $1,195.6 million as of December 31, 2006. A hypothetical 10% change in the weighted average interest rate on all of our borrowings, when applied to our outstanding balance of variable rate debt as of December 31, 2007 and 2006, including adjustments for notional swap amounts, would result in changes of approximately $19.1 million and $20.3 million, respectively, in our 2007 and 2006 annual pre-tax earnings.

As of December 31, 2007 and 2006, we were a party to interest rate swap agreements with notional principal amounts of $2.3 billion and $2.1 billion, respectively. An interest rate swap agreement is a contractual agreement entered into between two counterparties under which each agrees to make periodic interest payments to the other for an agreed period of time based upon a predetermined amount of principal, which is called the notional principal amount. Normally at each payment or settlement date, the party who owes more pays the net amount; so at any given settlement date only one party actually makes a payment. The principal amount is notional because there is no need to exchange actual amounts of principal.

We entered into our interest rate swap agreements for the purposes of (i) hedging the interest rate risk associated with our fixed rate debt obligations and (ii) transforming a portion of the underlying cash flows related to our long-term fixed rate debt securities into variable rate debt in order to achieve our desired mix of fixed and variable rate debt. Since the fair value of our fixed rate debt varies with changes in the market rate of interest, we enter into swap agreements to receive a fixed and pay a variable rate of interest. Such swap agreements result in future cash flows that vary with the market rate of interest, and therefore hedge against changes in the fair value of our fixed rate debt due to market rate changes.

As of both December 31, 2007 and 2006, all of our interest rate swap agreements represented fixed-for-variable rate swaps, where we agreed to pay our counterparties a variable rate of interest on a notional principal amount, comprised of principal amounts from various series of our long-term fixed rate senior notes. In exchange, our counterparties agreed to pay us a fixed rate of interest, thereby allowing us to transform our fixed rate liabilities into variable rate obligations without the incurrence of additional loan origination or conversion costs.

We monitor our mix of fixed rate and variable rate debt obligations in light of changing market conditions and from time to time may alter that mix by, for example, refinancing balances outstanding under our variable rate debt with fixed rate debt (or vice versa) or by entering into interest rate swap agreements or other interest rate hedging agreements. In general, we attempt to maintain an overall target mix of approximately 50% fixed rate debt and 50% variable rate debt.

As of December 31, 2007, our cash and investment portfolio did not include fixed-income securities. Due to the short-term nature of our investment portfolio, a hypothetical 10% increase in interest rates would not have a material effect on the fair market value of our portfolio. Since we have the ability to liquidate this portfolio, we do not expect our operating results or cash flows to be materially affected to any significant degree by the effect of a sudden change in market interest rates on our investment portfolio.

See Note 9 to our consolidated financial statements included elsewhere in this report for additional information related to our debt instruments; for more information on our interest rate swap agreements, see Note 14.

Item 8. ***Financial Statements and Supplementary Data.***

The information required in this Item 8 is included in this report as set forth in the "Index to Financial Statements" on page 114.

Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.***

None.

Item 9A. ***Controls and Procedures.***

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

As of December 31, 2007, our management, including our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15(b) under the Securities Exchange Act of 1934. There are inherent limitations to the effectiveness of any system of disclosure controls and procedures, including the possibility of human error and the circumvention or overriding of the controls and procedures. Accordingly, even effective disclosure controls and procedures can only provide reasonable assurance of achieving their control objectives. Based upon and as of the date of the evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that the design and operation of our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed in the reports we file and submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported as and when required, and is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation under the framework in *Internal Control – Integrated Framework*, our management concluded that our internal control over financial reporting was effective as of December 31, 2007.

The effectiveness of our internal control over financial reporting as of December 31, 2007, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

Certain businesses we acquired during 2007 were excluded from the scope of our management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2007. The excluded businesses consisted of the following:

- the Vancouver Wharves bulk marine terminal, acquired May 30, 2007; and
- the terminal assets and operations acquired from Marine Terminals, Inc., effective September 1, 2007.

These businesses, in the aggregate, constituted 0.6% of our total operating revenues for 2007 and 1.2% of our total assets as of December 31, 2007.

Changes in Internal Control Over Financial Reporting

There has been no change in our internal control over financial reporting during the fourth quarter of 2007 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. ***Other Information.***

None.

PART III

Item 10. *Directors, Executive Officers and Corporate Governance*

Directors and Executive Officers of our General Partner and its Delegate

Set forth below is certain information concerning the directors and executive officers of our general partner and KMR, the delegate of our general partner. All directors of our general partner are elected annually by, and may be removed by, Kinder Morgan (Delaware), Inc. as its sole shareholder, and all directors of KMR are elected annually by, and may be removed by, our general partner as the sole holder of KMR's voting shares. Kinder Morgan (Delaware), Inc. is a wholly owned subsidiary of Knight. All officers of our general partner and all officers of KMR serve at the discretion of the board of directors of our general partner.

Name	Age	Position with our General Partner and KMR
Richard D. Kinder	63	Director, Chairman and Chief Executive Officer
C. Park Shaper	39	Director and President
Steven J. Kean	46	Executive Vice President and Chief Operating Officer
Edward O. Gaylord	76	Director
Gary L. Hultquist	64	Director
Perry M. Waughtal	72	Director
Kimberly A. Dang	38	Vice President, Investor Relations and Chief Financial Officer
Jeffrey R. Armstrong	39	Vice President (President, Terminals)
Thomas A. Bannigan	54	Vice President (President, Products Pipelines)
Richard T. Bradley	52	Vice President (President, CO_2)
David D. Kinder	33	Vice President, Corporate Development and Treasurer
Joseph Listengart	39	Vice President, General Counsel and Secretary
Scott E. Parker	47	Vice President (President, Natural Gas Pipelines)
James E. Street	51	Vice President, Human Resources and Administration

Richard D. Kinder is Director, Chairman and Chief Executive Officer of KMR, Kinder Morgan G.P., Inc. and Knight. Mr. Kinder has served as Director, Chairman and Chief Executive Officer of KMR since its formation in February 2001. He was elected Director, Chairman and Chief Executive Officer of Knight in October 1999. He was elected Director, Chairman and Chief Executive Officer of Kinder Morgan G.P., Inc. in February 1997. Mr. Kinder was elected President of KMR, Kinder Morgan G.P., Inc. and Knight in July 2004 and served as President until May 2005. He has also served as Chief Manager, and as a member of the Board of Managers of Knight Holdco LLC since May 2007. Mr. Kinder is the uncle of David Kinder, Vice President, Corporate Development and Treasurer of KMR, Kinder Morgan G.P., Inc. and Knight.

C. Park Shaper is Director and President of KMR, Kinder Morgan G.P., Inc. and Knight. Mr. Shaper was elected President of KMR, Kinder Morgan G.P., Inc. and Knight in May 2005. He served as Executive Vice President of KMR, Kinder Morgan G.P., Inc. and Knight from July 2004 until May 2005. Mr. Shaper was elected Director of KMR and Kinder Morgan G.P., Inc. in January 2003 and of Knight in May of 2007. He was elected Vice President, Treasurer and Chief Financial Officer of KMR upon its formation in February 2001, and served as its Treasurer until January 2004, and its Chief Financial Officer until May 2005. He was elected Vice President, Treasurer and Chief Financial Officer of Knight in January 2000, and served as its Treasurer until January 2004, and its Chief Financial Officer until May 2005. Mr. Shaper was elected Vice President, Treasurer and Chief Financial Officer of Kinder Morgan G.P., Inc. in January 2000, and served as its Treasurer until January 2004 and its Chief Financial Officer until May 2005. He has also served as President, and as a member of the Board of Managers, of Knight Holdco LLC since May 2007. He received a Masters of Business Administration degree from the J.L. Kellogg Graduate School of Management at Northwestern University. Mr. Shaper also has a Bachelor of Science degree in Industrial Engineering and a Bachelor of Arts degree in Quantitative Economics from Stanford University. Mr. Shaper is also a trust manager of Weingarten Realty Investors.

Steven J. Kean is Executive Vice President and Chief Operating Officer of KMR, Kinder Morgan G.P., Inc. and Knight. Mr. Kean was elected Executive Vice President and Chief Operating Officer of KMR, Kinder Morgan G.P., Inc. and Knight in January 2006. He served as Executive Vice President, Operations of KMR, Kinder Morgan G.P., Inc. and Knight from May 2005 to January 2006. He served as President, Texas Intrastate Pipeline Group from June

2002 until May 2005. He served as Vice President of Strategic Planning for the Kinder Morgan Gas Pipeline Group from January 2002 until June 2002. He has also served as Chief Operating Officer, and as a member of the Board of Managers, of Knight Holdco LLC since May 2007. Mr. Kean received his Juris Doctor from the University of Iowa in May 1985 and received a Bachelor of Arts degree from Iowa State University in May 1982.

Edward O. Gaylord is a Director of KMR and Kinder Morgan G.P., Inc. Mr. Gaylord was elected Director of KMR upon its formation in February 2001. Mr. Gaylord was elected Director of Kinder Morgan G.P., Inc. in February 1997. Since 1989, Mr. Gaylord has been the Chairman of the board of directors of Jacintoport Terminal Company, a liquid bulk storage terminal on the Houston, Texas ship channel.

Gary L. Hultquist is a Director of KMR and Kinder Morgan G.P., Inc. Mr. Hultquist was elected Director of KMR upon its formation in February 2001. He was elected Director of Kinder Morgan G.P., Inc. in October 1999. Since 1995, Mr. Hultquist has been the Managing Director of Hultquist Capital, LLC, a San Francisco-based strategic and merger advisory firm.

Perry M. Waughtal is a Director of KMR and Kinder Morgan G.P., Inc. Mr. Waughtal was elected Director of KMR upon its formation in February 2001. Mr. Waughtal was elected Director of Kinder Morgan G.P., Inc. in April 2000. Since 1994, Mr. Waughtal has been the Chairman of Songy Partners Limited, an Atlanta, Georgia based real estate investment company. Mr. Waughtal is also a director of HealthTronics, Inc.

Kimberly A. Dang is Vice President, Investor Relations and Chief Financial Officer of KMR, Kinder Morgan G.P., Inc. and Knight. Mrs. Dang was elected Chief Financial Officer of KMR, Kinder Morgan G.P., Inc. and Knight in May 2005. She served as Treasurer of KMR, Kinder Morgan G.P., Inc. and Knight from January 2004 to May 2005. She was elected Vice President, Investor Relations of KMR, Kinder Morgan G.P., Inc. and Knight in July 2002. From November 2001 to July 2002, she served as Director, Investor Relations of KMR, Kinder Morgan G.P., and Knight. From May 2001 until November 2001, Mrs. Dang was an independent financial consultant. From September 2000 until May 2001, she served as an associate and later a principal at Murphree Venture Partners, a venture capital firm. She has also served as Chief Financial Officer of Knight Holdco LLC since May 2007. Mrs. Dang has received a Masters in Business Administration degree from the J.L. Kellogg Graduate School of Management at Northwestern University and a Bachelor of Business Administration degree in accounting from Texas A&M University.

Jeffrey R. Armstrong is Vice President (President, Terminals) of KMR and Kinder Morgan G.P., Inc. Mr. Armstrong became Vice President (President, Terminals) in July 2003. He served as President, Kinder Morgan Liquids Terminals LLC from March 1, 2001, when the company was formed via the acquisition of GATX Terminals, through July 2003. From 1994 to 2001, Mr. Armstrong worked for GATX Terminals, where he was General Manager of their East Coast operations. He received his Bachelor’s degree from the United States Merchant Marine Academy and an MBA from the University of Notre Dame.

Thomas A. Bannigan is Vice President (President, Products Pipelines) of KMR and Kinder Morgan G.P., Inc. and President and Chief Executive Officer of Plantation Pipe Line Company. Mr. Bannigan was elected Vice President (President, Products Pipelines) of KMR upon its formation in February 2001. He was elected Vice President (President, Products Pipelines) of Kinder Morgan G.P., Inc. in October 1999. Mr. Bannigan has served as President and Chief Executive Officer of Plantation Pipe Line Company since May 1998. Mr. Bannigan received his Juris Doctor, cum laude, from Loyola University in 1980 and received a Bachelors degree from the State University of New York in Buffalo.

Richard T. Bradley is Vice President (President, CO_2) of KMR and of Kinder Morgan G.P., Inc. and President of Kinder Morgan CO_2 Company, L.P. Mr. Bradley was elected Vice President (President, CO_2) of KMR upon its formation in February 2001 and Vice President (President, CO_2) of Kinder Morgan G.P., Inc. in April 2000. Mr. Bradley has been President of Kinder Morgan CO_2 Company, L.P. (formerly known as Shell CO_2 Company, Ltd.) since March 1998. Mr. Bradley received a Bachelor of Science in Petroleum Engineering from the University of Missouri at Rolla.

David D. Kinder is Vice President, Corporate Development and Treasurer of KMR, Kinder Morgan G.P., Inc. and Knight. Mr. Kinder was elected Treasurer of KMR, Kinder Morgan G.P., Inc. and Knight in May 2005. He was elected Vice President, Corporate Development of KMR, Kinder Morgan G.P., Inc. and Knight in October 2002. He served as manager of corporate development for Knight and Kinder Morgan G.P., Inc. from January 2000 to October 2002. He has also served as Treasurer of Knight Holdco LLC since May 2007. Mr. Kinder graduated cum laude with a Bachelors degree in Finance from Texas Christian University in 1996. Mr. Kinder is the nephew of Richard D. Kinder.

Joseph Listengart is Vice President, General Counsel and Secretary of KMR, Kinder Morgan G.P., Inc. and Knight. Mr. Listengart was elected Vice President, General Counsel and Secretary of KMR upon its formation in February 2001. He was elected Vice President and General Counsel of Kinder Morgan G.P., Inc. and Vice President, General Counsel and Secretary of Knight in October 1999. Mr. Listengart was elected Secretary of Kinder Morgan G.P., Inc. in November 1998 and has been an employee of Kinder Morgan G.P., Inc. since March 1998. He has also served as General Counsel and Secretary of Knight Holdco LLC since May 2007. Mr. Listengart received his Masters in Business Administration from Boston University in January 1995, his Juris Doctor, magna cum laude, from Boston University in May 1994, and his Bachelor of Arts degree in Economics from Stanford University in June 1990.

Scott E. Parker is Vice President (President, Natural Gas Pipelines) of KMR, Kinder Morgan G.P., Inc. and Knight. He was elected Vice President (President, Natural Gas Pipelines) of KMR, Kinder Morgan G.P., Inc. and Knight in May 2005. Mr. Parker served as President of NGPL from March 2003 to May 2005. Mr. Parker served as Vice President, Business Development of NGPL from January 2001 to March 2003. He held various positions at NGPL from January 1984 to January 2001. Mr. Parker holds a Bachelor’s degree in accounting from Governors State University.

James E. Street is Vice President, Human Resources and Administration of KMR, Kinder Morgan G.P., Inc. and Knight. Mr. Street was elected Vice President, Human Resources and Administration of KMR upon its formation in February 2001. He was elected Vice President, Human Resources and Administration of Kinder Morgan G.P., Inc. and Knight in August 1999. Mr. Street received a Masters of Business Administration degree from the University of Nebraska at Omaha and a Bachelor of Science degree from the University of Nebraska at Kearney.

Corporate Governance

We have a separately designated standing audit committee established in accordance with Section 3(a)(58)(A) of the Securities Exchange Act of 1934 comprised of Messrs. Gaylord, Hultquist and Waughtal. Mr. Gaylord is the chairman of the audit committee and has been determined by the board to be an "audit committee financial expert." The board has determined that all of the members of the audit committee are independent as described under the relevant standards.

We have not, nor has our general partner nor KMR, made, within the preceding three years, contributions to any tax-exempt organization in which any of our or KMR’s independent directors serves as an executive officer that in any single fiscal year exceeded the greater of $1.0 million or 2% of such tax-exempt organization’s consolidated gross revenues.

On April 11, 2007, our chief executive officer certified to the New York Stock Exchange, as required by Section 303A.12(a) of the New York Stock Exchange Listed Company Manual, that as of April 11, 2007, he was not aware of any violation by us of the New York Stock Exchange’s Corporate Governance listing standards. We have also filed as an exhibit to this report the Sarbanes-Oxley Act Section 302 certifications regarding the quality of our public disclosure.

We make available free of charge within the "Investors" information section of our Internet website, at www.kindermorgan.com, and in print to any unitholder who requests, the governance guidelines, the charters of the audit committee, compensation committee and nominating and governance committee, and our code of business conduct and ethics (which applies to senior financial and accounting officers and the chief executive officer, among others). Requests for copies may be directed to Investor Relations, Kinder Morgan Energy Partners, L.P., 500 Dallas Street, Suite 1000, Houston, Texas 77002, or telephone (713) 369-9490. We intend to disclose any amendments to our code of business conduct and ethics that would otherwise be disclosed on Form 8-K and any waiver from a provision of that code granted to our executive officers or directors that would otherwise be disclosed on Form 8-K on our Internet website within four business days following such amendment or waiver. The information contained on or connected to our Internet website is not incorporated by reference into this Form 10-K and should not be considered part of this or any other report that we file with or furnish to the SEC.

Interested parties may contact our lead director, the chairpersons of any of the board’s committees, the independent directors as a group or the full board by mail to Kinder Morgan Management, LLC, 500 Dallas Street, Suite 1000, Houston, Texas 77002, Attention: General Counsel, or by e-mail within the "Contact Us" section of our Internet website, at www.kindermorgan.com. Any communication should specify the intended recipient.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16 of the Securities Exchange Act of 1934 requires our directors and officers, and persons who own more than 10% of a registered class of our equity securities, to file initial reports of ownership and reports of changes in ownership with the Securities and Exchange Commission. Such persons are required by SEC regulation to furnish us with copies of all Section 16(a) forms they file.

Based solely on our review of the copies of such forms furnished to us and written representations from our executive officers and directors, we believe that all Section 16(a) filing requirements were met during 2007.

Item 11. ***Executive Compensation.***

As is commonly the case for publicly traded limited partnerships, we have no officers. Under our limited partnership agreement, Kinder Morgan G.P., Inc., as our general partner, is to direct, control and manage all of our activities. Pursuant to a delegation of control agreement, Kinder Morgan G.P., Inc. has delegated to KMR the management and control of our business and affairs to the maximum extent permitted by our partnership agreement and Delaware law, subject to our general partner's right to approve certain actions by KMR. The executive officers and directors of Kinder Morgan G.P., Inc. serve in the same capacities for KMR. Certain of those executive officers also serve as executive officers of Knight, formerly KMI, and of Knight Holdco LLC, Knight's privately owned parent company. Except as indicated otherwise, all information in this report with respect to compensation of executive officers describes the total compensation received by those persons in all capacities for services rendered to us, our subsidiaries and our affiliates, including Knight and Knight Holdco LLC. In this Item 11, "we," "our" or "us" refers to Kinder Morgan Energy Partners, L.P. and, where appropriate, Kinder Morgan G.P., Inc., KMR and Knight.

Compensation Discussion and Analysis

Program Objectives

We are a publicly traded master limited partnership, and our businesses consist of a diversified portfolio of energy transportation, storage and production assets. We seek to attract and retain executives who will help us achieve our primary business strategy objective of growing the value of our portfolio of businesses for the benefit of our unitholders. To help accomplish this goal, we have designed an executive compensation program that rewards individuals with competitive compensation that consists of a mix of cash, benefit plans and long-term compensation, with a majority of executive compensation tied to the "at risk" portions of the annual cash bonus.

The key objectives of our executive compensation program are to attract, motivate and retain executives who will advance our overall business strategies and objectives to create and return value to our unitholders. We believe that an effective executive compensation program should link total compensation to financial performance and to the attainment of short- and long-term strategic, operational, and financial objectives. We also believe it should provide competitive total compensation opportunities at a reasonable cost. In designing our executive compensation program, we have recognized that our executives have a much greater portion of their overall compensation at-risk than do our other employees; consequently, we have tried to establish the at-risk portions of our executive total compensation at levels that recognize their much increased level of responsibility and their ability to influence business results.

Currently, our executive compensation program is principally comprised of the following two elements: (i) base cash salary; and (ii) possible annual cash bonus (reflected in the Summary Compensation Table below as Non-Equity Incentive Plan Compensation). It has been our philosophy to pay our executive officers a base salary not to exceed $200,000, which we believe is below annual base salaries for comparable positions in the marketplace. At its January 2008 meeting, KMR's compensation committee (discussed more fully below) agreed to raise the cap for our executive officers' base salaries to an annual amount not to exceed $300,000. No increases above $200,000 have been implemented at this time. If this increase was implemented, we believe the base salaries paid to our executive officers would continue to be below the industry average for similarly positioned executives. While not awarded by us, KMR' compensation committee was aware of the units awarded by Knight Holdco LLC (as discussed more fully below) and took these awards into account as components of the total compensation received by our executive officers.

In addition, we believe that the compensation of our Chief Executive Officer, Chief Financial Officer and the executives named below, collectively referred to in this Item 11 as our named executive officers, should be directly and materially tied to the financial performance of Knight and us, and should be aligned with the interests of our unitholders. Therefore, the majority of our named executive officers' compensation is allocated to the "at risk" portion of our compensation program—the annual cash bonus. Accordingly, for 2007, our executive compensation was weighted toward the cash bonus, payable on the basis of achieving (i) an earnings before interest, taxes, depreciation, depletion and amortization (referred to as EBITDA) less capital spending target by Knight; and (ii) a cash distribution per common unit target by us.

We periodically compare our executive compensation components with market information. The purpose of this comparison is to ensure that our total compensation package operates effectively, remains both reasonable and competitive with the energy industry, and is generally comparable to the compensation offered by companies of similar size and scope as us. We also keep abreast of current trends, developments, and emerging issues in executive compensation, and if appropriate, will obtain advice and assistance from outside legal, compensation or other advisors.

We have endeavored to design our executive compensation program and practices with appropriate consideration of all tax, accounting, legal and regulatory requirements. Section 162(m) of the Internal Revenue Code limits the deductibility of certain compensation for our executive officers to $1,000,000 of compensation per year; however, if specified conditions are met, certain compensation may be excluded from consideration of the $1,000,000 limit. Since the bonuses paid to our executive officers are paid under Knight's Annual Incentive Plan as a result of reaching designated financial targets established by KMR's and Knight's compensation committees, we expect that all compensation paid to our executives would qualify for deductibility under federal income tax rules. Though we are advised that we and private companies, such as Knight, are not subject to section 162(m), we and Knight have chosen to generally operate as if this code section does apply to us and Knight as a measure of appropriate governance.

Prior to 2006, long-term equity awards comprised a third element of our executive compensation program. These awards primarily consisted of grants of restricted KMI stock and grants of non-qualified options to acquire shares of KMI common stock, both pursuant to the provisions of KMI's Amended and Restated 1999 Stock Plan, referred to in this report as the KMI stock plan. Prior to 2003, we used both KMI stock options and restricted KMI stock as the principal components of long-term executive compensation, and beginning in 2003, we used grants of restricted stock exclusively as the principal component of long-term executive compensation. For each of the years ended December 31, 2006 and 2007, no restricted stock or options to purchase shares of KMI, KMP or KMR were granted to any of our named executive officers.

Additionally, in connection with KMI's going-private transaction, Knight Holdco LLC awarded members of Knight's management Class A-1 and Class B units of Knight Holdco LLC. In accordance with SFAS No. 123R, Knight Holdco LLC is required to recognize compensation expense in connection with the Class A-1 and Class B units over the expected life of such units. As a subsidiary of Knight Holdco LLC, we are, under accounting rules, allocated a portion of this compensation expense, although none of us or any of our subsidiaries have any obligation, nor do we expect, to pay any amounts in respect of such units. For more information concerning the Knight Holdco LLC units, see Item 13. "Certain Relationships and Related Transactions, and Director Independence—Related Transactions—KMI Going-Private Transaction".

Behaviors Designed to Reward

Our executive compensation program is designed to reward individuals for advancing our business strategies and the interests of our stakeholders, and we prohibit engaging in any detrimental activities, such as performing services for a competitor, disclosing confidential information or violating appropriate business conduct standards. Each executive is held accountable to uphold and comply with company guidelines, which require the individual to maintain a discrimination-free workplace, to comply with orders of regulatory bodies, and to maintain high standards of operating safety and environmental protection.

Unlike many companies, we have no executive perquisites and, with respect to our United States-based executives, we have no supplemental executive retirement, non-qualified supplemental defined benefit/contribution, deferred compensation or split dollar life insurance programs. Additionally, we do not have employment agreements (other than with our Chairman and Chief Executive Officer, Richard D. Kinder), special severance agreements or change of control agreements for our U.S. executives. Our executives are eligible for the same severance policy as our workforce, which caps severance payments to an amount equal to six months of salary. We have no executive company cars or executive car allowances nor do we offer or pay for financial planning services. Additionally, we do not own any corporate aircraft and we do not pay for executives to fly first class. We believe that we are currently below competitive levels for comparable companies in this area of our overall compensation package; however, we have no current plans to change our policy of not offering such executive benefits, perquisite programs or special executive severance arrangements.

At his request, Mr. Richard D. Kinder, our Chairman and Chief Executive Officer, receives $1 of base salary per year. Additionally, Mr. Kinder has requested that he receive no annual bonus, unit grants, or other compensation from us. Mr. Kinder does not have any deferred compensation, supplemental retirement or any other special benefit, compensation or perquisite arrangement with us. Each year Mr. Kinder reimburses us for his portion of health care premiums and parking expenses. Mr. Kinder was awarded Class B units by and in Knight Holdco LLC in connection with KMI's going-private transaction, and while we are, under accounting rules, allocated compensation expense attributable to such Class B units, we have no obligation, nor do we expect, to pay any amounts in connection with the Class B units.

Elements of Compensation

As outlined above, our executive compensation program currently is principally comprised of the following two elements: (i) a base cash salary; and (ii) a possible annual cash bonus. With regard to our named executive officers other than our Chief Executive Officer, KMR's compensation committee reviews and approves annually the financial goals and objectives of both Knight and us that are relevant to the compensation of our named executive officers. Generally following the regularly scheduled fourth quarter board meeting in each year, the committee solicits information from other directors, the Chief Executive Officer and other relevant members of senior management regarding the performance of our named executive officers other than our Chief Executive Officer during that year. Our Chief Executive Officer makes compensation recommendations to the committee with respect to our named executive officers, other than himself. The committee obtains the information and the recommendations prior to the regularly scheduled first quarter board meeting.

Annually, at KMR's regularly scheduled first quarter board meeting, the committee evaluates the performance of our named executive officers other than our Chief Executive Officer and makes determinations regarding the terms of their continued employment and compensation for that year. If the committee deems it advisable, it may, rather than determine the terms of continued employment and compensation for the named executive officers (other than the Chief Executive Officer), make a recommendation with respect thereto to the independent members of the board, who make the determination at the first quarter board meeting. The committee also determines bonuses for the prior year based on the performance targets set therefor, and sets performance targets for the present year for bonus and other relevant purposes.

If any of KMR's or our general partner's executive officers is also an executive officer of Knight, the committee's compensation determination or recommendation (i) may be with respect to the aggregate compensation to be received by such officer from Knight, KMR, and our general partner that is to be allocated among them in accordance with procedures approved by the committee, if such aggregate compensation set by the committee and that set by the committee or the board of KMR are the same, or alternatively (ii) may be with respect to the compensation to be received by such executive officers from Knight, KMR or our general partner, as the case may be, in which case such compensation will not be allocated among Knight, on the one hand, and KMR, our general partner and us, on the other. Thereafter, the committee or the Chief Executive Officer will discuss the committee's evaluation and the determination as to compensation with the named executive officers.

In addition, the compensation committee has the sole authority to retain (and terminate as necessary) and compensate any compensation consultants, counsel and other firms of experts to advise it as it determines necessary or appropriate. The committee has the sole authority to approve any such firm's fees and other retention terms, and we and Knight, as applicable, will make adequate provision for the payment of all fees and other compensation, approved by the committee, to any such firm employed by the committee. The committee also has sole authority to determine if any compensation consultant is to be used to assist in the evaluation of director, Chief Executive Officer or senior executive compensation and will have sole authority to retain and terminate any such compensation consultant and to approve the consultant's fees and other retention terms.

Base Salary

Base salary is paid in cash. For each of the years 2007 and 2006, all of our named executive officers, with the exception of our Chairman and Chief Executive Officer who receives $1 of base salary per year as described above, were paid a base salary of $200,000 per year. At KMR's first quarter 2008 board meeting, the compensation committee agreed to raise the base salary cap for our executive officers, beginning in 2008, to an annual amount not to exceed $300,000. No increases above $200,000 have been implemented at this time. Generally, we believe that our executive officers' base salaries are (and will continue to be following any implementation of the previously described increase) below base salaries for executives in similar positions and with similar responsibilities at companies of comparable size and scope.

Possible Annual Cash Bonus (Non-Equity Cash Incentive)

Our possible annual cash bonuses are provided for under Knight's Annual Incentive Plan, which became effective January 18, 2005. The overall purpose of the Knight Annual Incentive Plan is to increase our executive officers' and our employees' personal stake in the continued success of Knight and us by providing them additional incentives through the possible payment of annual cash bonuses. Under the plan, annual cash bonuses may be paid to our executive officers and other employees depending on a variety of factors, including their individual performance, Knight's financial performance, the financial performance of Knight's subsidiaries (including us), safety and environmental goals and regulatory compliance.

The plan is administered by the compensation committee of Knight's board of directors. The compensation committee is authorized to grant awards under the plan, interpret the plan, adopt rules and regulations for carrying out the plan, and make all determinations necessary or advisable for the administration of the plan.

All of the employees of Knight and its subsidiaries, including KMGP Services Company, Inc., are eligible to participate in the plan, except employees who are included in a unit of employees covered by a collective bargaining agreement unless such agreement expressly provides for eligibility under the plan. However, only eligible employees who are selected by the KMR and Knight compensation committees will actually participate in the plan and receive bonuses.

The plan consists of two components: the executive plan component and the non-executive plan component. Our Chairman and Chief Executive Officer and all employees who report directly to the Chairman are eligible for the executive plan component; however, as stated elsewhere in this report, Mr. Richard D. Kinder, our Chairman and Chief Executive Officer, has elected to not participate under the plan. As of January 31, 2008, excluding Mr. Richard D. Kinder, eleven of our current executive officers were eligible to participate in the executive plan component. All other U.S. eligible employees were eligible for the non-executive plan component.

The KMR compensation committee determines which of our eligible employees will be eligible to participate under the executive plan component of the plan. At or before the start of each calendar year (or later, to the extent allowed under Internal Revenue Code regulations), performance objectives for that year are identified. The performance objectives are based on one or more of the criteria set forth in the plan. The KMR compensation committee establishes a bonus opportunity for each executive officer, which is our portion of the amount of the bonus the executive officer will earn if the performance objectives are fully satisfied. The compensation committee may specify a minimum acceptable level of achievement of each performance objective below which no bonus is payable with respect to that objective. The compensation committee may set additional levels above the minimum (which may also be above the targeted performance objective), with a formula to determine the percentage of the bonus opportunity to be earned at each level of achievement above the minimum. Performance at a level above the targeted performance objective may entitle the executive officer to earn a bonus in excess of 100% of the bonus opportunity. However, the maximum payout to any individual under the plan for any year is $2.0 million, and the KMR compensation committee has the discretion to reduce the bonus amount payable by us in any performance period.

Performance objectives may be based on one or more of the following criteria:

- Knight's EBITDA less capital spending, or the EBITDA less capital spending of one of its subsidiaries or business units;
- Knight's net income or the net income of one of its subsidiaries or business units;
- Knight's revenues or the revenues of one of its subsidiaries or business units;

- Knight's unit revenues minus unit variable costs or the unit revenues minus unit variable costs of one of its subsidiaries or business units;
- Knight's return on capital, return on equity, return on assets, or return on invested capital, or the return on capital, return on equity, return on assets, or return on invested capital of one of its subsidiaries or business units;
- Knight's cash flow return on assets or cash flows from operating activities, or the cash flow return on assets or cash flows from operating activities of one of its subsidiaries or business units;
- Knight's capital expenditures or the capital expenditures of one of its subsidiaries or business units;
- Knight's operations and maintenance expense or general and administrative expense, or the operations and maintenance expense or general and administrative expense of one of its subsidiaries or business units; or
- Knight's debt-equity ratios and key profitability ratios, or the debt-equity ratios and key profitability ratios of one of its subsidiaries or business units.

The KMR compensation committee set two performance objectives for 2007 under both the executive plan component and the non-executive plan component. The 2007 performance objectives were $3.44 in cash distributions per common unit at KMP, and $1,089.5 million of EBITDA less capital spending at Knight. These targets were the same as our and Knight's previously disclosed 2007 budget expectations. At the end of 2007, the KMR compensation committee determined and certified in writing the extent to which the performance objectives had been attained and the extent to which the bonus opportunity had been earned under the formula previously established by the KMR compensation committee. In 2007, both we and Knight exceeded our established targets.

The table below sets forth the bonus opportunities that could have been payable by us and Knight to our executive officers if the performance objectives established by the KMR compensation committee for 2007 had been 100% achieved. The KMR compensation committee may, at its sole discretion, reduce the amount of the portion of the bonus actually paid by us to any executive officer under the plan from the amount of any bonus opportunity open to such executive officer; and, because payments under the plan for our executive officers are determined by comparing actual performance to the performance objectives established by the compensation committee each year for eligible executive officers chosen to participate for that year, it is not possible to accurately predict any amounts that will actually be paid under the executive plan portion of the plan over the life of the plan. The compensation committee set bonus opportunities under the plan for 2007 for the executive officers at dollar amounts in excess of that which were expected to actually be paid under the plan. The actual payout amounts under the Non-Equity Incentive Plan Awards made in 2007 are set forth in the Summary Compensation Table in this report in the column entitled "Non-Equity Incentive Plan Compensation."

Knight Annual Incentive Plan
Bonus Opportunities for 2007

Name and Principal Position	Dollar Value	
Richard D. Kinder, Chairman and Chief Executive Officer..................	$ —	(1)
Kimberly A. Dang, Vice President and Chief Financial Officer.............	1,000,000	(2)
Steven J. Kean, Executive Vice President and Chief Operating Officer....	1,500,000	(3)
Scott E. Parker, Vice President (President, Natural Gas Pipelines)..........	1,500,000	(3)
C. Park Shaper, Director and President...	1,500,000	(3)

(1) Declined to participate.

(2) Under the plan, for 2007, if neither of the targets was met, no bonus opportunities would have been provided; if one of the targets was met, $500,000 in bonus opportunities would have been available; if both of the targets had been exceeded by 10%, $1,500,000 in bonus opportunities would have been available. The KMR compensation committee may, in its sole discretion, reduce the award payable by us to any participant for any reason.

(3) Under the plan, for 2007, if neither of the targets was met, no bonus opportunities would have been provided; if one of the targets was met, $750,000 in bonus opportunities would have been available; if both of the targets had been exceeded by 10%, $2,000,000 in bonus opportunities would have been available. The KMR compensation committee may, in its sole discretion, reduce the award payable by us to any participant for any reason.

Knight may amend the plan from time to time without shareholder approval except as required to satisfy the Internal Revenue Code or any applicable securities exchange rules. Awards may be granted under the plan for calendar years 2008 through 2009, unless the plan is terminated earlier by Knight. However, the plan will remain in effect until payment has been completed with respect to all awards granted under the plan prior to its termination.

Other Compensation

Knight Inc. Savings Plan. The Knight Inc. Savings Plan is a defined contribution 401(k) plan. The plan permits all full-time employees of Knight and KMGP Services Company, Inc., including the named executive officers, to contribute between 1% and 50% of base compensation, on a pre-tax basis, into participant accounts. In addition to a mandatory contribution equal to 4% of base compensation per year for most plan participants, our general partner may make special discretionary contributions. Certain employees' contributions are based on collective bargaining agreements. The mandatory contributions are made each pay period on behalf of each eligible employee. Participants may direct the investment of both their contributions and employer contributions into a variety of investments at the employee's discretion. Plan assets are held and distributed pursuant to a trust agreement.

Employer contributions for employees vest on the second anniversary of the date of hire. Effective October 1, 2005, for new employees of our Terminals business segment, a tiered employer contribution schedule was implemented. This tiered schedule provides for employer contributions of 1% for service less than one year, 2% for service between one and two years, 3% for service between two and five years, and 4% for service of five years or more. All employer contributions for employees of our Terminals business segment hired after October 1, 2005 vest on the fifth anniversary of the date of hire (effective January 1, 2008, this five year anniversary date for Terminals employees was changed to three years to comply with changes in federal regulations).

At its July 2007 meeting, the compensation committee of the KMR and Knight boards of directors approved a special contribution of an additional 1% of base pay into the Savings Plan for each eligible employee. Each eligible employee will receive an additional 1% company contribution based on eligible base pay each pay period beginning with the first pay period of August 2007 and continuing through the last pay period of July 2008. The additional 1% contribution does not change or otherwise impact, the annual 4% contribution that eligible employees currently receive. It may be converted to any other Savings Plan investment fund at any time and it will vest according to the same vesting schedule described in the preceding paragraph. Since this additional 1% company contribution is discretionary, KMR and Knight compensation committee approvals will be required annually for each additional contribution. During the first quarter of 2008, excluding our portion of the 1% additional contribution described above, we will not make any additional discretionary contributions to individual accounts for 2007.

Additionally, in 2006, an option to make after-tax "Roth" contributions (Roth 401(k) option) to a separate participant account was added to the Savings Plan as an additional benefit to all participants. Unlike traditional 401(k) plans, where participant contributions are made with pre-tax dollars, earnings grow tax-deferred, and the withdrawals are treated as taxable income, Roth 401(k) contributions are made with after-tax dollars, earnings are tax-free, and the withdrawals are tax-free if they occur after both (i) the fifth year of participation in the Roth 401(k) option, and (ii) attainment of age 59 ½, death or disability. The employer contribution will still be considered taxable income at the time of withdrawal.

Knight Inc. Cash Balance Retirement Plan. Employees of KMGP Services Company, Inc. and Knight, including our named executive officers, are also eligible to participate in a Cash Balance Retirement Plan. Certain employees continue to accrue benefits through a career-pay formula, "grandfathered" according to age and years of service on December 31, 2000, or collective bargaining arrangements. All other employees accrue benefits through a personal retirement account in the Cash Balance Retirement Plan. Under the plan, we make contributions on behalf of participating employees equal to 3% of eligible compensation every pay period. Interest is credited to the personal retirement accounts at the 30-year U.S. Treasury bond rate, or an approved substitute, in effect each year. Employees become fully vested in the plan after five years, and they may take a lump sum distribution upon termination of employment or retirement.

The following table sets forth the estimated actuarial present value of each named executive officer's accumulated pension benefit as of December 31, 2007, under the provisions of the Cash Balance Retirement Plan. With respect to our named executive officers, the benefits were computed using the same assumptions used for financial statement purposes, assuming current remuneration levels without any salary projection, and assuming participation until normal retirement at age sixty-five. These benefits are subject to federal and state income taxes, where applicable, but are not subject to deduction for social security or other offset amounts.

Name	Plan Name	Current Credited Yrs of Service	Pension Benefits Present Value of Accumulated Benefit(1)	Contributions During 2007
Richard D. Kinder	Cash Balance	7	$ —	$ —
Kimberly A. Dang	Cash Balance	6	31,408	7,294
Steven J. Kean	Cash Balance	6	41,724	7,767
Scott E. Parker	Cash Balance	9	71,515	9,130
C. Park Shaper	Cash Balance	7	51,079	8,194

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(1) The present values in the Pension Benefits table are based on certain assumptions-including a 5.75% discount rate, RP 2000 mortality (post-retirement only), 5% cash balance interest crediting rate, and lump sums calculated using a 5% interest rate and IRS mortality. We assumed benefits would commence at normal retirement date or unreduced retirement date, if earlier. No death or turnover was assumed prior to retirement date.

Other Potential Post-Employment Benefits. On October 7, 1999, Mr. Richard D. Kinder entered into an employment agreement with Knight pursuant to which he agreed to serve as its Chairman and Chief Executive Officer. His employment agreement provides for a term of three years and one year extensions on each anniversary of October 7^{th}. Mr. Kinder, at his initiative, accepted an annual salary of $1 to demonstrate his belief in our and Knight's long term viability. Mr. Kinder continues to accept an annual salary of $1, and he receives no other compensation from us. Mr. Kinder was awarded Class B units by and in Knight Holdco LLC in connection with Knight's going-private transaction, and while we, as a subsidiary of Knight Holdco LLC, are allocated compensation expense attributable to such Class B units, we have no obligation, nor do we expect, to pay any amounts in connection with the Class B units.

Knight believes that Mr. Kinder's employment agreement contains provisions that are beneficial to Knight and its subsidiaries and accordingly, Mr. Kinder's employment agreement is extended annually at the request of Knight and KMR's Board of Directors. For example, with limited exceptions, Mr. Kinder is prevented from competing in any manner with Knight or any of its subsidiaries, while he is employed by Knight and for 12 months following the termination of his employment with Knight. The agreement contains provisions that address termination with and without cause, termination as a result of change in duties or disability, and death. At his current compensation level, the maximum amount that would be paid to Mr. Kinder or his estate in the event of his termination is three times $750,000, or $2.25 million. This payment would be made if Mr. Kinder were terminated by Knight without cause or if Mr. Kinder terminated his employment with Knight as a result of a change in duties (as defined in the employment agreement). There are no employment agreements or change-in-control arrangements with any of our other executive officers.

Mr. Scott E. Parker elected to not participate in the going-private transaction. As a result, we offered Mr. Parker a retention agreement. The agreement was effective May 30, 2007, and lasts for three years. Mr. Parker is eligible for quarterly cash payments of $65,000, a one-time relocation payment of $100,000, and the right to participate in both the annual incentive plan and employee benefit plans. Under the terms of the agreement, Mr. Parker will also receive payments of $500,000 on May 30, 2008, $500,000 on May 30, 2009, and $2,000,000 on May 30, 2010, respectively, provided he is an active employee on each respective date. The agreement also contains confidential information, non-solicitation of employees and non-compete provisions.

Common Unit Option Plan. Pursuant to our Common Unit Option Plan, key personnel are eligible to receive grants of options to acquire common units. The total number of common units authorized under the option plan is 500,000. None of the options granted under the option plan may be "incentive stock options" under Section 422 of the Internal Revenue Code. If an option expires without being exercised, the number of common units covered by such option will be available for a future award. The exercise price for an option may not be less than the fair market value of a common unit on the date of grant. KMR's compensation committee determines the duration and vesting of the options to employees at the time of grant, and no individual employee may be granted options for more than 20,000 common units in any year. As of December 31, 2007, no options to purchase common units were outstanding under the plan. KMR's compensation committee administers the option plan, and the plan has a termination date of March 5, 2008.

For the year ended December 31, 2007, no options to purchase common units were granted to or exercised by any of our executive officers, and as of December 31, 2007, none of our executive officers owned unexercised common unit options. The plan may also grant, to each of our non-employee directors, options to purchase common units at an exercise price equal to the fair market value of the common units at the end of the trading day on such date. For the year ended December 31, 2007, no options to purchase common units were granted to our non-employee directors.

Summary Compensation Table

The following table shows compensation paid or otherwise awarded to (i) our principal executive officer; (ii) our principal financial officer; and (iii) our three most highly compensated executive officers (other than our principal executive officer and principal financial officer) serving at fiscal year end 2007 (collectively referred to as the "named executive officers") for services rendered to us, our subsidiaries or our affiliates, including Knight and Knight Holdco LLC (collectively referred to as the "Knight affiliated entities"), during fiscal years 2007 and 2006. The amounts in the columns below, except the column entitled "Unit Awards by Knight Holdco LLC", represent the total compensation paid or awarded to the named executive officers by all the Knight affiliated entities, and as a result the amounts are in excess of the compensation expense allocated to and recognized by us for services rendered to us. The amounts in the column entitled "Unit Awards by Knight Holdco LLC" consist of accounting expense calculated in accordance with SFAS No. 123R and allocated to us for the Knight Holdco LLC Class A-1 and Class B units awarded by Knight Holdco LLC to the named executive officers. As a subsidiary of Knight Holdco LLC, we are allocated a portion of the compensation expense recognized by Knight Holdco LLC with respect to such units, although none of us or any of our subsidiaries have any obligation, nor do we expect, to pay any amounts in respect of such units and none of the named executive officers has received any payments in respect of such units.

Name and Principal Position	Year	Salary	Bonus	(1) Stock Awards by KMI	(2) Option Awards by KMI	(3) Non-Equity Incentive Plan Compensation	(4) Change in Pension Value	(5) All Other Compensation	(6) Unit Awards by Knight Holdco LLC	Total
Richard D. Kinder	2007	$ 1	$ —	$ —	$ —	$ —	$ —	$ —	$ 1,016,000	$ 1,016,001
Director, Chairman and Chief Executive Officer	2006	1	—	—	—	—	—	—	—	1
Kimberly A. Dang	2007	200,000	—	338,095	—	400,000	7,294	32,253	73,800	1,051,442
Vice President and Chief Financial Officer	2006	200,000	—	139,296	37,023	270,000	6,968	46,253	—	699,540
Steven J. Kean	2007	200,000	—	4,397,080	—	1,100,000	7,767	147,130	295,010	6,146,987
Executive Vice President And Chief Operating Officer	2006	200,000	—	1,591,192	147,943	—	7,422	284,919	—	2,231,476
Scott E. Parker	2007	200,000	—	2,340,080	—	1,100,000	9,130	307,688	—	3,956,898
Vice President (President, Natural Gas Pipelines)	2006	200,000	350,000	881,317	29,490	500,000	8,735	164,630	—	2,134,172
C. Park Shaper	2007	200,000	—	1,950,300	—	1,200,000	8,194	155,953	466,110	3,980,557
Director and President	2006	200,000	—	1,134,283	24,952	—	7,835	348,542	—	1,715,612

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(1) Consists of expense calculated in accordance with SFAS No. 123R attributable to restricted KMI stock awarded in 2003, 2004 and 2005 according to the provisions of the KMI Stock Plan. No restricted stock was awarded in 2007 or 2006. For grants of restricted stock, we take the value of the award at time of grant and accrue the expense over the vesting period according to SFAS No. 123R. For grants made July 16, 2003—KMI closing price was $53.80, twenty-five percent of the shares in each grant vest on the third anniversary after the date of grant and the remaining seventy-five percent of the shares in each grant vest on the fifth anniversary after the date of grant. For grants made July 20, 2004—KMI closing price was $60.79, fifty percent of the shares vest on the third anniversary after the date of grant and the remaining fifty percent of the shares vest on the fifth anniversary after the date of grant. For grants made July 20, 2005—KMI closing price was $89.48, twenty-five percent of the shares in each grant vest on the third anniversary after the date of grant and the remaining seventy-five percent of the shares in each grant vest on the fifth anniversary after the date of grant. As a result of the KMI going-private transaction, all outstanding restricted shares vested in 2007 and therefore all remaining compensation expense with respect to restricted stock was recognized in 2007 in accordance with SFAS No. 123R. However, Knight bore all of the costs associated with this acceleration.

(2) Consists of expense calculated in accordance with SFAS No. 123R attributable to options to purchase KMI shares awarded in 2002 and 2003 according to the provisions of the KMI Stock Plan. No options were granted in 2007 or 2006. For options granted in 2002—volatility of 0.3912 using a 6 year term, 4.01% five year risk free interest rate return, and a 0.71% expected annual dividend rate. For options granted in 2003—volatility of 0.3853 using a 6.25 year term, 3.37% treasury strip quote at time of grant, and a 2.973% expected annual dividend rate. As a result of the KMI going-private transaction, all outstanding options vested in 2007 and therefore all remaining compensation expense with respect to options was recognized in 2007 in accordance with SFAS No. 123R. As a condition to their being permitted to participate in the KMI going-private transaction, Messrs. Kean and Shaper agreed to the cancellation of 10,467 and 22,031 options, respectively. These cancelled options had weighted average exercise prices of $39.12 and $24.75 per share, respectively. However, Knight bore all of the costs associated with this acceleration.

(3) Represents amounts paid according to the provisions of the Knight Annual Incentive Plan. In the case of Mr. Parker, for the year 2006, an additional $350,000 was paid outside of the plan, as reflected in the Bonus column. Amounts were earned in

the fiscal year indicated but were paid in the next fiscal year. Messrs. Kean and Shaper refused to accept a bonus for 2006. The committee agreed that this was not a reflection of performance on either person.

(4) Represents the 2007 and 2006, as applicable, change in the actuarial present value of accumulated defined pension benefit (including unvested benefits) according to the provisions of Knight's Cash Balance Retirement Plan.

(5) Amounts represent value of contributions to the Knight Savings Plan (a 401(k) plan), value of group-term life insurance exceeding $50,000, taxable parking subsidy and dividends paid on unvested restricted stock awards. Amounts each year include $10,000 representing the value of contributions to the Knight Savings Plan. Amounts representing the value of dividends paid on unvested restricted stock awards are as follows: for 2007—Mrs. Dang $21,875; Mr. Kean $136,500; Mr. Parker $77,000; and Mr. Shaper $144,375; for 2006—Mrs. Dang $35,875; Mr. Kean $273,000; Mr. Parker $154,000; and Mr. Shaper $336,875. Mr. Parker's 2007 amount also includes amounts for imputed income for company provided cellphone, a $100,000 relocation allowance, and a $130,000 payment to compensate for loss of dividends associated with the KMI going-private transaction.

(6) Such amounts represent the amount of the non-cash compensation expense calculated in accordance with SFAS No. 123R attributable to the Class A-1 and Class B units of Knight Holdco LLC and allocated to us for financial reporting purposes but does not include any such expense allocated to Knight or any of its other subsidiaries. None of the named executive officers has received any payments in connection with such units, and none of us or our subsidiaries are obligated, nor do we expect, to pay any amounts in respect of such units. See Item 13. "Certain Relationships and Related Transactions, and Director Independence—Related Transactions—KMI Going-Private Transaction" for further discussion of these units.

KMI Stock Options and Restricted Stock

Effective with the completion of the KMI going-private transaction on May 30, 2007, all of KMI's equity compensation awards (including awards held by our named executive officers) were subject to the following treatment:

- each option or other award to purchase shares of KMI common stock granted under any Kinder Morgan employee or director equity plan, whether vested or unvested, that was outstanding immediately prior to the effective time of the buyout, vested as of the effective time of the buyout, and was cancelled and converted into the right to receive a cash payment equal to the number of shares of KMI common stock underlying such options multiplied by the amount (if any) by which the $107.50 per share merger consideration issued in the going-private transaction exceeded the option exercise price, without interest and less any applicable withholding tax; and

- each share of restricted stock or restricted stock unit under any Kinder Morgan stock plan or benefit plan vested as of the effective time of the buyout and was cancelled and converted into the right to receive a cash payment equal to the number of outstanding shares of restricted stock or restricted stock units, multiplied by the $107.50 per share merger consideration, without interest and less any applicable withholding tax.

The following table sets forth, for each of our named executive officers (i) the number of KMI stock options (all of which were vested) held by such persons; (ii) the cash value realized with respect to such stock options upon consummation of the going-private transaction; (iii) the number of shares of restricted KMI stock held by such persons; and (iv) the aggregate cash value realized with respect to such shares of restricted stock upon consummation of the going-private transaction. A portion of the consideration received by the named executive officers with respect to their options to acquire shares of KMI common stock and their restricted shares of KMI common stock was reinvested in exchange for ownership interests in Knight Holdco LLC, and certain executive officers, as a condition to their being permitted to participate as investors in Knight Holdco LLC, agreed to the cancellation of certain of their options prior to the going-private transaction.

Name	Option Awards: Stock Options	Option Awards: Value Realized (1)	Stock Awards: Shares of Restricted Stock	Stock Awards: Value Realized (2)
Richard D. Kinder	—	$ —	—	$ —
Kimberly A. Dang	24,750	1,443,178	8,000	860,000
Steven J. Kean(3)	25,533	1,375,772	78,000	8,385,000
Scott E. Parker	10,000	537,000	44,000	4,730,000
C. Park Shaper(4)	197,969	12,529,810	82,500	8,868,750

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(1) Calculated based on the actual exercise prices underlying the related options, as opposed to the weighted average exercise price per share of options.

(2) Calculated as $107.50 multiplied by the number of shares of restricted stock.

(3) Mr. Kean, as a condition to his being permitted to participate as an investor in Knight, agreed to the cancellation of 10,467 of his options shown above, with a weighted average exercise price of $39.12 per share, prior to the going-private transaction.

(4) Mr. Shaper, as a condition to his being permitted to participate as an investor in Knight, agreed to the cancellation of 22,031 of his options shown above, with a weighted average exercise price of $24.75 per share, prior to the going-private transaction.

Grants of Plan-Based Awards

The following supplemental compensation table shows compensation details on the value of all non-guaranteed and non-discretionary incentive awards granted during 2007 to our named executive officers, as well as awards of Knight Holdco LLC units received in 2007 by each named executive officer. The table includes the Knight Holdco LLC Class A-1 and Class B units awarded by Knight Holdco LLC to the named executive officers. As a subsidiary of Knight Holdco LLC, we are allocated a portion of the compensation expense recognized by Knight Holdco LLC with respect to such units, although none of us or any of our subsidiaries have any obligation to pay any amounts in respect of such units. The table includes awards made during or for 2007. The information in the table under the caption "Estimated Possible Payments Under Non-Equity Incentive Plan Awards" represents the threshold, target and maximum amounts payable under the Knight Annual Incentive Plan for performance in 2007. Amounts actually paid under that plan for 2007 are set forth in the Summary Compensation Table under the caption "Non-Equity Incentive Plan Compensation." There will not be any additional payouts under the Annual Incentive Plan for 2007.

Name	Grant date	Estimated Possible Payouts Under Non-Equity Incentive Plan Awards[1]			All other stock awards[2]	Grant date fair value of stock awards[3]
		Threshold	Target	Maximum	Number of units	
Richard D. Kinder	May 30, 2007				791,405,452	$ 9,200,000
Kimberly A. Dang	January 17, 2007	$ 500,000	$ 1,000,000	$ 1,500,000		
	May 30, 2007				49,893,032	674,887
Steven J. Kean	January 17, 2007	750,000	1,500,000	2,000,000		
	May 30, 2007				162,114,878	2,720,252
Scott E. Parker	January 17, 2007	500,000	1,500,000	2,000,000		
C. Park Shaper	January 17, 2007	750,000	1,500,000	2,000,000		
	May 30, 2007				225,436,274	4,315,475

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1 Represents grants under the Knight Annual Incentive Plan for performance in 2007. See "Elements of Compensation—

Possible Annual Cash Bonus (Non-Equity Cash Incentive)" for a discussion of these awards.

2 Represents the sum of the number of Class A-1 units and the number of Class B units of Knight Holdco LLC awarded to the named executive officers in connection with the going-private transaction. See Item 13. "Certain Relationships and Related Transactions, and Director Independence—Related Transactions—KMI Going-Private Transaction" for detail regarding these awards.

3 Amounts represent the fair value calculated in accordance with SFAS No. 123R attributable to Class A-1 and Class B units of Knight Holdco LLC awarded by Knight Holdco LLC to the named executive officers in connection with the going-private transaction. None of the named executive officers has received any payments in connection with such units, and none of us or our subsidiaries are obligated to pay any amounts in respect of such units. See Item 13. "Certain Relationships and Related Transactions, and Director Independence—Related Transactions—KMI Going-Private Transaction" for further discussion of these units.

Outstanding Equity Awards at Fiscal Year-End

The only unvested equity awards outstanding at the end of fiscal 2007 were the Class B units of Knight Holdco LLC awarded by Knight Holdco LLC to the named executive officers. As a subsidiary of Knight Holdco LLC, we are allocated a portion of the compensation expense recognized by Knight Holdco LLC with respect to such units, although none of us or any of our subsidiaries have any obligation, nor do we expect, to pay any amounts in respect of such units.

	Stock awards:		
Name	**Type of units:**	**Number of units that have not vested**	**Market value of units of stock that have not vested[1]**
Richard D. Kinder	Class B units	791,405,452	N/A
Kimberly A. Dang	Class B units	49,462,841	N/A
Steven J. Kean	Class B units	158,281,090	N/A
C. Park Shaper	Class B units	217,636,499	N/A

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1 Because the Class B units are equity interests of Knight Holdco LLC, a private limited liability company, the market value of such interests is not readily determinable. None of the named executive officers has received any payments in connection with such units, and none of us or our subsidiaries are obligated, nor do we expect, to pay any amounts in respect of such units. See Item 13. "Certain Relationships and Related Transactions, and Director Independence—Related Transactions—KMI Going-Private Transaction" for further discussion of these units.

Director Compensation

Compensation Committee Interlocks and Insider Participation. The compensation committee of KMR functions as our compensation committee. KMR's compensation committee, comprised of Mr. Edward O. Gaylord, Mr. Gary L. Hultquist and Mr. Perry M. Waughtal, makes compensation decisions regarding the executive officers of our general partner and its delegate, KMR. Mr. Richard D. Kinder, Mr. James E. Street, and Messrs. Shaper and Kean, who are executive officers of KMR, participate in the deliberations of the KMR compensation committee concerning executive officer compensation. None of the members of KMR's compensation committee is or has been one of our officers or employees, and none of our executive officers served during 2007 on a board of directors of another entity which has employed any of the members of KMR's compensation committee.

Directors Fees. Beginning in 2005, awards under our Common Unit Compensation Plan for Non-Employee Directors served as compensation for each of KMR's three non-employee directors. In addition, directors are reimbursed for reasonable expenses in connection with board meetings. Directors of KMR who are also employees of Knight (Messrs. Richard D. Kinder and C. Park Shaper) do not receive compensation in their capacity as directors.

Kinder Morgan Energy Partners, L.P. Common Unit Compensation Plan for Non-Employee Directors. On January 18, 2005, KMR's compensation committee established the Kinder Morgan Energy Partners, L.P. Common

Unit Compensation Plan for Non-Employee Directors. The plan is administered by KMR's compensation committee and KMR's board has sole discretion to terminate the plan at any time. The primary purpose of this plan was to promote our interests and the interests of our unitholders by aligning the compensation of the non-employee members of the board of directors of KMR with unitholders' interests. Further, since KMR's success is dependent on its operation and management of our business and our resulting performance, the plan is expected to align the compensation of the non-employee members of the board with the interests of KMR's shareholders.

The plan recognizes that the compensation to be paid to each non-employee director is fixed by the KMR board, generally annually, and that the compensation is payable in cash. Pursuant to the plan, in lieu of receiving cash compensation, each non-employee director may elect to receive common units. Each election will be generally at or around the first board meeting in January of each calendar year and will be effective for the entire calendar year. The election for 2006 was made effective January 17, 2006; the election for 2007 was made effective January 17, 2007; and the election for 2008 was made effective January 16, 2008. A non-employee director may make a new election each calendar year. The total number of common units authorized under this compensation plan is 100,000.

Each annual election will be evidenced by an agreement, the Common Unit Compensation Agreement, between us and each non-employee director, and this agreement will contain the terms and conditions of each award. Pursuant to this agreement, all common units issued under this plan are subject to forfeiture restrictions that expire six months from the date of issuance. Until the forfeiture restrictions lapse, common units issued under the plan may not be sold, assigned, transferred, exchanged, or pledged by a non-employee director. In the event the director's service as a director of KMR is terminated prior to the lapse of the forfeiture restriction either for cause, or voluntary resignation, each director will, for no consideration, forfeit to us all common units to the extent then subject to the forfeiture restrictions. Common units with respect to which forfeiture restrictions have lapsed will cease to be subject to any forfeiture restrictions, and we will provide each director a certificate representing the units as to which the forfeiture restrictions have lapsed. In addition, each non-employee director will have the right to receive distributions with respect to the common units awarded to him under the plan, to vote such common units and to enjoy all other unitholder rights, including during the period prior to the lapse of the forfeiture restrictions.

The number of common units to be issued to a non-employee director electing to receive the cash compensation in the form of common units will equal the amount of such cash compensation awarded, divided by the closing price of the common units on the New York Stock Exchange on the day the cash compensation is awarded (such price, the fair market value), rounded down to the nearest 50 common units. The common units will be issuable as specified in the Common Unit Compensation Agreement. A non-employee director electing to receive the cash compensation in the form of common units will receive cash equal to the difference between (i) the cash compensation awarded to such non-employee director and (ii) the number of common units to be issued to such non-employee director multiplied by the fair market value of a common unit. This cash payment will be payable in four equal installments generally around March 31, June 30, September 30 and December 31 of the calendar year in which such cash compensation is awarded.

On January 17, 2007, each of KMR's three non-employee directors was awarded cash compensation of $160,000 for board service during 2007. Effective January 17, 2007, each non-employee director elected to receive certain amounts of that compensation in the form of our common units and each was issued common units pursuant to the plan and its agreements (based on the $48.44 closing market price of our common units on January 17, 2007, as reported on the New York Stock Exchange). Mr. Gaylord elected to receive compensation of $95,911.20 in the form of our common units and was issued 1,980 common units; Mr. Waughtal elected to receive compensation of $159,852.00 in the form of our common units and was issued 3,300 common units; and Mr. Hultquist elected to receive cash compensation of $96,880.00 in the form of our common units and was issued 2,000 common units. All remaining compensation ($64,088.80 to Mr. Gaylord; $148.00 to Mr. Waughtal; and $63,120.00 to Mr. Hultquist) will be paid in cash to each of the non-employee directors as described above, and no other compensation will be paid to the non-employee directors during 2007.

On January 16, 2008, each of KMR's three non-employee directors was awarded cash compensation of $160,000 for board service during 2008; however, during a plan audit it was determined that each director was inadvertently paid an additional dividend in 2007. As a result, each director's cash compensation for service during 2008 was adjusted downward to reflect this error. The correction results in cash compensation awarded for 2008 in the amounts of $158,380.00 for Mr. Hultquist; $158,396.20 for Mr. Gaylord; and $157,327.00 for Mr. Waughtal.

Effective January 16, 2008, two of the three non-employee directors elected to receive certain amounts of that compensation in the form of our common units and each was issued common units pursuant to the plan and its agreements (based on the $55.81 closing market price of our common units on January 16, 2008, as reported on the New York Stock Exchange). Mr. Gaylord elected to receive compensation of $84,831.20 in the form of our common units and was issued 1,520 common units; and Mr. Waughtal elected to receive compensation of $157,272.58 in the form of our common units and was issued 2,818 common units. All remaining compensation ($73,565.00 to Mr. Gaylord; $54.42 to Mr. Waughtal; and $158,380.00 to Mr. Hultquist) will be paid in cash to each of the non-employee directors as described above, and no other compensation will be paid to the non-employee directors during 2008.

Directors' Unit Appreciation Rights Plan. On April 1, 2003, KMR's compensation committee established our Directors' Unit Appreciation Rights Plan. Pursuant to this plan, each of KMR's three non-employee directors was eligible to receive common unit appreciation rights. Upon the exercise of unit appreciation rights, we will pay, within thirty days of the exercise date, the participant an amount of cash equal to the excess, if any, of the aggregate fair market value of the unit appreciation rights exercised as of the exercise date over the aggregate award price of the rights exercised. The fair market value of one unit appreciation right as of the exercise date will be equal to the closing price of one common unit on the New York Stock Exchange on that date. The award price of one unit appreciation right will be equal to the closing price of one common unit on the New York Stock Exchange on the date of grant. Proceeds, if any, from the exercise of a unit appreciation right granted under the plan will be payable only in cash (that is, no exercise will result in the issuance of additional common units) and will be evidenced by a unit appreciation rights agreement.

All unit appreciation rights granted vest on the six-month anniversary of the date of grant. If a unit appreciation right is not exercised in the ten year period following the date of grant, the unit appreciation right will expire and not be exercisable after the end of such period. In addition, if a participant ceases to serve on the board for any reason prior to the vesting date of a unit appreciation right, such unit appreciation right will immediately expire on the date of cessation of service and may not be exercised.

On April 1, 2003, the date of adoption of the plan, each of KMR's three non-employee directors was granted 7,500 unit appreciation rights. In addition, 10,000 unit appreciation rights were granted to each of KMR's three non-employee directors on January 21, 2004, at the first meeting of the board in 2004. During the first board meeting of 2005, the plan was terminated and replaced by the Kinder Morgan Energy Partners, L.P. Common Unit Compensation Plan for Non-Employee Directors; however, all unexercised awards made under the plan remain outstanding. No unit appreciation rights were exercised during 2006. In 2007, Mr. Hultquist exercised 7,500 unit appreciation rights and received a cash amount of $116,250. As of December 31, 2007, 45,000 unit appreciation rights had been granted, vested and remained outstanding.

The following table discloses the compensation earned by each of KMR's three non-employee directors for board service during fiscal year 2007. In addition, directors are reimbursed for reasonable expenses in connection with board meetings. Directors of KMR who are also employees of Knight do not receive compensation in their capacity as directors.

Name	Fees Earned or Paid in Cash	Common Unit Awards(1)	All Other Compensation(2)	Total
Edward O. Gaylord	$ 64,089	$ 95,911	$ 111,466	$ 271,466
Gary L. Hultquist	63,120	96,880	65,840	225,840
Perry M. Waughtal	148	159,852	114,726	274,726

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(1) Represents the value of cash compensation received in the form of our common units according to the provisions of our Common Unit Compensation Plan for Non-Employee Directors. Value computed as the number of common units elected to be received in lieu of cash times the closing price on date of election. For Mr. Gaylord, 1,980 units elected on January 17, 2007 times the closing price of $48.44; for Mr. Hultquist, 2,000 units elected times the closing price of $48.44; and for Mr. Waughtal, 3,300 units elected times the closing price of $48.44.

(2) For each, represents (i) the value of common unit appreciation rights earned according to the provisions of our Directors' Unit Appreciation Rights Plan for Non-Employee Directors, determined according to the provisions of SFAS No. 123R—for each common unit appreciation right, equal to the increase in value of a corresponding common unit from December 31, 2006 to December 31, 2007; and (ii) distributions paid on unvested common units awarded according to the provisions of our Common Unit Compensation Plan for Non-Employee Directors.

For 2007, for Mr. Gaylord, includes (i) value of $106,575 computed as the number of common unit appreciation rights held during 2007 (17,500) times the increase in common unit closing price from December 31, 2006 to December 31, 2007 ($6.09; equal to $53.99 at December 31, 2007 less $47.90 at December 31, 2006); and (ii) $4,891 for distributions paid on unvested common units awarded according to the provisions of our Common Unit Compensation Plan for Non-Employee Directors; for Mr. Hultquist, includes (i) value of $60,900 computed as the number of common unit appreciation rights held during 2007 (10,000) times the increase in common unit closing price from December 31, 2006 to December 31, 2007 ($6.09; equal to $53.99 at December 31, 2007 less $47.90 at December 31, 2006); and (ii) $4,940 for distributions paid on unvested common units awarded according to the provisions of our Common Unit Compensation Plan for Non-Employee Directors; for Mr. Waughtal, includes (i) value of $106,575 computed as the number of common unit appreciation rights held during 2007 (17,500) times the increase in common unit closing price from December 31, 2006 to December 31, 2007 ($6.09; equal to $53.99 at December 31, 2007 less $47.90 at December 31, 2006); and (ii) $8,151 for distributions paid on unvested common units awarded according to the provisions of our Common Unit Compensation Plan for Non-Employee Directors.

Compensation Committee Report

Throughout fiscal 2007, the compensation committee of KMR's board of directors was comprised of three directors, each of which the KMR board of directors has determined meets the criteria for independence under KMR's governance guidelines and the New York Stock Exchange rules.

The KMR compensation committee has discussed and reviewed the above Compensation Discussion and Analysis for fiscal year 2007 with management. Based on this review and discussion, the KMR compensation committee recommended to its board of directors, that this Compensation Discussion and Analysis be included in this annual report on Form 10-K for the fiscal year 2007.

KMR Compensation Committee:
Edward O. Gaylord
Gary L. Hultquist
Perry M. Waughtal

Item 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.***

The following table sets forth information as of January 31, 2008, regarding (i) the beneficial ownership of (a) our common and Class B units and (b) KMR shares by all directors of our general partner and KMR, its delegate, by each of the named executive officers identified in Item 11 "Executive Compensation" and by all directors and executive officers as a group; and (ii) the beneficial ownership of our common and Class B units or shares of KMR by all persons known by our general partner to own beneficially at least 5% of our common and Class B units and KMR shares. For information regarding the beneficial ownership of Knight Holdco LLC's units by our named executive officers (and our executive officers who are also officers of Knight) and directors, see Item 13. "Certain Relationships and Related Transactions, and Director Independence—Related Transactions—KMI Going-Private Transaction." Unless otherwise noted, the address of each person below is c/o Kinder Morgan Energy Partners, L.P., 500 Dallas Street, Suite 1000, Houston, Texas 77002.

Amount and Nature of Beneficial Ownership(1)

	Common Units		**Class B Units**		**Kinder Morgan Management Shares**	
	Number of Units(2)	**Percent of Class**	**Number of Units(3)**	**Percent of Class**	**Number of Shares(4)**	**Percent of Class**
Richard D. Kinder(5)	315,979	*	—	—	84,663	*
C. Park Shaper	4,000	*	—	—	23,793	*
Edward O. Gaylord(6)	40,000	*	—	—	—	—
Gary L. Hultquist	11,500	*	—	—	—	—
Perry M. Waughtal(7)	46,918	*	—	—	46,180	*
Steven J. Kean	—	—	—	—	—	—
Scott E. Parker	—	—	—	—	—	—
Kimberly A. Dang	121	*	—	—	440	*
Directors and Executive Officers as a group (14 persons)(8)	435,995	*	—	—	175,027	*
Knight Inc.(9)	14,355,735	8.43%	5,313,400	100.00%	10,334,746	14.27%
Kayne Anderson Capital Advisors,L.P. and Richard A. Kayne(10)	—	—	—	—	7,869,016	10.86%
Tortoise Capital Advisors, L.L.C.(11)	—	—	—	—	4,314,123	5.96%
Janus Capital Management LLC(12)	—	—	—	—	3,647,958	5.04%

* Less than 1%.

(1) Except as noted otherwise, all units and KMR shares involve sole voting power and sole investment power. For KMR, see note (4). On January 18, 2005, KMR's board of directors initiated a rule requiring each director to own a minimum of 10,000 common units, KMR shares, or a combination thereof.

(2) As of January 31, 2008, we had 170,224,734 common units issued and outstanding.

(3) As of January 31, 2008, we had 5,313,400 Class B units issued and outstanding.

(4) Represent the limited liability company shares of KMR. As of January 31, 2008, there were 72,432,482 issued and outstanding KMR shares, including two voting shares owned by our general partner. In all cases, our i-units will be voted in proportion to the affirmative and negative votes, abstentions and non-votes of owners of KMR shares. Through the provisions in our partnership agreement and KMR's limited liability company agreement, the number of outstanding KMR shares, including voting shares owned by our general partner, and the number of our i-units will at all times be equal.

(5) Includes 7,879 common units owned by Mr. Kinder's spouse. Mr. Kinder disclaims any and all beneficial or pecuniary interest in these units.

(6) Includes 1,520 restricted common units.

(7) Includes 2,818 restricted common units.

(8) Includes 4,338 restricted common units. Also includes 671 KMR shares purchased by one of our executives for his children. The executive disclaims any beneficial ownership in such KMR shares.

(9) Includes common units owned by Knight Inc. and its consolidated subsidiaries, including 1,724,000 common units owned by Kinder Morgan G.P., Inc.

(10) As reported on the Schedule 13G/A filed February 13, 2008 by Kayne Anderson Capital Advisors, L.P. and Richard A. Kayne. Kayne Anderson Capital Advisors, L.P. reported that in regard to KMR shares, it had sole voting power over 0

shares, shared voting power over 7,867,883 shares, sole disposition power over 0 shares and shared disposition power over 7,867,883 shares. Mr. Kayne reports that in regard to KMR shares, he had sole voting power over 1,133 shares, shared voting power over 7,867,883 shares, sole disposition power over 1,133 shares and shared disposition power over 7,867,883 shares. Kayne Anderson Capital Advisors, L.P.'s and Richard A. Kayne's address is 1800 Avenue of the Stars, Second Floor, Los Angeles, California 90067.

(11) As reported on the Schedule 13G/A filed February 12, 2008 by Tortoise Capital Advisors, L.L.C. Tortoise Capital Advisors, L.L.C. reported that in regard to KMR shares, it had sole voting power over 0 shares, shared voting power over 4,202,836 shares, sole disposition power over 0 shares and shared disposition power over 4,314,123 shares. Tortoise Capital Advisors, L.L.C.'s address is 10801 Mastin Blvd., Suite 222, Overland Park, Kansas 66210.

(12) As reported on the Schedule 13G filed February 14, 2008 by Janus Capital Management LLC. Janus Capital Management LLC reported that in regard to KMR shares, it had sole voting power over 3,647,958 shares, shared voting power over 0 shares, sole disposition power over 3,647,958 shares and shared disposition power over 0 shares. Janus Capital Management LLC's address is 151 Detroit Street, Denver, Colorado 80206.

Equity Compensation Plan Information

The following table sets forth information regarding our equity compensation plans as of December 31, 2007. Specifically, the table provides information regarding our Common Unit Option Plan and our Common Unit Compensation Plan for Non-Employee Directors, both described in Item 11, "Executive Compensation.—Compensation Discussion and Analysis—Elements of Compensation—Other Compensation—Common Unit Option Plan," Item 11 "Executive Compensation—Director Compensation—Kinder Morgan Energy Partners, L.P. Common Unit Compensation Plan for Non-Employee Directors," and Note 13 of the notes to our consolidated financial statements included elsewhere in this report.

Plan category	Number of securities remaining available for future issuance under equity compensation plans
Equity compensation plans approved by security holders	—
Equity compensation plans not approved by security holders	141,820
Total	141,820

Item 13. ***Certain Relationships and Related Transactions, and Director Independence.***

Related Transactions

KMI Going-Private Transaction

On May 30, 2007, KMI completed the going-private transaction, whereby pursuant to a merger agreement, generally each share of KMI common stock was converted into the right to receive $107.50 in cash without interest. See Item 11. "Executive Compensation—KMI Stock Options and Restricted Stock" for a discussion of the disposition of options to purchase KMI common stock and shares of restricted KMI stock in the going-private transaction. For further information regarding this transaction, see "(a) General Development of Business" within Items 1 and 2 of this report.

In connection with the going-private transaction, some of our executive officers became investors in Knight Holdco LLC, Knight's parent company. None of our independent directors, Messrs. Gaylord, Hultquist and Waughtal, are investors in Knight Holdco LLC. Each of the investors in Knight Holdco LLC entered into an amended and restated limited liability company agreement of Knight Holdco LLC which governs the rights and obligations of the investors with respect to Knight Holdco LLC and Knight. Pursuant to the limited liability company agreement, Knight Holdco LLC is a "manager managed" limited liability company governed by an 11 member board of managers and initially by a "chief manager." Mr. Richard D. Kinder, our Chairman and Chief Executive Officer, is Knight Holdco LLC's initial chief manager. Mr. Kinder is also a member of the board of managers and has the right to appoint an additional four members of the board of managers. The chief manager has control over most of the operations of Knight Holdco LLC, subject to rights of the board of managers (and in some cases, the members of Knight Holdco LLC, acting in their capacity as such) to approve significant actions proposed to be taken by Knight Holdco LLC or its subsidiaries (generally other than us, KMR and our respective subsidiaries), including, among other things, liquidations, issuances of equity securities, distributions (other than identified tax related distributions), transactions with affiliates, settlement of litigation or entry into agreements with a value in excess of $50 million, entry into new lines of business and approval of the annual budget. Additionally, the members of Knight Holdco LLC (and in some cases, just certain members) have the ability to compel restructuring and liquidity events, including an initial public offering of Knight Holdco LLC or any of its subsidiaries or businesses, a sale or disposition of Knight Holdco LLC or any of its material subsidiaries or its businesses, or distributions of excess cash to the members of Knight Holdco LLC, although in some cases such actions may only be so compelled after specified time periods.

Generally, Knight Holdco LLC has three classes of units—Class A units, Class A-1 units, and Class B units. The Class A units were issued to investors, including members of senior management who directly or indirectly reinvested all or a portion of their KMI equity and/or cash, in respect of their capital contributions to Knight Holdco LLC. Generally, the holders of Class A units will share ratably in all distributions, subject to amounts allocated to the Class A-1 units and the Class B units as set forth below.

The Class B units were awarded by Knight Holdco LLC to members of Knight's management in consideration of their services to or for the benefit of Knight Holdco LLC. The Class B units represent interests in the profits of Knight Holdco LLC following the return of capital for the holders of Class A units and the achievement of predetermined performance targets over time. The Class B units will performance vest in increments of 5% of profits distributions up to a maximum of 20% of all profits distributions that would otherwise be payable with respect to the Class A units and Class A-1 units, based on the achievement of predetermined performance targets. The Class B units are subject to time based vesting, and with respect to any holder thereof, will vest 33 1/3% on each of the 3rd, 4th and 5th year anniversary of the issuance of such Class B units to such holder. The amended and restated limited liability company agreement also includes provisions with respect to forfeiture of Class B units upon termination for cause, Knight Holdco LLC's call rights upon termination and other related provisions relating to an employee's tenure. The allocation of the Class B units among Knight's management was determined prior to closing by Mr. Kinder, and approved by other, non-management investors.

The Class A-1 units were awarded by Knight Holdco LLC to members of Knight's management (other than Mr. Richard D. Kinder) who reinvested their equity interests in Knight Holdco LLC in connection with the going-private transaction in consideration of their services to or for the benefit of Knight Holdco LLC. Class A-1 units entitle a holder thereof to receive distributions from Knight Holdco LLC in an amount equal to distributions paid on Class A units (other than distributions on the Class A units that represent a return of the capital contributed in respect of such Class A units), but only after the Class A units have received aggregate distributions in an amount equal to the amount of capital contributed in respect of the Class A units.

The table below sets forth the beneficial ownership (as defined in Rule 13(d)(3) of the Exchange Act) of Knight Holdco LLC's units by each of our directors and named executive officers (and executive officers of ours who are also executive officers of Knight), detailing the contributions made by each in respect of their Class A units and the grant date fair value, as calculated in accordance with SFAS No. 123R, of the Class A-1 and Class B units received by each. In accordance with SFAS No. 123R, Knight Holdco LLC is required to recognize compensation expense in connection with the Class A-1 and Class B units over the expected life of such units. As a subsidiary of Knight Holdco LLC, we are allocated a portion of this compensation expense, although none of us or any of our subsidiaries have any obligation, nor do we expect, to pay any amounts in respect of such units. Please see Item 11. "Executive Compensation" for disclosure regarding the Class A-1 and Class B units received by each of the named executive officers and the expense as calculated in accordance with SFAS No. 123R allocated to us for 2007 in respect of each officer's units. Except as noted otherwise, each individual has sole voting power and sole disposition power over the units listed.

	Class A Units	% of Class A Units(1)	Class A-1 Units	% of Class A-1 Units(2)	Class B Units	% of Class B Units(3)
Richard D. Kinder(4)	2,424,000,000	30.6	–	–	791,405,452	40.0
Edward O. Gaylord	–	–	–	–	–	–
Gary L. Hultquist	–	–	–	–	–	–
Perry M. Waughtal	–	–	–	–	–	–
C. Park Shaper(5)	13,598,785	*	7,799,775	28.3	217,636,499	11.0
Steven J. Kean(6)	6,684,149	*	3,833,788	13.9	158,281,090	8.0
Kimberly A. Dang(7)	750,032	*	430,191	1.6	49,462,841	2.5
David D. Kinder(8)	1,075,981	*	617,144	2.3	55,398,382	2.8
Joseph Listengart(9)	6,059,449	*	3,475,483	12.6	79,140,545	4.0
Scott E. Parker	–	–	–	–	–	–
James E. Street(10)	3,813,005	*	2,187,003	7.9	49,462,841	2.5
Executive officers and directors as a group (14 persons)	2,460,763,539	31.1	21,086,247	76.5	1,626,338,205	82.2

* Less than 1%.

(1) As of January 31, 2008, Knight Holdco LLC had 7,914,367,913 Class A Units issued and outstanding.

(2) As of January 31, 2008, Knight Holdco LLC had 27,225,694 Class A-1 Units issued and outstanding and 345,042 phantom Class A-1 Units issued and outstanding. The phantom Class A-1 Units were issued to Canadian management employees.

(3) As of January 31, 2008, Knight Holdco LLC had 1,922,620,621 Class B Units issued and outstanding and 55,893,008 phantom Class B Units issued and outstanding. The phantom Class B Units were issued to Canadian management employees.

(4) Includes 522,372 Class A units owned by Mr. Kinder's wife. Mr. Kinder disclaims any and all beneficial or pecuniary interest in the Class A units held by his wife. Also includes 263,801,817 Class B Units that Mr. Kinder transferred to a limited partnership. Mr. Kinder may be deemed to be the beneficial owner of these transferred Class B Units, because Mr. Kinder controls the voting and disposition power of these Class B Units, but he disclaims ninety-nine percent of any beneficial and pecuniary interest in them. Mr. Kinder contributed 23,994,827 shares of KMI common stock and his wife contributed 5,173 shares of KMI common stock to Knight Holdco LLC that were valued for purposes of Knight Holdco LLC's limited liability agreement at $2,423,477,628 and $522,372, respectively, in exchange for their respective Class A units. The Class B units received by Mr. Kinder had a grant date fair value as calculated in accordance with SFAS No. 123R of $9,200,000.

(5) Includes 217,636,499 Class B Units that Mr. Shaper transferred to a limited partnership. Mr. Shaper may be deemed to be the beneficial owner of these transferred Class B Units, because Mr. Shaper controls the voting and disposition power of these Class B Units, but he disclaims approximately twenty-two percent of any beneficial and pecuniary interest in them. Mr. Shaper made a cash investment of $13,598,785 of his after-tax proceeds from the conversion in the going-private transaction of 82,500 shares of KMI restricted stock and options to acquire 197,969 shares of KMI common stock in exchange for his Class A units. The Class A-1 units and Class B units received by Mr. Shaper had an aggregate grant date fair value as calculated in accordance with SFAS No. 123R of $4,315,475.

(6) Mr. Kean made a cash investment of $6,684,149 of his after-tax proceeds from the conversion in the going-private transaction of 78,000 shares of KMI restricted stock and options to acquire 25,533 shares of KMI common stock in exchange for his Class A units. The Class A-1 units and Class B units received by Mr. Kean had an aggregate grant date fair value as calculated in accordance with SFAS No. 123R of $2,720,252.

(7) Includes 49,462,841 Class B Units that Ms. Dang transferred to a limited partnership. Ms. Dang may be deemed to be the beneficial owner of these transferred Class B Units, because Ms. Dang has voting and disposition power of these Class B Units, but she disclaims ten percent of any beneficial and pecuniary interest in them. Ms. Dang made a cash investment of $750,032 of her after-tax proceeds from the conversion in the going-private transaction of 8,000 shares of KMI restricted stock and options to acquire 24,750 shares of KMI common stock in exchange for her Class A units. The Class A-1 units and Class B units received by Ms. Dang had an aggregate grant date fair value as calculated in accordance with SFAS No. 123R of $674,887.

(8) Includes 55,398,382 Class B Units that Mr. Kinder transferred to a limited partnership. Mr. Kinder may be deemed to be the benficial owner of these transferred Class B Units, because Mr. Kinder controls the voting and disposition power of these Class B Units, but he disclaims eight percent of any benficial and pecuniary interest in them. Mr. Kinder made a cash investment of $1,075,981 of his after-tax proceeds from the conversion in the going-private transaction of 15,750 shares of KMI restricted stock in exchange for his Class A units. The Class A-1 units and Class B units received by Mr. Kinder had an aggregate grant date fair value as calculated in accordance with SFAS No. 123R of $787,587.

(9) Mr. Listengart made a cash investment of $6,059,449 of his after-tax proceeds from the conversion in the going-private transaction of 52,500 shares of KMI restricted stock and options to acquire 48,459 shares of KMI common stock in exchange for his Class A units. The Class A-1 units and Class B units received by Mr. Listengart had an aggregate grant date fair value as calculated in accordance with SFAS No. 123R of $1,712,851.

(10) Mr. Street made a cash investment of $3,813,005 of his after-tax proceeds from the conversion in the going-private transaction of 30,000 shares of KMI restricted stock and options to acquire 34,588 shares of KMI common stock in exchange for his Class A units. The Class A-1 units and Class B units received by Mr. Street had an aggregate grant date fair value as calculated in accordance with SFAS No. 123R of $1,074,434.

Other

Our policy is that (i) employees must obtain authorization from the appropriate business unit president of the relevant company or head of corporate function, and (ii) directors, business unit presidents, executive officers and heads of corporate functions must obtain authorization from the non-interested members of the audit committee of the applicable board of directors, for any business relationship or proposed business transaction in which they or an immediate family member has a direct or indirect interest, or from which they or an immediate family member may derive a personal benefit (a "related party transaction"). The maximum dollar amount of related party transactions that may be approved as described above in this paragraph in any calendar year is $1.0 million. Any related party transactions that would bring the total value of such transactions to greater than $1.0 million must be referred to the audit committee of the appropriate board of directors for approval or to determine the procedure for approval.

For information regarding other related transactions, see Note 12 of the notes to our consolidated financial statements included elsewhere in this report.

Director Independence

Our limited partnership agreement provides for us to have a general partner rather than a board of directors. Pursuant to a delegation of control agreement, our general partner delegated to KMR, to the fullest extent permitted under Delaware law and our partnership agreement, all of its power and authority to manage and control our business and affairs, except that KMR cannot take certain specified actions without the approval of our general partner. Through the operation of that agreement and our partnership agreement, KMR manages and controls our business and affairs, and the board of directors of KMR performs the functions of and acts as our board of directors. Similarly, the standing committees of KMR’s board of directors function as standing committees of our board. KMR’s board of directors is comprised of the same persons who comprise our general partner’s board of directors. References in this report to the board mean KMR’s board, acting as our board of directors, and references to committees mean KMR’s committees, acting as committees of our board of directors.

The board has adopted governance guidelines for the board and charters for the audit committee, nominating and governance committee and compensation committee. The governance guidelines and the rules of the New York Stock Exchange require that a majority of the directors be independent, as described in those guidelines, the committee charters and rules, respectively. Copies of the guidelines and committee charters are available on our internet website at www.kindermorgan.com. To assist in making determinations of independence, the board has determined that the following categories of relationships are not material relationships that would cause the affected director not to be independent:

- if the director was an employee, or had an immediate family member who was an executive officer, of KMR or us or any of its or our affiliates, but the employment relationship ended more than three years prior to the date of determination (or, in the case of employment of a director as an interim chairman, interim chief executive officer or interim executive officer, such employment relationship ended by the date of determination);

- if during any twelve month period within the three years prior to the determination the director received no more than, and has no immediate family member that received more than, $100,000 in direct compensation from us or our affiliates, other than (i) director and committee fees and pension or other forms of deferred compensation for prior service (provided such compensation is not contingent in any way on continued service), (ii) compensation received by a director for former service as an interim chairman, interim chief executive officer or interim executive officer, and (iii) compensation received by an immediate family member for service as an employee (other than an executive officer);

- if the director is at the date of determination a current employee, or has an immediate family member that is at the date of determination a current executive officer, of another company that has made payments to, or received payments from, us and our affiliates for property or services in an amount which, in each of the three fiscal years prior to the date of determination, was less than the greater of $1.0 million or 2% of such other company's annual consolidated gross revenues. Contributions to tax-exempt organizations are not considered payments for purposes of this determination;

- if the director is also a director, but is not an employee or executive officer, of our general partner or another affiliate or affiliates of KMR or us, so long as such director is otherwise independent; and

- if the director beneficially owns less than 10% of each class of voting securities of us, our general partner, or KMR.

The board has affirmatively determined that Messrs. Gaylord, Hultquist and Waughtal, who constitute a majority of the directors, are independent as described in our governance guidelines and the New York Stock Exchange rules. Each of them meets the standards above and has no other relationship with us. In conjunction with all regular quarterly and certain special board meetings, these three non-management directors also meet in executive session without members of management. In January 2008, Mr. Waughtal was elected for a one year term to serve as lead director to develop the agendas for and preside at these executive sessions of independent directors.

The governance guidelines and our audit committee charter, as well as the rules of the New York Stock Exchange and the Securities and Exchange Commission, require that members of the audit committee satisfy independence requirements in addition to those above. The board has determined that all of the members of the audit committee are independent as described under the relevant standards.

Item 14. ***Principal Accounting Fees and Services***

The following sets forth fees billed for the audit and other services provided by PricewaterhouseCoopers LLP for the fiscal years ended December 31, 2007 and 2006 (in dollars):

	Year Ended December 31,	
	2007	2006
Audit fees(1)	$ 2,070,205	$ 2,038,215
Tax fees(2)	2,563,793	1,470,466
Total	$ 4,633,998	$ 3,508,681

(1) Includes fees for integrated audit of annual financial statements and internal control over financial reporting, reviews of the related quarterly financial statements, and reviews of documents filed with the Securities and Exchange Commission.

(2) For 2007 and 2006, amounts include fees of $2,352,533 and $1,356,399, respectively, billed for professional services rendered for tax processing and preparation of Forms K-1 for our unitholders. Amounts also include fees of $211,260 and $114,067, respectively, billed for professional services rendered for tax return review services and for general state, local and foreign tax compliance and consulting services.

All services rendered by PricewaterhouseCoopers LLP are permissible under applicable laws and regulations, and were pre-approved by the audit committee of KMR and our general partner. Pursuant to the charter of the audit committee of KMR, the delegate of our general partner, the committee's primary purposes include the following: (i) to select, appoint, engage, oversee, retain, evaluate and terminate our external auditors; (ii) to pre-approve all audit and non-audit services, including tax services, to be provided, consistent with all applicable laws, to us by our external auditors; and (iii) to establish the fees and other compensation to be paid to our external auditors. The audit committee has reviewed the external auditors' fees for audit and non audit services for fiscal year 2007. The audit committee has also considered whether such non audit services are compatible with maintaining the external auditors' independence and has concluded that they are compatible at this time.

Furthermore, the audit committee will review the external auditors' proposed audit scope and approach as well as the performance of the external auditors. It also has direct responsibility for and sole authority to resolve any disagreements between our management and our external auditors regarding financial reporting, will regularly review with the external auditors any problems or difficulties the auditors encountered in the course of their audit work, and will, at least annually, use its reasonable efforts to obtain and review a report from the external auditors addressing the following (among other items): (i) the auditors' internal quality-control procedures; (ii) any material issues raised by the most recent internal quality-control review, or peer review, of the external auditors; (iii) the independence of the external auditors; and (iv) the aggregate fees billed by our external auditors for each of the previous two fiscal years.

PART IV

Item 15. ***Exhibits and Financial Statement Schedules***

(a)(1) and (2) *Financial Statements and Financial Statement Schedules*

See "Index to Financial Statements" set forth on page 114.

(a)(3) *Exhibits*

*3.1 — Third Amended and Restated Agreement of Limited Partnership of Kinder Morgan Energy Partners, L.P. (filed as Exhibit 3.1 to Kinder Morgan Energy Partners, L.P. Form 10-Q (File No. 1-11234) for the quarter ended June 30, 2001, filed on August 9, 2001).

*3.2 — Amendment No. 1 dated November 19, 2004 to Third Amended and Restated Agreement of Limited Partnership of Kinder Morgan Energy Partners, L.P. (filed as Exhibit 99.1 to Kinder Morgan Energy Partners, L.P. Form 8-K, filed November 22, 2004).

*3.3 — Amendment No. 2 to Third Amended and Restated Agreement of Limited Partnership of Kinder Morgan Energy Partners, L.P. (filed as Exhibit 99.1 to Kinder Morgan Energy Partners, L.P. Form 8-K, filed May 5, 2005).

*4.1 — Specimen Certificate evidencing Common Units representing Limited Partner Interests (filed as Exhibit 4.1 to Amendment No. 1 to Kinder Morgan Energy Partners, L.P. Registration Statement on Form S-4, File No. 333-44519, filed on February 4, 1998).

*4.2 — Indenture dated as of January 29, 1999 among Kinder Morgan Energy Partners, L.P., the guarantors listed on the signature page thereto and U.S. Trust Company of Texas, N.A., as trustee, relating to Senior Debt Securities (filed as Exhibit 4.1 to the Partnership's Current Report on Form 8-K filed February 16, 1999, File No. 1-11234 (the "February 16, 1999 Form 8-K")).

*4.3 — First Supplemental Indenture dated as of January 29, 1999 among Kinder Morgan Energy Partners, L.P., the subsidiary guarantors listed on the signature page thereto and U.S. Trust Company of Texas, N.A., as trustee, relating to $250,000,000 of 6.30% Senior Notes due February 1, 2009 (filed as Exhibit 4.2 to the February 16, 1999 Form 8-K (File No. 1-11234)).

*4.4 — Second Supplemental Indenture dated as of September 30, 1999 among Kinder Morgan Energy Partners, L.P. and U.S. Trust Company of Texas, N.A., as trustee, relating to release of subsidiary guarantors under the $250,000,000 of 6.30% Senior Notes due February 1, 2009 (filed as Exhibit 4.4 to the Partnership's Form 10-Q (File No. 1-11234) for the quarter ended September 30, 1999 (the "1999 Third Quarter Form 10-Q")).

*4.5 — Indenture dated November 8, 2000 between Kinder Morgan Energy Partners, L.P. and First Union National Bank, as Trustee (filed as Exhibit 4.8 to Kinder Morgan Energy Partners, L.P. Form 10-K for 2001 (File No. 1-11234)).

*4.6 — Form of 7.50% Notes due November 1, 2010 (contained in the Indenture filed as Exhibit 4.8 to the Kinder Morgan Energy Partners, L.P. Form 10-K (File No. 1-11234) for 2001).

*4.7 — Indenture dated January 2, 2001 between Kinder Morgan Energy Partners and First Union National Bank, as trustee, relating to Senior Debt Securities (including form of Senior Debt Securities) (filed as Exhibit 4.11 to Kinder Morgan Energy Partners, L.P. Form 10-K (File No. 1-11234) for 2000).

*4.8 — Indenture dated January 2, 2001 between Kinder Morgan Energy Partners and First Union National Bank, as trustee, relating to Subordinated Debt Securities (including form of Subordinated Debt Securities) (filed as Exhibit 4.12 to Kinder Morgan Energy Partners, L.P. Form 10-K (File No. 1-11234) for 2000).

*4.9 — Certificate of Vice President and Chief Financial Officer of Kinder Morgan Energy Partners, L.P. establishing the terms of the 6.75% Notes due March 15, 2011 and the 7.40% Notes due March 15, 2031 (filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P. Form 8-K (File No. 1-11234), filed on March 14, 2001).

*4.10 — Specimen of 6.75% Notes due March 15, 2011 in book-entry form (filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P. Form 8-K (File No. 1-11234), filed on March 14, 2001).

*4.11 — Specimen of 7.40% Notes due March 15, 2031 in book-entry form (filed as Exhibit 4.3 to Kinder Morgan Energy Partners, L.P. Form 8-K (File No. 1-11234), filed on March 14, 2001).

*4.12 — Certificate of Vice President and Chief Financial Officer of Kinder Morgan Energy Partners, L.P. establishing the terms of the 7.125% Notes due March 15, 2012 and the 7.750% Notes due March 15, 2032 (filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P. Form 10-Q (File No. 1-11234) for the quarter ended March 31, 2002, filed on May 10, 2002).

*4.13 — Specimen of 7.125% Notes due March 15, 2012 in book-entry form (filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P. Form 10-Q (File No. 1-11234) for the quarter ended March 31, 2002, filed on May 10, 2002).

*4.14 — Specimen of 7.750% Notes due March 15, 2032 in book-entry form (filed as Exhibit 4.3 to Kinder Morgan Energy Partners, L.P. Form 10-Q (File No. 1-11234) for the quarter ended March 31, 2002, filed on May 10, 2002).

*4.15 — Indenture dated August 19, 2002 between Kinder Morgan Energy Partners, L.P. and Wachovia Bank, National Association, as Trustee (filed as Exhibit 4.1 to the Kinder Morgan Energy Partners, L.P. Registration Statement on Form S-4 (File No. 333-100346) filed on October 4, 2002 (the "October 4, 2002 Form S-4")).

*4.16 — First Supplemental Indenture to Indenture dated August 19, 2002, dated August 23, 2002 between Kinder Morgan Energy Partners, L.P. and Wachovia Bank, National Association, as Trustee (filed as Exhibit 4.2 to the October 4, 2002 Form S-4).

*4.17 — Form of 7.30% Note (contained in the Indenture filed as Exhibit 4.1 to the October 4, 2002 Form S-4).

*4.18 — Senior Indenture dated January 31, 2003 between Kinder Morgan Energy Partners, L.P. and Wachovia Bank, National Association (filed as Exhibit 4.2 to the Kinder Morgan Energy Partners, L.P. Registration Statement on Form S-3 (File No. 333-102961) filed on February 4, 2003 (the "February 4, 2003 Form S-3")).

*4.19 — Form of Senior Note of Kinder Morgan Energy Partners, L.P. (included in the Form of Senior Indenture filed as Exhibit 4.2 to the February 4, 2003 Form S-3).

*4.20 — Subordinated Indenture dated January 31, 2003 between Kinder Morgan Energy Partners, L.P. and Wachovia Bank, National Association (filed as Exhibit 4.4 to the February 4, 2003 Form S-3).

*4.21 — Form of Subordinated Note of Kinder Morgan Energy Partners, L.P. (included in the Form of Subordinated Indenture filed as Exhibit 4.4 to the February 4, 2003 Form S-3).

*4.22 — Certificate of Vice President, Treasurer and Chief Financial Officer and Vice President, General Counsel and Secretary of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P. establishing the terms of the 5.00% Notes due December 15, 2013 (filed as Exhibit 4.25 to Kinder Morgan Energy Partners, L.P. Form 10-K for 2003 filed March 5, 2004).

*4.23 — Certificate of Executive Vice President and Chief Financial Officer and Vice President, General Counsel and Secretary of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P. establishing the terms of the 5.125% Notes due November 15, 2014 (filed as Exhibit 4.27 to Kinder Morgan Energy Partners, L.P. Form 10-K for 2004 filed March 4, 2005).

*4.24 — Certificate of Vice President, Treasurer and Chief Financial Officer and Vice President, General Counsel and Secretary of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P. establishing the terms of the 5.80% Notes due March 15, 2035 (filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P. Form 10-Q for the quarter ended March 31, 2005, filed on May 6, 2005).

*4.25 — Certificate of Vice President and Chief Financial Officer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P. establishing the terms of the 6.00% Senior Notes due 2017 and 6.50% Senior Notes due 2037 (filed as Exhibit 4.28 to Kinder Morgan Energy Partners, L.P. Form 10-K for 2006 filed March 1, 2007).

*4.26 — Certificate of the Vice President and Treasurer and the Vice President and Chief Financial Officer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 6.95% Senior Notes due 2038 (filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P. Form 10-Q for the quarter ended June 30, 2007 filed August 8, 2007).

*4.27 — Certificate of the Vice President and Treasurer and the Vice President and Chief Financial Officer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 5.85% Senior Notes due 2012 (filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P. Form 10-Q for the quarter ended September 30, 2007 filed November 9, 2007).

4.28 — Certificate of the Vice President and Treasurer and the Vice President and Chief Financial Officer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 5.95% Senior Notes due 2018.

4.29 — Certain instruments with respect to long-term debt of Kinder Morgan Energy Partners, L.P. and its consolidated subsidiaries which relate to debt that does not exceed 10% of the total assets of Kinder Morgan Energy Partners, L.P. and its consolidated subsidiaries are omitted pursuant to Item 601(b) (4) (iii) (A) of Regulation S-K, 17 C.F.R. sec.229.601. Kinder Morgan Energy Partners, L.P. hereby agrees to furnish supplementally to the Securities and Exchange Commission a copy of each such instrument upon request.

*10.1 — Kinder Morgan Energy Partners, L.P. Common Unit Option Plan (filed as Exhibit 10.6 to the Kinder Morgan Energy Partners, L.P. 1997 Form 10-K, File No. 1-11234).

*10.2 — Delegation of Control Agreement among Kinder Morgan Management, LLC, Kinder Morgan G.P., Inc. and Kinder Morgan Energy Partners, L.P. and its operating partnerships (filed as Exhibit 10.1 to the Kinder Morgan Energy Partners, L.P. Form 10-Q for the quarter ended June 30, 2001).

*10.3 — Amendment No. 1 to Delegation of Control Agreement, dated as of July 20, 2007, among Kinder Morgan G.P., Inc., Kinder Morgan Management, LLC, Kinder Morgan Energy Partners, L.P. and its operating partnerships (filed as Exhibit 10.1 to Kinder Morgan Energy Partners, L.P.'s Current Report on Form 8-K on July 20, 2007).

*10.4 — Kinder Morgan Energy Partners, L.P. Directors' Unit Appreciation Rights Plan (filed as Exhibit 10.6 to the Kinder Morgan Energy Partners, L.P. Form 10-K for 2003 filed March 5, 2004).

*10.5 — Amendment No. 1 to Kinder Morgan Energy Partners, L.P. Directors' Unit Appreciation Rights Plan (filed as Exhibit 10.7 to the Kinder Morgan Energy Partners, L.P. Form 10-K for 2003 filed March 5, 2004).

*10.6 — Resignation and Non-Compete agreement dated July 21, 2004 between KMGP Services, Inc. and Michael C. Morgan, President of Kinder Morgan, Inc., Kinder Morgan G.P., Inc. and Kinder Morgan Management, LLC (filed as Exhibit 10.1 to the Kinder Morgan Energy Partners, L.P. Form 10-Q for the quarter ended June 30, 2004, filed on August 5, 2004).

*10.7 — Kinder Morgan Energy Partners, L.P. Common Unit Compensation Plan for Non-Employee Directors (filed as Exhibit 10.2 to Kinder Morgan Energy Partners, L.P. Form 8-K filed January 21, 2005).

*10.8 — Form of Common Unit Compensation Agreement entered into with Non-Employee Directors (filed as Exhibit 10.1 to Kinder Morgan Energy Partners, L.P. Form 8-K filed January 21, 2005).

*10.9 — Five-Year Credit Agreement dated as of August 5, 2005 among Kinder Morgan Energy Partners, L.P., the lenders party thereto and Wachovia Bank, National Association as Administrative Agent (filed as Exhibit 10.1 to Kinder Morgan Energy Partners, L.P.'s Current Report on Form 8-K, filed on August 11, 2005).

*10.10 — First Amendment, dated October 28, 2005, to Five-Year Credit Agreement dated as of August 5, 2005 among Kinder Morgan Energy Partners, L.P., the lenders party thereto and Wachovia Bank, National Association as Administrative Agent (filed as Exhibit 10.1 to Kinder Morgan Energy Partners, L.P.'s Form 10-Q for the quarter ended September 30, 2006).

*10.11 — Second Amendment, dated April 13, 2006, to Five-Year Credit Agreement dated as of August 5, 2005 among Kinder Morgan Energy Partners, L.P., the lenders party thereto and Wachovia Bank, National Association as Administrative Agent (filed as Exhibit 10.2 to Kinder Morgan Energy Partners, L.P.'s Form 10-Q for the quarter ended September 30, 2006).

*10.12 — Third Amendment, dated October 6, 2006, to Five-Year Credit Agreement dated as of August 5, 2005 among Kinder Morgan Energy Partners, L.P., the lenders party thereto and Wachovia Bank, National Association as Administrative Agent (filed as Exhibit 10.3 to Kinder Morgan Energy Partners, L.P.'s Form 10-Q for the quarter ended September 30, 2006).

11.1 — Statement re: computation of per share earnings.

12.1 — Statement re: computation of ratio of earnings to fixed charges.

21.1 — List of Subsidiaries.

23.1 — Consent of PricewaterhouseCoopers LLP.

23.2 — Consent of Netherland, Sewell and Associates, Inc.

31.1 — Certification by CEO pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.2 — Certification by CFO pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32.1 — Certification by CEO pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

32.2 — Certification by CFO pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

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* Asterisk indicates exhibits incorporated by reference as indicated; all other exhibits are filed herewith, except as noted otherwise.

INDEX TO FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

To the Partners of
Kinder Morgan Energy Partners, L.P.:

In our opinion, the accompanying consolidated balance sheets and the related statements of income and comprehensive income, of partners' capital and of cash flows present fairly, in all material respects, the financial position of Kinder Morgan Energy Partners, L.P. (the "Partnership") and its subsidiaries at December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Partnership's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control Over Financial Reporting appearing in item 9A. Our responsibility is to express opinions on these financial statements and on the Partnership's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

As described in Management's Report on Internal Control Over Financial Reporting, management has excluded:

- The Vancouver Wharves bulk marine terminal, acquired May 30, 2007; and
- The terminal assets and operations acquired from Marine Terminals, Inc., effective September 30, 2007,

(the "Acquired Businesses") from its assessment of internal control over financial reporting as of December 31, 2007 because these businesses were each acquired by the Partnership in a purchase business combination during 2007. We have also excluded the Acquired Businesses from our audit of internal control over financial reporting. These Acquired Businesses are wholly-owned subsidiaries whose total assets and total revenues, in the aggregate, represent 0.6% and 1.2%, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2007.

/s/ PricewaterhouseCoopers LLP
PricewaterhouseCoopers LLP
Houston, Texas
February 25, 2008

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31,		
	2007	**2006**	**2005**
	(In millions except per unit amounts)		
Revenues			
Natural gas sales	$ 5,834.7	$ 6,039.9	$ 7,198.5
Services	2,449.2	2,177.6	1,810.5
Product sales and other	933.8	831.2	736.9
	9,217.7	9,048.7	9,745.9
Costs, Expenses and Other			
Gas purchases and other costs of sales	5,809.8	5,990.9	7,167.3
Operations and maintenance	1,024.6	777.0	719.5
Fuel and power	237.5	223.7	178.5
Depreciation, depletion and amortization	540.0	423.9	341.6
General and administrative	278.7	238.4	216.7
Taxes, other than income taxes	153.8	134.4	106.5
Goodwill impairment expense	377.1	—	—
Other expense (income)	(11.5)	(31.2)	—
	8,410.0	7,757.1	8,730.1
Operating Income	807.7	1,291.6	1,015.8
Other Income (Expense)			
Earnings from equity investments	69.7	74.0	89.6
Amortization of excess cost of equity investments	(5.8)	(5.6)	(5.5)
Interest, net	(391.4)	(337.8)	(259.0)
Other, net	14.2	12.0	3.3
Minority Interest	(7.0)	(15.4)	(7.3)
Income from Continuing Operations Before Income Taxes	487.4	1,018.8	836.9
Income Taxes	(71.0)	(29.0)	(24.5)
Income from Continuing Operations	416.4	989.8	812.4
Discontinued Operations:			
Income (loss) from operations of North System	21.1	14.3	(0.2)
Gain on disposal of North System	152.8	—	—
Income (loss) from Discontinued Operations	173.9	14.3	(0.2)
Net Income	$ 590.3	$ 1,004.1	$ 812.2
Calculation of Limited Partners' interest in Net Income (loss):			
Income from Continuing Operations	$ 416.4	$ 989.8	$ 812.4
Less: General Partner's interest	(609.9)	(513.2)	(477.3)
Limited Partners' interest	(193.5)	476.6	335.1
Add: Limited Partners' interest in Discontinued Operations	172.2	14.2	(0.2)
Limited Partners' interest in Net Income (loss)	$ (21.3)	$ 490.8	$ 334.9
Basic Limited Partners' Net Income (loss) per Unit:			
Income (loss) from Continuing Operations	$ (0.82)	$ 2.12	$ 1.58
Income from Discontinued Operations	0.73	0.07	—

Net Income (loss)	$ (0.09)	$ 2.19	$ 1.58
Weighted average number of units outstanding	236.9	224.6	212.2
Diluted Limited Partners' Net Income (loss) per Unit:			
Income (loss) from Continuing Operations	$ (0.82)	$ 2.12	$ 1.58
Income from Discontinued Operations	0.73	0.06	—
Net Income (loss)	$ (0.09)	$ 2.18	$ 1.58
Weighted average number of units outstanding	236.9	224.9	212.4
Per unit cash distribution declared	$ 3.48	$ 3.26	$ 3.13

The accompanying notes are an integral part of these consolidated financial statements.

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended December 31,		
	2007	**2006**	**2005**
		(In millions)	
Net Income	$ 590.3	$ 1,004.1	$ 812.2
Change in fair value of derivatives used for hedging purposes	(974.2)	(187.5)	(1,045.6)
Reclassification of change in fair value of derivatives to net income	433.2	428.1	424.0
Foreign currency translation adjustments	132.5	(19.6)	(0.7)
Minimum pension liability adjustments, pension and other post-retirement benefit plan actuarial gains/losses, and reclassification of pension and other post-retirement benefit plan actuarial gains/losses and prior service costs/credits to net income	(3.5)	(1.8)	—
Total other comprehensive income	(412.0)	219.2	(622.3)
Comprehensive Income	$ 178.3	$ 1,223.3	$ 189.9

The accompanying notes are an integral part of these consolidated financial statements.

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31,	
	2007	2006
	(Dollars in millions)	
ASSETS		
Current Assets		
Cash and cash equivalents	$ 58.9	$ 6.7
Restricted deposits	67.9	—
Accounts, notes and interest receivable, net Trade	960.2	854.7
Related parties	3.6	7.9
Inventories		
Products	19.5	20.4
Materials and supplies	18.3	16.6
Gas imbalances		
Trade	21.2	7.8
Related parties	5.7	11.6
Other current assets	54.4	111.1
	1,209.7	1,036.8
Property, Plant and Equipment, net	11,591.3	10,106.1
Investments	655.4	426.3
Notes receivable		
Trade	0.1	1.2
Related parties	87.9	96.2
Goodwill	1,077.8	1,421.0
Other intangibles, net	238.6	213.2
Deferred charges and other assets	317.0	241.4
Total Assets	$ 15,177.8	$ 13,542.2
LIABILITIES AND PARTNERS' CAPITAL		
Current Liabilities		
Accounts payable		
Cash book overdrafts	$ 19.0	$ 46.2
Trade	926.7	784.1
Related parties	22.6	203.3
Current portion of long-term debt	610.2	1,359.1
Accrued interest	131.2	83.7
Accrued taxes	73.8	35.4
Deferred revenues	22.8	20.0
Gas imbalances		
Trade	23.7	15.9
Related parties	—	—
Accrued other current liabilities	728.3	589.6
	2,558.3	3,137.3
Long-Term Liabilities and Deferred Credits		
Long-term debt		
Outstanding	6,455.9	4,384.3
Value of interest rate swaps	152.2	42.6
	6,608.1	4,426.9
Deferred revenues	14.2	18.8
Deferred income taxes	202.4	185.2
Asset retirement obligations	50.8	48.9
Other long-term liabilities and deferred credits	1,254.1	716.6
	8,129.6	5,396.4

Commitments and Contingencies (Notes 13 and 16)		
Minority Interest	54.2	60.2
Partners' Capital		
Common Units (170,220,396 and 162,816,303 units issued and outstanding as of December 31, 2007 and 2006, respectively)	3,048.4	3,414.9
Class B Units (5,313,400 and 5,313,400 units issued and outstanding as of December 31, 2007 and 2006, respectively)	102.0	126.1
i-Units (72,432,482 and 62,301,676 units issued and outstanding as of December 31, 2007 and 2006, respectively)	2,400.8	2,154.2
General Partner	161.1	119.2
Accumulated other comprehensive loss	(1,276.6)	(866.1)
	4,435.7	4,948.3
Total Liabilities and Partners' Capital	$ 15,177.8	$ 13,542.2

The accompanying notes are an integral part of these consolidated financial statements.

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2007	**2006**	**2005**
		(In millions)	
Cash Flows From Operating Activities			
Net income	$ 590.3	$ 1,004.1	$ 812.2
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	547.0	432.8	349.8
Amortization of excess cost of equity investments	5.8	5.7	5.6
Impairment of goodwill	377.1	—	—
Gains and other non-cash income from the sale of property, plant and equipment	(162.5)	(15.2)	(0.5)
Gains from property casualty indemnifications	(1.8)	(15.2)	—
Earnings from equity investments	(71.5)	(76.2)	(91.7)
Distributions from equity investments	104.1	67.9	63.1
Changes in components of working capital:			
Accounts receivable	92.6	15.8	(240.7)
Other current assets	3.9	13.8	(14.1)
Inventories	(6.9)	0.9	(13.5)
Accounts payable	(79.7)	(48.8)	294.9
Accrued interest	47.3	8.0	17.9
Accrued liabilities	(9.5)	(10.6)	4.5
Accrued taxes	40.7	14.2	(2.3)
Rate reparations, refunds and other litigation reserve adjustments	140.0	(19.1)	105.0
Other, net	124.9	(14.2)	(0.8)
Net Cash Provided by Operating Activities	1,741.8	1,363.9	1,289.4
Cash Flows From Investing Activities			
Acquisitions of assets and equity investments	(713.3)	(387.2)	(307.8)
Additions to property, plant and equip. for expansion and maintenance projects	(1,691.6)	(1,182.1)	(863.1)
Sale of property, plant and equipment, and other net assets net of removal costs	302.6	70.8	9.9
Property casualty indemnifications	8.0	13.1	—
Net proceeds from (Investments in) margin deposits	(70.2)	2.3	—
Contributions to equity investments	(276.1)	(2.5)	(1.2)
Natural gas stored underground and natural gas liquids line-fill	12.3	(12.9)	(18.7)
Other	(0.2)	(3.4)	(0.2)
Net Cash Used in Investing Activities	(2,428.5)	(1,501.9)	(1,181.1)
Cash Flows From Financing Activities			
Issuance of debt	7,686.1	4,632.5	4,900.9
Payment of debt	(6,409.3)	(3,698.7)	(4,463.2)
Repayments from (Loans to) related party	4.4	1.1	2.1
Debt issue costs	(13.8)	(2.0)	(6.0)
Increase (Decrease) in cash book overdrafts	(27.2)	15.8	0.6
Proceeds from issuance of common units	342.9	248.4	415.6
Proceeds from issuance of i-units	297.9	—	—
Contributions from minority interest	8.9	109.8	7.8
Distributions to partners:			
Common units	(552.6)	(512.1)	(460.6)
Class B units	(18.0)	(17.2)	(16.3)
General Partner	(567.7)	(523.2)	(460.9)
Minority interest	(16.0)	(119.0)	(12.1)
Other, net	0.1	(3.0)	(3.9)
Net Cash Provided by (Used in) Financing Activities	735.7	132.4	(96.0)
Effect of exchange rate changes on cash and cash equivalents	3.2	0.2	(0.2)

Increase (Decrease) in Cash and Cash Equivalents	52.2	(5.4)	12.1
Cash and Cash Equivalents, beginning of year	6.7	12.1	—
Cash and Cash Equivalents, end of year	$ 58.9	$ 6.7	$ 12.1

The accompanying notes are an integral part of these consolidated financial statements.

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS (continued)

	Year Ended December 31,		
	2007	2006	2005
		(In millions)	
Noncash Investing and Financing Activities:			
Contribution of net assets to partnership investments	$ —	$ 17.0	$ —
Assets acquired by the issuance of units	15.0	1.6	49.6
Assets acquired by the assumption or incurrence of liabilities	19.7	6.1	76.6
Assets acquired by the transfer of Trans Mountain	—	1,199.5	—
Liabilities assumed by the transfer of Trans Mountain	—	282.5	—
Related party asset settlements with Knight	276.2	—	—
Related party liability settlements with Knight	556.6	—	—
Supplemental disclosures of cash flow information:			
Cash paid during the year for interest (net of capitalized interest)	336.0	329.2	245.6
Cash paid during the year for income taxes	6.2	25.6	7.3

The accompanying notes are an integral part of these consolidated financial statements.

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL

	2007		2006		2005	
	Units	Amount	Units	Amount	Units	Amount
			(Dollars in millions)			
Common Units:						
Beginning Balance	162,816,303	$ 3,414.9	157,005,326	$ 2,680.4	147,537,908	$ 2,438.0
Net income (loss)	—	(20.4)	—	347.8	—	237.8
Units issued as consideration pursuant to common unit compensation plan for non-employee directors	7,280	0.4	5,250	0.3	5,250	0.3
Units issued as consideration in the acquisition of assets	266,813	15.0	34,627	1.6	1,022,068	49.6
Units issued for cash	7,130,000	342.5	5,771,100	248.2	8,440,100	415.3
Trans Mountain Acquisition	—	(166.8)	—	648.7	—	—
Knight Inc. going-private transaction exp.	—	15.4	—	—	—	—
Distributions	—	(552.6)	—	(512.1)	—	(460.6)
Ending Balance	170,220,396	3,048.4	162,816,303	3,414.9	157,005,326	2,680.4
Class B Units:						
Beginning Balance	5,313,400	126.1	5,313,400	109.6	5,313,400	117.4
Net income (loss)	—	(0.6)	—	11.6	—	8.5
Trans Mountain Acquisition	—	(6.0)	—	22.1	—	—
Knight Inc. going-private transaction exp.	—	0.5	—	—	—	—
Distributions	—	(18.0)	—	(17.2)	—	(16.3)
Ending Balance	5,313,400	102.0	5,313,400	126.1	5,313,400	109.6
i-Units:						
Beginning Balance	62,301,676	2,154.2	57,918,373	1,783.6	54,157,641	1,695.0
Net income (loss)	—	(0.3)	—	131.4	—	88.7
Units issued for cash	5,700,000	297.6	—	—	—	(0.1)
Trans Mountain Acquisition	—	(57.4)	—	239.2	—	—
Knight Inc. going-private transaction exp.	—	6.7	—	—	—	—
Distributions	4,430,806	—	4,383,303	—	3,760,732	—
Ending Balance	72,432,482	2,400.8	62,301,676	2,154.2	57,918,373	1,783.6
General Partner:						
Beginning Balance	—	119.2	—	119.9	—	103.5
Net income	—	611.6	—	513.3	—	477.3
Trans Mountain Acquisition	—	(2.2)	—	9.2	—	—
Knight Inc. going-private transaction exp.	—	0.2	—	—	—	—
Distributions	—	(567.7)	—	(523.2)	—	(460.9)
Ending Balance	—	161.1	—	119.2	—	119.9
Accum. other comprehensive income (loss):						
Beginning Balance	—	(866.1)	—	(1,079.7)	—	(457.4)
Change in fair value of derivatives used for hedging purposes	—	(974.2)	—	(187.5)	—	(1,045.6)
Reclassification of change in fair value of derivatives to net income	—	433.2	—	428.1	—	424.0
Foreign currency translation adjustments	—	132.5	—	(19.6)	—	(0.7)
Pension and other post-retirement benefit liability changes	—	(3.5)	—	(1.8)	—	—

Adj. to initially apply SFAS No. 158-pension and other post-retirement benefit acctg. changes	—	1.5	—	(5.6)	—	—
Ending Balance	—	(1,276.6)	—	(866.1)	—	(1,079.7)
Total Partners' Capital	247,966,278	$ 4,435.7	230,431,379	$ 4,948.3	220,237,099	$ 3,613.8

The accompanying notes are an integral part of these consolidated financial statements.

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization

General

Kinder Morgan Energy Partners, L.P. is a Delaware limited partnership formed in August 1992. Unless the context requires otherwise, references to "we," "us," "our" or the "Partnership" are intended to mean Kinder Morgan Energy Partners, L.P. and its consolidated subsidiaries.

We own and manage a diversified portfolio of energy transportation and storage assets and presently conduct our business through five reportable business segments. These segments and the activities performed to provide services to our customers and create value for our unitholders are as follows:

- Products Pipelines - transporting, storing and processing refined petroleum products;
- Natural Gas Pipelines - transporting, storing, selling, gathering, treating and processing natural gas;
- CO_2 - producing, transporting and selling carbon dioxide, commonly called CO_2, for use in, and selling crude oil, natural gas and natural gas liquids produced from, enhanced oil recovery operations;
- Terminals - transloading, storing and delivering a wide variety of bulk, petroleum, petrochemical and other liquid products at terminal facilities located across North America; and
- Trans Mountain – transporting crude oil and refined petroleum products from Edmonton, Alberta, Canada to marketing terminals and refineries in British Columbia and the state of Washington.

We focus on providing fee-based services to customers, generally avoiding near-term commodity price risks and taking advantage of the tax benefits of a limited partnership structure. We trade on the New York Stock Exchange under the symbol "KMP," and we conduct our operations through the following five limited partnerships:

- Kinder Morgan Operating L.P. "A" (OLP-A);
- Kinder Morgan Operating L.P. "B" (OLP-B);
- Kinder Morgan Operating L.P. "C" (OLP-C);
- Kinder Morgan Operating L.P. "D" (OLP-D); and
- Kinder Morgan CO_2 Company (KMCO2).

Combined, the five limited partnerships are referred to as our operating partnerships, and we are the 98.9899% limited partner and our general partner is the 1.0101% general partner in each. Both we and our operating partnerships are governed by Amended and Restated Agreements of Limited Partnership, as amended and certain other agreements that are collectively referred to in this report as the partnership agreements.

Knight Inc. and Kinder Morgan G.P., Inc.

On August 28, 2006, Kinder Morgan, Inc., a Kansas corporation referred to as "KMI" in this report, entered into an agreement and plan of merger whereby generally each share of KMI common stock would be converted into the right to receive $107.50 in cash without interest. KMI in turn would merge with a wholly owned subsidiary of Knight Holdco LLC, a privately owned company in which Richard D. Kinder, Chairman and Chief Executive Officer of KMI, would be a major investor. On May 30, 2007, the merger closed, with KMI continuing as the surviving legal entity and subsequently renamed "Knight Inc.," referred to as "Knight" in this report. Additional investors in Knight Holdco LLC include the following: other senior members of Knight management, most of whom are also senior officers of Kinder Morgan G.P., Inc. (our general partner) and of Kinder Morgan Management, LLC (our general partner’s delegate); KMI co-founder William V. Morgan; KMI board members Fayez Sarofim and Michael C. Morgan; and affiliates of (i) Goldman Sachs Capital Partners; (ii) American International Group, Inc.; (iii) The Carlyle Group; and (iv) Riverstone Holdings LLC. This transaction is referred to in this report as the "going-private transaction."

Knight is privately owned, and remains the sole indirect common stockholder of our general partner. On July 27, 2007, our general partner issued and sold 100,000 shares of Series A fixed-to-floating rate term cumulative preferred stock due 2057. The consent of holders of a majority of these preferred shares is required with respect to a commencement of or a filing of a voluntary bankruptcy proceeding with respect to us, or two of our subsidiaries: SFPP, L.P. and Calnev Pipe Line LLC. At December 31, 2007, Knight and its consolidated subsidiaries owned, through its general and limited partner interests, an approximate 13.9% interest in us.

Kinder Morgan Management, LLC

Kinder Morgan Management, LLC, a Delaware limited liability company, was formed on February 14, 2001. Its shares represent limited liability company interests and are traded on the New York Stock Exchange under the symbol "KMR." Kinder Morgan Management, LLC is referred to as "KMR" in this report. Our general partner owns all of KMR’s voting securities and, pursuant to a delegation of control agreement, our general partner delegated to KMR, to the fullest extent permitted under Delaware law and our partnership agreement, all of its power and authority to manage and control our business and affairs, except that KMR cannot take certain specified actions without the approval of our general partner.

Under the delegation of control agreement, KMR manages and controls our business and affairs and the business and affairs of our operating limited partnerships and their subsidiaries. Furthermore, in accordance with its limited liability company agreement, KMR’s activities are limited to being a limited partner in, and managing and controlling the business and affairs of us, our operating limited partnerships and their subsidiaries. As of December 31, 2007, KMR owned approximately 29.2% of our outstanding limited partner units (which are in the form of i-units that are issued only to KMR).

2. Summary of Significant Accounting Policies

Basis of Presentation

Our consolidated financial statements include our accounts and those of our operating partnerships and their majority-owned and controlled subsidiaries. Our accounting records are maintained in United States dollars, and all references to dollars are United States dollars, except where stated otherwise. Canadian dollars are designated as C$. All significant intercompany items have been eliminated in consolidation. Certain amounts from prior years have been reclassified to conform to the current presentation.

Our consolidated financial statements were prepared in accordance with accounting principles generally accepted in the United States. We believe, however, that certain accounting policies are of more significance in our financial statement preparation process than others. Also, certain amounts included in or affecting our financial statements and related disclosures must be estimated, requiring us to make certain assumptions with respect to values or conditions which cannot be known with certainty at the time our financial statements are prepared.

These estimates and assumptions affect the amounts we report for assets and liabilities, our revenues and expenses during the reporting period, and our disclosure of contingent assets and liabilities at the date of our financial statements. We evaluate these estimates on an ongoing basis, utilizing historical experience, consultation with experts and other methods we consider reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from our estimates. Any effects on our business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known.

Cash Equivalents

We define cash equivalents as all highly liquid short-term investments with original maturities of three months or less.

Accounts Receivables

Our policy for determining an appropriate allowance for doubtful accounts varies according to the type of business being conducted and the customers being served. An allowance for doubtful accounts is charged to expense monthly, generally using a percentage of revenue or receivables, based on a historical analysis of uncollected amounts, adjusted as necessary for changed circumstances and customer-specific information. When specific receivables are determined to be uncollectible, the reserve and receivable are relieved. The following table shows the balance in the allowance for doubtful accounts and activity for the years ended December 31, 2007, 2006 and 2005 (in millions):

Valuation and Qualifying Accounts

Allowance for Doubtful Accounts	Balance at beginning of Period	Additions charged to costs and expenses	Additions charged to other accounts(1)	Deductions(2)	Balance at end of period
Year ended December 31, 2007	$ 6.8	$ 0.4	$ —	$ (0.2)	$ 7.0
Year ended December 31, 2006	$ 6.5	$ 0.3	$ 0.3	$ (0.3)	$ 6.8
Year ended December 31, 2005	$ 8.6	$ 0.2	$ —	$ (2.3)	$ 6.5

(1) Amount for 2006 represents the allowance recognized when we acquired Devco USA L.L.C. ($0.2) and Transload Services, LLC ($0.1).

(2) Deductions represent the write-off of receivables.

In addition, the balances of "Accrued other current liabilities" in our accompanying consolidated balance sheets include amounts related to customer prepayments of approximately $6.5 million as of December 31, 2007 and $10.8 million as of December 31, 2006.

Inventories

Our inventories of products consist of natural gas liquids, refined petroleum products, natural gas, carbon dioxide and coal. We report these assets at the lower of weighted-average cost or market. We report materials and supplies at the lower of cost or market. As of December 31, 2007, we owed certain customers a total of $8.3 million for the value of natural gas inventory stored in our underground storage facilities, and we reported this amount within "Accounts Payable—Trade" in our accompanying consolidated balance sheet. As of December 31, 2006, the value of natural gas in our underground storage facilities under the weighted-average cost method was $8.4 million, and we reported this amount within "Other current assets" in our accompanying consolidated balance sheet. We also maintain gas in our underground storage facilities on behalf of certain third parties. We receive a fee from our storage service customers but do not reflect the value of their gas stored in our facilities in our accompanying consolidated balance sheets.

Property, Plant and Equipment

Capitalization, Depreciation and Depletion and Disposals

We report property, plant and equipment at its acquisition cost. We expense costs for maintenance and repairs in the period incurred. The cost of property, plant and equipment sold or retired and the related depreciation are removed from our balance sheet in the period of sale or disposition. For our pipeline system assets, we generally charge the original cost of property sold or retired to accumulated depreciation and amortization, net of salvage and cost of removal. We do not include retirement gain or loss in income except in the case of significant retirements or sales. Gains and losses on minor system sales, excluding land, are recorded to the appropriate accumulated depreciation reserve. Gains and losses for operating systems sales and land sales are booked to income or expense accounts in accordance with regulatory accounting guidelines.

We compute depreciation using the straight-line method based on estimated economic lives. Generally, we apply composite depreciation rates to functional groups of property having similar economic characteristics. The rates range from 2.0% to 12.5%, excluding certain short-lived assets such as vehicles. Depreciation estimates are based on various factors, including age (in the case of acquired assets), manufacturing specifications, technological advances and historical data concerning useful lives of similar assets. Uncertainties that impact these estimates included changes in laws and regulations relating to restoration and abandonment requirements, economic conditions, and supply and demand in the area. When assets are put into service, we make estimates with respect to useful lives (and salvage values where appropriate) that we believe are reasonable. However, subsequent events could cause us to change our estimates, thus impacting the future calculation of depreciation and amortization expense. Historically, adjustments to useful lives have not had a material impact on our aggregate depreciation levels from year to year.

Our oil and gas producing activities are accounted for under the successful efforts method of accounting. Under this method costs that are incurred to acquire leasehold and subsequent development costs are capitalized. Costs that are associated with the drilling of successful exploration wells are capitalized if proved reserves are found. Costs associated with the drilling of exploratory wells that do not find proved reserves, geological and geophysical costs, and costs of certain non-producing leasehold costs are expensed as incurred. The capitalized costs of our producing oil and gas properties are depreciated and depleted by the units-of-production method. Other miscellaneous property, plant and equipment are depreciated over the estimated useful lives of the asset.

A gain on the sale of property, plant and equipment used in our oil and gas producing activities or in our bulk and liquids terminal activities is calculated as the difference between the cost of the asset disposed of, net of depreciation, and the sales proceeds received. A gain on an asset disposal is recognized in income in the period that the sale is closed. A loss on the sale of property, plant and equipment is calculated as the difference between the cost of the asset disposed of, net of depreciation, and the sales proceeds received or the maket value if the asset is being held for sale. A loss is recognized when the asset is sold or when the net cost of an asset held for sale is greater than the market value of the asset.

In addition, we engage in enhanced recovery techniques in which carbon dioxide is injected into certain producing oil reservoirs. In some cases, the acquisition cost of the carbon dioxide associated with enhanced recovery is capitalized as part of our development costs when it is injected. The acquisition cost associated with pressure maintenance operations for reservoir management is expensed when it is injected. When carbon dioxide is recovered in conjunction with oil production, it is extracted and re-injected, and all of the associated costs are expensed as incurred. Proved developed reserves are used in computing units of production rates for drilling and development costs, and total proved reserves are used for depletion of leasehold costs. The units-of-production rate is determined by field.

As discussed in "—Inventories" above, we maintain natural gas in underground storage as part of our inventory. This component of our inventory represents the portion of gas stored in an underground storage facility generally known as "working gas," and represents an estimate of the portion of gas in these facilities available for routine injection and withdrawal to meet demand. In addition to this working gas, underground gas storage reservoirs contain injected gas which is not routinely cycled but, instead, serves the function of maintaining the necessary pressure to allow efficient operation of the facility. This gas, generally known as "cushion gas," is divided into the categories of "recoverable cushion gas" and "unrecoverable cushion gas," based on an engineering analysis of whether the gas can be economically removed from the storage facility at any point during its life. The portion of the cushion gas that is determined to be unrecoverable is considered to be a permanent part of the facility itself (thus, part of our "Property, Plant and Equipment, net" balance in our accompanying consolidated balance sheets), and this unrecoverable portion is depreciated over the facility’s estimated useful life. The portion of the cushion gas that is determined to be recoverable is also considered a component of the facility but is not depreciated because it is expected to ultimately be recovered and sold.

Impairments

We evaluate the impairment of our long-lived assets in accordance with Statement of Financial Accounting Standards No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." SFAS No. 144 requires that long-lived assets that are to be disposed of by sale be measured at the lower of book value or fair value less the cost to sell. We review for the impairment of long-lived assets whenever events or changes in circumstances indicate that our carrying amount of an asset may not be recoverable. We would recognize an impairment loss when estimated future cash flows expected to result from our use of the asset and its eventual disposition is less than its carrying amount.

We evaluate our oil and gas producing properties for impairment of value on a field-by-field basis or, in certain instances, by logical grouping of assets if there is significant shared infrastructure, using undiscounted future cash flows based on total proved and risk-adjusted probable and possible reserves. Oil and gas producing properties deemed to be impaired are written down to their fair value, as determined by discounted future cash flows based on total proved and risk-adjusted probable and possible reserves or, if available, comparable market values. Unproved oil and gas properties that are individually significant are periodically assessed for impairment of value, and a loss is recognized at the time of impairment.

Equity Method of Accounting

We account for investments greater than 20% in affiliates, which we do not control, by the equity method of accounting. Under this method, an investment is carried at our acquisition cost, plus our equity in undistributed earnings or losses since acquisition, and less distributions received.

Excess of Cost Over Fair Value

We account for our business acquisitions and intangible assets in accordance with the provisions of SFAS No. 141, "Business Combinations," and SFAS No. 142, "Goodwill and Other Intangible Assets." Accounting standards require that goodwill not be amortized, but instead should be tested, at least on an annual basis, for impairment. Pursuant to this SFAS No. 142, goodwill and other intangible assets with indefinite useful lives cannot be amortized until their useful life becomes determinable. Instead, such assets must be tested for impairment annually or on an interim basis if events or circumstances indicate that the fair value of the asset has decreased below its carrying value. We have selected an impairment measurement test date of January 1 of each year and we have determined that our goodwill was not impaired as of January 1, 2008; however, our consolidated income statement for the year ended December 31, 2007 included a goodwill impairment expense of $377.1 million, due to the inclusion of Knight's first quarter 2007 impairment of goodwill that resulted from a determination of the fair values of Trans Mountain pipeline assets prior to our acquisition of these assets on April 30, 2007. For more information on this acquisition and this impairment expense, see Notes 3 and 8, respectively.

Our total unamortized excess cost over fair value of net assets in consolidated affiliates was $1,077.8 million as of December 31, 2007 and $1,421.0 million as of December 31, 2006. Such amounts are reported as "Goodwill" on our accompanying consolidated balance sheets. Our total unamortized excess cost over underlying fair value of net assets accounted for under the equity method was$138.2 million as of both December 31, 2007 and December 31, 2006. Pursuant to SFAS No. 142, this amount, referred to as equity method goodwill, should continue to be recognized in accordance with Accounting Principles Board Opinion No. 18, "The Equity Method of Accounting for Investments in Common Stock." Accordingly, we included this amount within "Investments" on our accompanying consolidated balance sheets.

In almost all cases, the price we paid to acquire our share of the net assets of our equity investees differed from the underlying book value of such net assets. This differential consists of two pieces. First, an amount related to the difference between the investee's recognized net assets at book value and at current fair values (representing the appreciated value in plant and other net assets), and secondly, to any premium in excess of fair value (representing equity method goodwill as described above) we paid to acquire the investment. The first differential, representing the excess of the fair market value of our investees' plant and other net assets over its underlying book value at the date of acquisition totaled $174.7 million and $177.1 million as of December 31, 2007 and 2006, respectively, and similar to our treatment of equity method goodwill, we included these amounts within "Investments" on our accompanying consolidated balance sheets. As of December 31, 2007, this excess investment cost is being amortized over a weighted average life of approximately 30.9 years.

In addition to our annual impairment test of goodwill, we periodically reevaluate the amount at which we carry the excess of cost over fair value of net assets accounted for under the equity method, as well as the amortization period for such assets, to determine whether current events or circumstances warrant adjustments to our carrying value and/or revised estimates of useful lives in accordance with APB Opinion No. 18. The impairment test under APB No. 18 considers whether the fair value of the equity investment as a whole, not the underlying net assets, has declined and whether that decline is other than temporary. As of December 31, 2007, we believed no such impairment had occurred and no reduction in estimated useful lives was warranted. For more information on our investments, see Note 7.

Revenue Recognition Policies

We recognize revenues as services are rendered or goods are delivered and, if applicable, title has passed. We generally sell natural gas under long-term agreements, with periodic price adjustments. In some cases, we sell natural gas under short-term agreements at prevailing market prices. In all cases, we recognize natural gas sales revenues when the natural gas is sold to a purchaser at a fixed or determinable price, delivery has occurred and title has transferred, and collectibility of the revenue is reasonably assured. The natural gas we market is primarily purchased gas produced by third parties, and we market this gas to power generators, local distribution companies, industrial end-users and national marketing companies. We recognize gas gathering and marketing revenues in the month of delivery based on customer nominations and generally, our natural gas marketing revenues are recorded gross, not net of cost of gas sold.

We provide various types of natural gas storage and transportation services to customers. The natural gas remains the property of these customers at all times. In many cases (generally described as "firm service"), the customer pays a two-part rate that includes (i) a fixed fee reserving the right to transport or store natural gas in our facilities and (ii) a per-unit rate for volumes actually transported or injected into/withdrawn from storage. The fixed-fee component of the overall rate is recognized as revenue in the period the service is provided. The per-unit charge is recognized as revenue when the volumes are delivered to the customers' agreed upon delivery point, or when the volumes are injected into/withdrawn from our storage facilities. In other cases (generally described as "interruptible service"), there is no fixed fee associated with the services because the customer accepts the possibility that service may be interrupted at our discretion in order to serve customers who have purchased firm service. In the case of interruptible service, revenue is recognized in the same manner utilized for the per-unit rate for volumes actually transported under firm service agreements. In addition to our "firm" and "interruptible" transportation services, we also provide natural gas park and loan service to assist customers in managing short-term gas surpluses or deficits. Revenues are recognized based on the terms negotiated under these contracts.

We provide crude oil transportation services and refined petroleum products transportation and storage services to customers. Revenues are recorded when products are delivered and services have been provided, and adjusted according to terms prescribed by the toll settlements with shippers and approved by regulatory authorities.

We recognize bulk terminal transfer service revenues based on volumes loaded and unloaded. We recognize liquids terminal tank rental revenue ratably over the contract period. We recognize liquids terminal throughput revenue based on volumes received and volumes delivered. Liquids terminal minimum take-or-pay revenue is recognized at the end of the contract year or contract term depending on the terms of the contract. We recognize transmix processing revenues based on volumes processed or sold, and if applicable, when title has passed. We recognize energy-related product sales revenues based on delivered quantities of product.

Revenues from the sale of oil, natural gas liquids and natural gas production are recorded using the entitlement method. Under the entitlement method, revenue is recorded when title passes based on our net interest. We record our entitled share of revenues based on entitled volumes and contracted sales prices. Since there is a ready market for oil and gas production, we sell the majority of our products soon after production at various locations, at which time title and risk of loss pass to the buyer. As a result, we maintain a minimum amount of product inventory in storage.

Allowance For Funds Used During Construction

Included in the cost of our qualifying property, plant and equipment is an allowance for funds used during construction or upgrade, often referred to as AFUDC. AFUDC represents the estimated cost of capital, from borrowed funds, during the construction period. Total AFUDC resulting from the capitalization of interest expense in 2007, 2006 and 2005 was $31.4 million, $20.3 million and $9.8 million, respectively. Approximately $6.1 million and $2.2 million of AFUDC on equity, related to our Trans Mountain pipeline system assets, was also capitalized in the twelve months ended December 31, 2007 and 2006, respectively.

Unit-Based Compensation

We account for common unit options granted under our common unit option plan according to the provisions of SFAS No. 123R (revised 2004), "Share-Based Payment," which became effective for us January 1, 2006. However, we have not granted common unit options or made any other share-based payment awards since May 2000, and as of December 31, 2005, all outstanding options to purchase our common units were fully vested. Therefore, the adoption of this Statement did not have an effect on the accounting for these common unit options in our consolidated financial statements, as we had reached the end of the requisite service period for any compensation cost resulting from share-based payments made under our common unit option plan.

Environmental Matters

We expense or capitalize, as appropriate, environmental expenditures that relate to current operations. We expense expenditures that relate to an existing condition caused by past operations, which do not contribute to current or future revenue generation. We do not discount environmental liabilities to a net present value, and we record environmental liabilities when environmental assessments and/or remedial efforts are probable and we can reasonably estimate the costs. Generally, our recording of these accruals coincides with our completion of a feasibility study or our commitment to a formal plan of action. We recognize receivables for anticipated associated insurance recoveries when such recoveries are deemed to be probable.

We routinely conduct reviews of potential environmental issues and claims that could impact our assets or operations. These reviews assist us in identifying environmental issues and estimating the costs and timing of remediation efforts. We also routinely adjust our environmental liabilities to reflect changes in previous estimates. In making environmental liability estimations, we consider the material effect of environmental compliance, pending legal actions against us, and potential third-party liability claims. Often, as the remediation evaluation and effort progresses, additional information is obtained, requiring revisions to estimated costs. These revisions are reflected in our income in the period in which they are reasonably determinable. For more information on our environmental disclosures, see Note 16.

Legal

We are subject to litigation and regulatory proceedings as the result of our business operations and transactions. We utilize both internal and external counsel in evaluating our potential exposure to adverse outcomes from orders, judgments or settlements. When we identify specific litigation that is expected to continue for a significant period of time and require substantial expenditures, we identify a range of possible costs expected to be required to litigate the matter to a conclusion or reach an acceptable settlement, and we accrue for such amounts. To the extent that actual outcomes differ from our estimates, or additional facts and circumstances cause us to revise our estimates, our earnings will be affected. In general, we expense legal costs as incurred and all recorded legal liabilities are revised as better information becomes available. For more information on our legal disclosures, see Note 16.

Pensions and Other Post-retirement Benefits

We account for pension and other post-retirement benefit plans according to the provisions of SFAS No. 158, "Employers’ Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statement Nos. 87, 88, 106 and 132(R)." This Statement requires us to fully recognize the overfunded or underfunded status of our consolidating subsidiaries’ pension and post-retirement benefit plans as either assets or liabilities on our balance sheet. For more information on our pension and post-retirement benefit disclosures, see Note 10.

Gas Imbalances

We value gas imbalances due to or due from interconnecting pipelines at the lower of cost or market. Gas imbalances represent the difference between customer nominations and actual gas receipts from, and gas deliveries to, our interconnecting pipelines and shippers under various operational balancing and shipper imbalance agreements. Natural gas imbalances are either settled in cash or made up in-kind subject to the pipelines' various tariff provisions.

Minority Interest

Minority interest, sometimes referred to as noncontrolling interest, represents the outstanding ownership interests in our five operating limited partnerships and their consolidated subsidiaries that are not owned by us. In our consolidated income statements, the minority interest in the income (or loss) of a consolidated subsidiary is shown as a deduction from (or an addition to) our consolidated net income. In our consolidated balance sheets, minority interest represents the noncontrolling ownership interest in our consolidated net assets and is presented separately between liabilities and Partners' Capital.

As of December 31, 2007, minority interest consisted of the following:

- the 1.0101% general partner interest in each of our five operating partnerships;
- the 0.5% special limited partner interest in SFPP, L.P.;
- the 50% interest in Globalplex Partners, a Louisiana joint venture owned 50% and controlled by Kinder Morgan Bulk Terminals, Inc.;
- the 33 1/3% interest in International Marine Terminals Partnership, a Louisiana partnership owned 66 2/3% and controlled by Kinder Morgan Operating L.P. "C";
- the approximate 31% interest in the Pecos Carbon Dioxide Company, a Texas general partnership owned approximately 69% and controlled by Kinder Morgan CO_2 Company, L.P. and its consolidated subsidiaries;
- the 1% interest in River Terminals Properties, L.P., a Tennessee partnership owned 99% and controlled by Kinder Morgan River Terminals LLC; and
- the 30% interest in Guilford County Terminal Company, LLC, a limited liability company owned 70% and controlled by Kinder Morgan Southeast Terminals LLC.

Income Taxes

We are not a taxable entity for federal income tax purposes. As such, we do not directly pay federal income tax. Our taxable income or loss, which may vary substantially from the net income or net loss we report in our consolidated statement of income, is includable in the federal income tax returns of each partner. The aggregate difference in the basis of our net assets for financial and tax reporting purposes cannot be readily determined as we do not have access to information about each partner's tax attributes in us.

Some of our corporate subsidiaries and corporations in which we have an equity investment do pay U.S. federal, state, and foreign income taxes. Deferred income tax assets and liabilities for certain operations conducted through corporations are recognized for temporary differences between the assets and liabilities for financial reporting and tax purposes. Changes in tax legislation are included in the relevant computations in the period in which such changes are effective. Deferred tax assets are reduced by a valuation allowance for the amount of any tax benefit not expected to be realized.

Foreign Currency Transactions and Translation

We account for foreign currency transactions and the foreign currency translation of our consolidating foreign subsidiaries in accordance with the provisions of SFAS No. 52, "Foreign Currency Translation." Foreign currency transactions are those transactions whose terms are denominated in a currency other than the currency of the primary economic environment in which our foreign subsidiary operates, also referred to as its functional currency. Transaction gains or losses result from a change in exchange rates between (i) the functional currency, for example the Canadian dollar for a Canadian subsidiary; and (ii) the currency in which a foreign currency transaction is denominated, for example the U.S. dollar for a Canadian subsidiary.

We translate the assets and liabilities of each of our consolidating foreign subsidiaries to U.S. dollars at year-end exchange rates. Income and expense items are translated at weighted-average rates of exchange prevailing during the year and stockholders' equity accounts are translated by using historical exchange rates. Translation adjustments result from translating all assets and liabilities at current year-end rates, while stockholders' equity is translated by using historical and weighted-average rates. The cumulative translation adjustments balance is reported as a component of accumulated other comprehensive income/(loss) within Partners' Capital on our accompanying consolidated balance sheet.

Comprehensive Income

Statement of Financial Accounting Standards No. 130, "Accounting for Comprehensive Income," requires that enterprises report a total for comprehensive income. The difference between our net income and our comprehensive income resulted from (i) unrealized gains or losses on derivatives utilized for hedging our exposure to fluctuating expected future cash flows produced by price or interest rate risk; (ii) foreign currency translation adjustments; and (iii) unrealized periodic benefit costs from minimum pension liability adjustments and the reclassification of post-retirement benefit and pension plan actuarial gains/losses and prior service costs/credits to net income. For more information on our risk management activities, see Note 14.

Cumulative revenues, expenses, gains and losses that under generally accepted accounting principals are included within our comprehensive income but excluded from our earnings are reported as accumulated other comprehensive income/(loss) within Partners' Capital in our consolidated balance sheets. The following table summarizes changes in the amount of our "Accumulated other comprehensive loss" in our accompanying consolidated balance sheets for each of the two years ended December 31, 2006 and 2007 (in millions):

	Net unrealized gains/(losses) on cash flow hedge derivatives	Foreign currency translation adjustments	Pension and Other Post-retirement liability adjs.	Total Accumulated other comprehensive income/(loss)
December 31, 2005	$ (1,079.3)	$ (0.4)	$ —	$ (1,079.7)
Change for period	240.6	(19.6)	(7.4)	213.6
December 31, 2006	(838.7)	(20.0)	(7.4)	(866.1)
Change for period	(541.0)	132.5	(2.0)	(410.5)
December 31, 2007	$ (1,379.7)	$ 112.5	$ (9.4)	$ (1,276.6)

Net Income Per Unit

We compute Basic Limited Partners' Net Income per Unit by dividing our limited partners' interest in net income by the weighted average number of units outstanding during the period. Diluted Limited Partners' Net Income per Unit reflects the maximum potential dilution that could occur if units whose issuance depends on the market price of the units at a future date were considered outstanding, or if, by application of the treasury stock method, options to issue units were exercised, both of which would result in the issuance of additional units that would then share in our net income.

Emerging Issues Task Force Issue No. 03-6, or EITF 03-6, "Participating Securities and the Two-Class Method Under FASB Statement No 128" addresses the computation of earnings per share by entities that have issued securities other than common stock that contractually entitle the holder to participate in dividends and earnings of the entity when, and if, it declares dividends on its securities. For partnerships, under the two-class method, earnings per unit is calculated as if all of the earnings for the period were distributed regardless of whether a general partner has discretion over the amount of distribution to be made for any particular period. EITF 03-6 does not impact our overall net income or other financial results because we do not have undistributed earnings in any period presented in this report.

Asset Retirement Obligations

We account for asset retirement obligations pursuant to SFAS No. 143, "Accounting for Asset Retirement Obligations." For more information on our asset retirement obligations, see Note 4.

Risk Management Activities

We utilize energy commodity derivative contracts for the purpose of mitigating our risk resulting from fluctuations in the market price of natural gas, natural gas liquids and crude oil. In addition, we enter into interest rate swap agreements for the purpose of hedging the interest rate risk associated with our debt obligations.

Our derivative contracts are accounted for under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS No. 137, "Accounting for Derivative Instruments and Hedging Activities – Deferral of the Effective Date of FASB Statement No.133" and No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities."SFAS No. 133 established accounting and reporting standards requiring that every derivative contract (including certain derivative contracts embedded in other contracts) be recorded in the balance sheet as either an asset or liability measured at its fair value. SFAS No. 133 requires that changes in the derivative contract's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. If a derivative contract meets those criteria, SFAS No. 133 allows a derivative contract's gains and losses to offset related results on the hedged item in the income statement, and requires that a company formally designate a derivative contract as a hedge and document and assess the effectiveness of derivative contracts associated with transactions that receive hedge accounting.

Furthermore, if the derivative transaction qualifies for and is designated as a normal purchase and sale, it is exempted from the fair value accounting requirements of SFAS No. 133 and is accounted for using traditional accrual accounting. Our derivative contracts that hedge our commodity price risks involve our normal business activities, which include the sale of natural gas, natural gas liquids and crude oil, and these derivative contracts have been designated as cash flow hedges as defined by SFAS No. 133. SFAS No. 133 designates derivative contracts that hedge exposure to variable cash flows of forecasted transactions as cash flow hedges and the effective portion of the derivative contract's gain or loss is initially reported as a component of other comprehensive income (outside earnings) and subsequently reclassified into earnings when the forecasted transaction affects earnings. The ineffective portion of the gain or loss is reported in earnings immediately. See Note 14 for more information on our risk management activities.

Accounting for Regulatory Activities

Our regulated utility operations are accounted for in accordance with the provisions of SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation," which prescribes the circumstances in which the application of generally accepted accounting principles is affected by the economic effects of regulation. Regulatory assets and liabilities represent probable future revenues or expenses associated with certain charges and credits that will be recovered from or refunded to customers through the ratemaking process.

The following regulatory assets and liabilities are reflected within "Deferred charges and other assets" and "Other long-term liabilities and deferred credits," respectively, in our accompanying consolidated balance sheets as of December 31, 2007 and December 31, 2006 (in millions):

	As of December 31, 2007	As of December 31, 2006
Regulated Assets:		
Employee benefit costs	$ 0.6	$ 0.4
Fuel Tracker	2.4	1.6
Deferred regulatory expenses	3.4	3.2
Total regulatory assets	6.4	5.2
Regulated Liabilities:		
Deferred income taxes	—	0.9
Total regulatory liabilities	—	0.9
Net regulatory assets	$ 6.4	$ 4.3

As of December 31, 2007, all of our regulatory assets and regulatory liabilities were being recovered from or refunded to customers through rates over periods ranging from one to five years.

3. Acquisitions, Joint Ventures and Divestitures

Acquisitions and Joint Ventures Involving Unrelated Entities

During 2007, 2006 and 2005, we completed the following acquisitions, and except for our acquisition of the Trans Mountain pipeline system (discussed below), these acquisitions were accounted for as business combinations according to the provisions of Statement of Financial Accounting Standards No. 141, "Business Combinations." SFAS No. 141 requires business combinations involving unrelated entities to be accounted for using the purchase method of accounting, which establishes a new basis of accounting for the purchased assets and liabilities—the acquirer records all the acquired assets and assumed liabilities at their estimated fair market values (not the acquired entity's book values) as of the acquisition date.

The preliminary allocation of these assets (and any liabilities assumed) may be adjusted to reflect the final determined amounts, and although the time that is required to identify and measure the fair value of the assets acquired and the liabilities assumed in a business combination will vary with circumstances, generally our allocation period ends when we no longer are waiting for information that is known to be available or obtainable. The results of operations from these acquisitions accounted for as business combinations are included in our consolidated financial statements from the acquisition date.

			Allocation of Purchase Price (in millions)					
Ref.	Date	Acquisition	Purchase Price	Current Assets	Property Plant & Equipment	Deferred Charges & Other	Goodwill	Minority Interest
(1)	1/05	Claytonville Oil Field Unit	$ 6.5	$ —	$ 6.5	$ —	$ —	$ —
(2)	4/05	Texas Petcoke Terminal Region	247.2	—	72.5	161.4	13.3	—
(3)	7/05	Terminal Assets	36.2	0.5	35.7	—	—	—
(4)	7/05	General Stevedores, L.P.	10.4	0.6	5.2	0.2	4.4	—
(5)	8/05	North Dayton Natural Gas Storage Facility	109.4	—	71.7	11.7	26.0	—
(6)	8-9/05	Terminal Assets	4.3	0.4	3.9	—	—	—
(7)	11/05	Allied Terminal Assets	13.3	0.2	12.6	0.5	—	—
(8)	2/06	Entrega Gas Pipeline LLC	244.6	—	244.6	—	—	—
(9)	4/06	Oil and Gas Properties	63.6	0.1	63.5	—	—	—
(10)	4/06	Terminal Assets	61.9	0.5	43.6	—	17.8	—
(11)	11/06	Transload Services, LLC	16.6	1.6	6.6	—	8.4	—
(12)	12/06	Devco USA L.L.C.	7.3	0.8	—	6.5	—	—
(13)	12/06	Roanoke, Virginia Products Terminal	6.4	—	6.4	—	—	—
(14)	1/07	Interest in Cochin Pipeline	47.8	—	47.8	—	—	—
(15)	5/07	Vancouver Wharves Terminal.	57.2	6.5	50.7	—	—	—
(16)	9/07	Marine Terminals, Inc. Assets	101.5	0.2	60.8	40.5	—	—

(1) Claytonville Oil Field Unit

Effective January 31, 2005, we acquired an approximate 64.5% gross working interest in the Claytonville oil field unit located in Fisher County, Texas from Aethon I L.P. The field is located nearly 30 miles east of the SACROC unit in the Permian Basin of West Texas. Our purchase price was approximately $6.5 million, consisting of $6.2 million in cash and the assumption of $0.3 million of liabilities. Following our acquisition, we became the operator of the field, which at the time of acquisition was producing approximately 200 barrels of oil per day. The acquisition of this ownership interest complemented our existing carbon dioxide assets in the Permian Basin and we include the acquired operations as part of our CO_2 business segment.

(2) Texas Petcoke Terminal Region

Effective April 29, 2005, we acquired seven bulk terminal operations from Trans-Global Solutions, Inc. for an aggregate consideration of approximately $247.2 million, consisting of $186.0 million in cash, $46.2 million in common units, and an obligation to pay an additional $15 million on April 29, 2007, two years after the closing. We settled the $15 million liability by issuing additional common units. All of the acquired assets are located in the state of Texas, and include facilities at the Port of Houston, the Port of Beaumont and the TGS Deepwater Terminal located on the Houston Ship Channel. We combined the acquired operations into a new terminal region called the Texas Petcoke region, as certain of the terminals have contracts in place to provide petroleum coke handling services for major Texas oil refineries. The acquisition complemented our existing Gulf Coast terminal facilities and expanded our pre-existing petroleum coke handling operations. The acquired operations are included as part of our Terminals business segment.

Our allocation of the purchase price to assets acquired and liabilities assumed was based on an appraisal of fair market values, which was completed in the fourth quarter of 2005. A total of $13.3 million of goodwill was assigned to our Terminals business segment and the entire amount is expected to be deductible for tax purposes. We believe this acquisition resulted in the recognition of goodwill primarily due to the fact that certain advantageous factors and conditions existed that contributed to our acquisition price exceeding the fair value of acquired identifiable net assets and liabilities —in the aggregate, these factors represented goodwill. The $161.4 million of deferred charges and other assets in the table above represents the fair value of intangible customer relationships, which encompass both the contractual life of customer contracts plus any future customer relationship value beyond the contract life. In connection with the transaction, Trans-Global Solutions, Inc. agreed to indemnify Kinder Morgan G.P., Inc. for any losses relating to our failure to repay $50.9 million of indebtedness incurred to fund the acquisition, and we agreed to indemnify Trans-Global Solutions, Inc. for any taxes of Trans-Global Solutions, Inc. that may arise from the sale of any acquired assets. We have no current intention to sell any of the assets acquired in this transaction.

(3) July 2005 Terminal Assets

In July 2005, we acquired three terminal facilities in separate transactions for an aggregate consideration of approximately $36.2 million in cash. The largest of the transactions was the purchase of a refined petroleum products terminal in New York Harbor from ExxonMobil Oil Corporation. The second acquisition involved a dry-bulk river terminal located in the state of Kentucky, and the third involved a liquids/dry-bulk facility located in Blytheville, Arkansas. The operations of all three facilities are included in our Terminals business segment.

The New York Harbor terminal, located on Staten Island and referred to as the Kinder Morgan Staten Island terminal, complements our existing Northeast liquids terminal facilities located in Carteret and Perth Amboy, New Jersey. At the time of acquisition, the terminal had storage capacity of 2.3 million barrels for gasoline, diesel and fuel oil, and we expected to bring several idle tanks back into service that would add another 550,000 barrels of capacity. As part of the transaction, ExxonMobil entered into a long-term storage capacity agreement with us and has continued to utilize a portion of the terminal. Since our acquisition, we have invested approximately $25 million in terminal improvements, including funds used to rebuild a ship berth with the ability to accommodate tanker vessels. All expansion projects should be complete by the end of the first quarter of 2008.

The dry-bulk terminal, located along the Ohio River in Hawesville, Kentucky, primarily handles wood chips and finished paper products. The acquisition complemented our existing terminal assets located in the Ohio River

Valley and further expanded our wood-chip handling businesses. As part of the transaction, we assumed a long-term handling agreement with Weyerhauser Company, an international forest products company.

The assets acquired at the liquids/dry-bulk facility in Blytheville, Arkansas consisted of storage and supporting infrastructure for 40,000 tons of anhydrous ammonia, 9,500 tons of urea ammonium nitrate solutions and 40,000 tons of urea. As part of the transaction, we have entered into a long-term agreement to sublease all of the existing anhydrous ammonia and urea ammonium nitrate terminal assets to Terra Nitrogen Company, L.P. The terminal is one of only two facilities in the United States that can handle imported fertilizer and provide shipment west on railcars, and the acquisition of the facility positioned us to take advantage of the increase in fertilizer imports that has resulted from the recent decrease in domestic production.

(4) General Stevedores, L.P.

Effective July 31, 2005, we acquired all of the partnership interests in General Stevedores, L.P. for an aggregate consideration of approximately $10.4 million, consisting of $2.0 million in cash, $3.4 million in common units, and $5.0 million in assumed liabilities, including debt of $3.0 million. In August 2005, we paid the $3.0 million outstanding debt balance.

General Stevedores, L.P. owns, operates and leases barge unloading facilities located along the Houston, Texas ship channel. Its operations primarily consist of receiving, storing and transferring semi-finished steel products, including coils, pipe and billets. The acquisition complemented and further expanded our existing Texas Gulf Coast terminal facilities, and its operations are included as part of our Terminals business segment. A total of $4.4 million of goodwill was assigned to our Terminals business segment, and the entire amount is expected to be deductible for tax purposes. We believe this acquisition resulted in the recognition of goodwill primarily due to the fact that certain advantageous factors and conditions existed that contributed to our acquisition price exceeding the fair value of acquired identifiable net assets and liabilities —in the aggregate, these factors represented goodwill.

(5) North Dayton Natural Gas Storage Facility

Effective August 1, 2005, we acquired a natural gas storage facility in Liberty County, Texas, from Texas Genco LLC for an aggregate consideration of approximately $109.4 million, consisting of $52.9 million in cash and $56.5 million in assumed debt. The facility, referred to as our North Dayton storage facility, has approximately 6.3 billion cubic feet of total capacity, consisting of 4.2 billion cubic feet of working capacity and 2.1 billion cubic feet of pad (cushion) gas. The acquisition complemented our existing Texas intrastate natural gas pipeline group assets and positioned us to pursue expansions at the facility that will provide or offer needed services to utilities, the growing liquefied natural gas industry along the Texas Gulf Coast, and other natural gas storage users. Additionally, as part of the transaction, we entered into a long-term storage capacity and transportation agreement with NRG, one of the largest wholesale electric power generating companies in the United States, with over 13,000 megawatts of generation capacity. The agreement covers storage services for approximately 2.0 billion cubic feet of natural gas capacity and expires on March 1, 2017. The North Dayton storage facility's operations are included in our Natural Gas Pipelines business segment.

Our allocation of the purchase price to assets acquired and liabilities assumed was based on an appraisal of fair market values, which was completed in the fourth quarter of 2005. A total of $26.0 million of goodwill was assigned to our Natural Gas Pipelines business segment and the entire amount is expected to be deductible for tax purposes. We believe our acquisition of the North Dayton natural gas storage facility resulted in the recognition of goodwill primarily due to the fact that the favorable location and the favorable association with our pre-existing assets contributed to our acquisition price exceeding the fair value of acquired identifiable net assets and liabilities —in the aggregate, these factors represented goodwill. The $11.7 million of deferred charges and other assets in the table above represents the fair value of the intangible long-term natural gas storage capacity and transportation agreement.

(6) August and September 2005 Terminal Assets

In August and September 2005, we acquired certain terminal facilities and assets, including both real and personal property, in two separate transactions for an aggregate consideration of approximately $4.3 million in cash.

In August 2005, we spent $1.9 million to acquire the Kinder Morgan Blackhawk terminal from White Material Handling, Inc., and in September 2005, we spent $2.4 million to acquire a repair shop and related assets from Trans-Global Solutions, Inc.

The Kinder Morgan Blackhawk terminal consists of approximately 46 acres of land, storage buildings, and related equipment located in Black Hawk County, Iowa. The terminal primarily stores and transfers fertilizer and salt and further expanded our Midwest region bulk terminal operations. The acquisition of the repair shop, located in Jefferson County, Texas, near Beaumont, consists of real and personal property, including parts inventory. The acquisition facilitated and expanded the earlier acquisition of our Texas Petcoke terminals from Trans-Global Solutions in April 2005. The operations of both acquisitions are included in our Terminals business segment.

(7) Allied Terminal Assets

Effective November 4, 2005, we acquired certain terminal assets from Allied Terminals, Inc. for an aggregate consideration of approximately $13.3 million, consisting of $12.1 million in cash and $1.2 million in assumed liabilities. The assets primarily consisted of storage tanks, loading docks, truck racks, land and other equipment and personal property located adjacent to our Shipyard River bulk terminal in Charleston, South Carolina. The acquisition complemented an ongoing capital expansion project at our Shipyard River terminal that together, will add infrastructure in order to increase the terminal's ability to handle increasing supplies of imported coal. The acquired assets are counted as an external addition to our Shipyard River terminal and are included as part of our Terminals business segment.

(8) Entrega Gas Pipeline LLC

Effective February 23, 2006, Rockies Express Pipeline LLC acquired Entrega Gas Pipeline LLC from EnCana Corporation for $244.6 million in cash. West2East Pipeline LLC is a limited liability company and is the sole owner of Rockies Express Pipeline LLC. We contributed 66 2/3% of the consideration for this purchase, which corresponded to our percentage ownership of West2East Pipeline LLC at that time. At the time of acquisition, Sempra Energy held the remaining 33 1/3% ownership interest and contributed this same proportional amount of the total consideration.

On the acquisition date, Entrega Gas Pipeline LLC owned the Entrega Pipeline, an interstate natural gas pipeline that, when fully constructed, consisted of two segments: (i) a 136-mile, 36-inch diameter pipeline that extends from the Meeker Hub in Rio Blanco County, Colorado to the Wamsutter Hub in Sweetwater County, Wyoming and (ii) a 191-mile, 42-inch diameter pipeline that extends from the Wamsutter Hub to the Cheyenne Hub in Weld County, Colorado. In the first quarter of 2006, EnCana Corporation completed construction of the pipeline segment that extends from the Meeker Hub to the Wamsutter Hub, and interim service began on that portion of the pipeline on February 24, 2006. Under the terms of the purchase and sale agreement, Rockies Express Pipeline LLC constructed the segment that extends from the Wamsutter Hub to the Cheyenne Hub. Construction on this pipeline segment began in the second quarter of 2006, and both pipeline segments were placed into service on February 14, 2007. The acquired assets are included in our Natural Gas Pipelines business segment.

In April 2006, Rockies Express Pipeline LLC merged with and into Entrega Gas Pipeline LLC, and the surviving entity was renamed Rockies Express Pipeline LLC. Going forward, the entire pipeline system (including lines currently being developed by Rockies Express Pipeline LLC) will be known as the Rockies Express Pipeline. The combined 1,679-mile pipeline system will be one of the largest natural gas pipelines ever constructed in North America. The approximately $4.9 billion project will have the capability to transport 1.8 billion cubic feet per day of natural gas, and binding firm commitments have been secured for all of the pipeline capacity.

On June 30, 2006, ConocoPhillips exercised its option to acquire a 25% ownership interest in West2East Pipeline LLC. On that date, a 24% ownership interest was transferred to ConocoPhillips, and an additional 1% interest will be transferred once construction of the entire project is completed. Through our subsidiary Kinder Morgan W2E Pipeline LLC, we will continue to operate the project but our ownership interest decreased to 51% of the equity in the project (down from 66 2/3%). Sempra's ownership interest in West2East Pipeline LLC decreased to 25% (down from 33 1/3%). When construction of the entire project is completed, our ownership interest will be reduced to 50% at which time the capital accounts of West2East Pipeline LLC will be trued up to reflect our 50%

economics in the project. We do not anticipate any additional changes in the ownership structure of the Rockies Express Pipeline project.

West2East Pipeline LLC qualifies as a variable interest entity as defined by Financial Accounting Standards Board Interpretation No. 46 (Revised December 2003) (FIN 46R), "Consolidation of Variable Interest Entities-an interpretation of ARB No. 51," due to the fact that the total equity at risk is not sufficient to permit the entity to finance its activities without additional subordinated financial support provided by any parties, including equity holders. Furthermore, following ConocoPhillips' acquisition of its ownership interest in West2East Pipeline LLC on June 30, 2006, we receive 50% of the economics of the Rockies Express project on an ongoing basis, and thus, effective June 30, 2006, we were no longer considered the primary beneficiary of this entity as defined by FIN 46R. Accordingly, on that date, we made the change in accounting for our investment in West2East Pipeline LLC from full consolidation to the equity method following the decrease in our ownership percentage.

Under the equity method, we record the costs of our investment within the "Investments" line on our consolidated balance sheet and as changes in the net assets of West2East Pipeline LLC occur (for example, earnings and dividends), we recognize our proportional share of that change in the "Investment" account. We also record our proportional share of any accumulated other comprehensive income or loss within the "Accumulated other comprehensive loss" line on our consolidated balance sheet.

In addition, we have guaranteed our proportionate share of West2East Pipeline LLC's debt borrowings under a $2 billion credit facility entered into by Rockies Express Pipeline LLC. For more information on our contingent debt, see Note 9.

(9) April 2006 Oil and Gas Properties

On April 5, 2006, Kinder Morgan Production Company L.P. purchased various oil and gas properties from Journey Acquisition – I, L.P. and Journey 2000, L.P. for an aggregate consideration of approximately $63.6 million, consisting of $60.0 million in cash and $3.6 million in assumed liabilities. The acquisition was effective March 1, 2006. However, we divested certain acquired properties that are not considered candidates for carbon dioxide enhanced oil recovery, thus reducing our total investment. We received proceeds of approximately $27.1 million from the sale of these properties.

The properties are primarily located in the Permian Basin area of West Texas, produce approximately 400 barrels of oil equivalent per day, and include some fields with potential for enhanced oil recovery development near our current carbon dioxide operations. The acquired operations are included as part of our CO_2 business segment.

(10) April 2006 Terminal Assets

In April 2006, we acquired terminal assets and operations from A&L Trucking, L.P. and U.S. Development Group in three separate transactions for an aggregate consideration of approximately $61.9 million, consisting of $61.6 million in cash and $0.3 million in assumed liabilities.

The first transaction included the acquisition of equipment and infrastructure on the Houston Ship Channel that loads and stores steel products. The acquired assets complement our nearby bulk terminal facility purchased from General Stevedores, L.P. in July 2005. The second acquisition included the purchase of a rail terminal at the Port of Houston that handles both bulk and liquids products. The rail terminal complements our existing Texas petroleum coke terminal operations and maximizes the value of our existing deepwater terminal by providing customers with both rail and vessel transportation options for bulk products. Thirdly, we acquired the entire membership interest of Lomita Rail Terminal LLC, a limited liability company that owns a high-volume rail ethanol terminal in Carson, California. The terminal serves approximately 80% of the Southern California demand for reformulated fuel blend ethanol with expandable offloading/distribution capacity, and the acquisition expanded our existing rail transloading operations. All of the acquired assets are included in our Terminals business segment. A total of $17.8 million of goodwill was assigned to our Terminals business segment and the entire amount is expected to be deductible for tax purposes.

(11) Transload Services, LLC

Effective November 20, 2006, we acquired all of the membership interests of Transload Services, LLC from Lanigan Holdings, LLC for an aggregate consideration of approximately $16.6 million, consisting of $15.8 million in cash and $0.8 million of assumed liabilities. Transload Services, LLC is a leading provider of innovative, high quality material handling and steel processing services, operating 14 steel-related terminal facilities located in the Chicago metropolitan area and various cities in the United States. Its operations include transloading services, steel fabricating and processing, warehousing and distribution, and project staging. Specializing in steel processing and handling, Transload Services can inventory product, schedule shipments and provide customers cost-effective modes of transportation. The combined operations include over 92 acres of outside storage and 445,000 square feet of covered storage that offers customers environmentally controlled warehouses with indoor rail and truck loading facilities for handling temperature and humidity sensitive products. The acquired assets are included in our Terminals business segment, and the acquisition further expanded and diversified our existing terminals' materials services (rail transloading) operations.

A total of $8.4 million of goodwill was assigned to our Terminals business segment, and the entire amount is expected to be deductible for tax purposes. We believe this acquisition resulted in the recognition of goodwill primarily due to the fact that it establishes a business presence in several key markets, taking advantage of the non-residential and highway construction demand for steel that contributed to our acquisition price exceeding the fair value of acquired identifiable net assets and liabilities —in the aggregate, these factors represented goodwill.

(12) Devco USA L.L.C.

Effective December 1, 2006, we acquired all of the membership interests in Devco USA L.L.C., an Oklahoma limited liability company, for an aggregate consideration of approximately $7.3 million, consisting of $4.8 million in cash, $1.6 million in common units, and $0.9 million of assumed liabilities. The primary asset acquired was a technology based identifiable intangible asset, a proprietary process that transforms molten sulfur into premium solid formed pellets that are environmentally friendly, easy to handle and store, and safe to transport. The process was developed internally by Devco's engineers and employees. Devco, a Tulsa, Oklahoma based company, has more than 20 years of sulfur handling expertise and we believe the acquisition and subsequent application of this acquired technology complements our existing dry-bulk terminal operations. We allocated $6.5 million of our total purchase price to the value of this intangible asset, and we have included the acquisition as part of our Terminals business segment.

(13) Roanoke, Virginia Products Terminal

Effective December 15, 2006, we acquired a refined petroleum products terminal located in Roanoke, Virginia from Motiva Enterprises, LLC for approximately $6.4 million in cash. The terminal has storage capacity of approximately 180,000 barrels per day for refined petroleum products like gasoline and diesel fuel. The terminal is served exclusively by the Plantation Pipeline and Motiva has entered into a long-term contract to use the terminal. The acquisition complemented the other refined products terminals we own in the southeast region of the United States, and the acquired terminal is included as part our Products Pipelines business segment.

(14) Interest in Cochin Pipeline

Effective January 1, 2007, we acquired the remaining approximate 50.2% interest in the Cochin pipeline system that we did not already own for an aggregate consideration of approximately $47.8 million, consisting of $5.5 million in cash and a note payable having a fair value of $42.3 million. As part of the transaction, the seller also agreed to reimburse us for certain pipeline integrity management costs over a five-year period in an aggregate amount not to exceed $50 million. Upon closing, we became the operator of the pipeline.

The Cochin Pipeline is a multi-product liquids pipeline consisting of approximately 1,900 miles of 12-inch diameter pipe operating between Fort Saskatchewan, Alberta, and Windsor, Ontario, Canada. The entire Cochin pipeline system traverses three provinces in Canada and seven states in the United States, serving the Midwestern United States and eastern Canadian petrochemical and fuel markets. Its operations are included as part of our Products Pipelines business segment.

As of December 31, 2007, our allocation of the purchase price was preliminary, pending final determination of deferred income tax balances at the time of acquisition. We expect these final purchase price adjustments to be in the first quarter of 2008.

(15) Vancouver Wharves Terminal

On May 30, 2007, we purchased the Vancouver Wharves bulk marine terminal from British Columbia Railway Company, a crown corporation owned by the Province of British Columbia, for an aggregate consideration of $57.2 million, consisting of $38.8 million in cash and $18.4 million in assumed liabilities. The Vancouver Wharves facility is located on the north shore of the Port of Vancouver's main harbor, and includes five deep-sea vessel berths situated on a 139-acre site. The terminal assets include significant rail infrastructure, dry bulk and liquid storage, and material handling systems which allow the terminal to handle over 3.5 million tons of cargo annually. Vancouver Wharves also has access to three major rail carriers connecting to shippers in western and central Canada, and the U.S. Pacific Northwest. The acquisition both expanded and complemented our existing terminal operations, and all of the acquired assets are included in our Terminals business segment.

(16) Marine Terminals, Inc. Assets

Effective September 1, 2007, we acquired certain bulk terminals assets from Marine Terminals, Inc. for an aggregate consideration of approximately $101.5 million, consisting of $100.3 million in cash and an assumed liability of $1.2 million. The acquired assets and operations are primarily involved in the handling and storage of steel and alloys, and also provide stevedoring and harbor services, scrap handling, and scrap processing services to customers in the steel and alloys industry. The operations consist of two separate facilities located in Blytheville, Arkansas, and individual terminal facilities located in Decatur, Alabama, Hertford, North Carolina, and Berkley, South Carolina. Combined, the five facilities handled approximately 13.4 million tons of steel products in 2006. Under long-term contracts, the acquired terminal facilities will continue to provide handling, processing, harboring and warehousing services to Nucor Corporation, one of the nation's largest steel and steel products companies.

As of December 31, 2007, we have preliminarily allocated $60.8 million of our combined purchase price to "Property, Plant and Equipment, net". The $40.5 million allocated to deferred charges and other assets included $39.7 million of intangible assets, representing the fair value of intangible customer relationships which encompass both the contractual life of customer contracts plus any future customer relationship value beyond the contract life. We expect to make further purchase price adjustments to the acquired assets in the first half of 2008, based on further analysis of fair market values. The acquisition both expanded and complemented our existing ferro alloy terminal operations and will provide Nucor and other customers further access to our growing national network of marine and rail terminals. All of the acquired assets are included in our Terminals business segment.

Pro Forma Information

Pro forma income statement information that assumes all of the acquisitions we have made and joint ventures we have entered into since January 1, 2006, including the ones listed above, had occurred as of January 1, 2006, is not materially different from the information presented in our accompanying consolidated statements of income.

Trans Mountain Pipeline System

On April 30, 2007, we acquired the Trans Mountain pipeline system from Knight for $549.1 million in cash. The transaction was approved by the independent directors of both Knight and KMR following the receipt, by such directors, of separate fairness opinions from different investment banks. We paid $549 million of the purchase price on April 30, 2007, and we paid the remaining $0.1 million in July 2007.

Effective January 1, 2006, Knight (formerly KMI), our ultimate parent, according to the provisions of Emerging Issues Task Force Issue No. 04-5, "Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights," was deemed to have control over us and no longer accounted for its investment in us under the equity method of accounting, but instead included our accounts, balances and results of operations in its consolidated financial statements. As required by the provisions of SFAS No. 141, we accounted for our acquisition of Trans Mountain as a transfer of net assets between entities under common control. For combinations of entities under common control, the purchase cost provisions (as they relate to purchase business combinations involving unrelated entities) of SFAS No. 141 explicitly do not apply; instead the method of accounting prescribed by SFAS No. 141 for such transfers is similar to the pooling-of-interests method of accounting. Under this method, the carrying amount of net assets recognized in the balance sheets of each combining entity are carried forward to the balance sheet of the combined entity, and no other assets or liabilities are recognized as a result of the combination (that is, no recognition is made for a purchase premium or discount representing any difference between the cash consideration paid and the book value of the net assets acquired).

Therefore, following our acquisition of Trans Mountain from Knight on April 30, 2007, we recognized the Trans Mountain assets and liabilities acquired at their carrying amounts (historical cost) in the accounts of Knight (the transferring entity) at the date of transfer. The accounting treatment for combinations of entities under common control is consistent with the concept of poolings as combinations of common shareholder (or unitholder) interests, as all of Trans Mountain's equity accounts were also carried forward intact initially, and subsequently adjusted due to the cash consideration we paid for the acquired net assets.

In addition to requiring that assets and liabilities be carried forward at historical costs, SFAS No. 141 also prescribes that for transfers of net assets between entities under common control, all income statements presented be combined as of the date of common control. Accordingly, our consolidated financial statements and all other financial information included in this report have been restated to assume that the transfer of Trans Mountain net assets from Knight to us had occurred at the date when both Trans Mountain and we met the accounting requirements for entities under common control (January 1, 2006). As a result, financial statements and financial information presented for prior periods in this report have been restated. These restatements include Knight's recognition of a goodwill impairment expense of $377.1 million recorded in the first quarter of 2007. For more information on this impairment expense, see Note 6.

The Trans Mountain pipeline system, which transports crude oil and refined products from Edmonton, Alberta, Canada to marketing terminals and refineries in British Columbia and the state of Washington, recently completed a pump station expansion and currently transports approximately 260,000 barrels per day. An additional 35,000 barrel per day expansion that will increase capacity of the pipeline to 300,000 barrels per day is expected to be in service by November 2008. In addition, due to the fact that Trans Mountain's operations are managed separately, involve different products and marketing strategies, and produce discrete financial information that is separately evaluated internally by our management, we have identified our Trans Mountain pipeline system as a separate reportable business segment.

Divestitures

Douglas Gas Gathering and Painter Gas Fractionation

Effective April 1, 2006, we sold our Douglas natural gas gathering system and our Painter Unit fractionation facility to Momentum Energy Group, LLC for approximately $42.5 million in cash. Our investment in the net assets we sold in this transaction, including all transaction related accruals, was approximately $24.5 million, most of which represented property, plant and equipment, and we recognized approximately $18.0 million of gain on the sale of these net assets. We used the proceeds from these asset sales to reduce the outstanding balance on our commercial paper borrowings.

Additionally, upon the sale of our Douglas gathering system, we reclassified a net loss of $2.9 million from "Accumulated other comprehensive loss" into net income on those derivative contracts that effectively hedged uncertain future cash flows associated with forecasted Douglas gathering transactions. We included the net amount of the gain, $15.1 million, within the caption "Other expense (income)" in our accompanying consolidated statement of income for the year ended December 31, 2006. For more information on our accounting for derivative contracts, see Note 14.

The Douglas gathering system is comprised of approximately 1,500 miles of 4-inch to 16-inch diameter pipe that gathers approximately 26 million cubic feet per day of natural gas from approximately 650 active receipt points.

Gathered volumes are processed at our Douglas plant (which we retained), located in Douglas, Wyoming. As part of the transaction, we executed a long-term processing agreement with Momentum Energy Group, LLC which dedicates volumes from the Douglas gathering system to our Douglas processing plant. The Painter Unit, located near Evanston, Wyoming, consists of a natural gas processing plant and fractionator, a nitrogen rejection unit, a natural gas liquids terminal, and interconnecting pipelines with truck and rail loading facilities. Prior to the sale, we leased the plant to BP, which operated the fractionator and the associated Millis terminal and storage facilities for its own account.

North System Natural Gas Liquids Pipeline System – Discontinued Operations

On July 2, 2007, we announced that we entered into an agreement to sell the North System natural gas liquids pipeline and our 50% ownership interest in the Heartland Pipeline Company (collectively referred to in this report as our North System) to ONEOK Partners, L.P. for approximately $298.6 million in cash. Our investment in net assets, including all transaction related accruals, was approximately $145.8 million, most of which represented property, plant and equipment, and we recognized approximately $152.8 million of gain on the sale of these net assets.

The North System consists of an approximately 1,600-mile interstate common carrier pipeline system that delivers natural gas liquids and refined petroleum products from south central Kansas to the Chicago area. Also included in the sale were eight propane truck-loading terminals, located at various points in three states along the pipeline system, and one multi-product terminal complex located in Morris, Illinois. Prior to the sale, all of the assets were included in our Products Pipelines business segment.

In accordance with SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," we accounted for the North System business as a discontinued operation whereby the financial results of the North System have been reclassified to discontinued operations in our accompanying consolidated statements of income for all periods presented in this report. We reported the net amount of the gain, $152.8 million, with the caption "Gain on disposal of North System" within the discontinued operations section of our accompanying consolidated statement of income for the year ended December 31, 2007.

Summarized financial information of the North System is as follows (in millions):

	Year Ended December 31,		
	2007	**2006**	**2005**
Operating revenues	$ 41.1	$ 43.7	$ 41.2
Operating expenses	(14.8)	(22.7)	(35.2)
Depreciation and amortization	(7.0)	(8.9)	(8.2)
Earnings from equity investments	1.8	2.2	2.1
Amortization of excess cost of equity investments	—	(0.1)	(0.1)
Other, net – income (expense)	—	0.1	—
Income (loss) from operations	21.1	14.3	(0.2)
Income from disposal	152.8	—	—
Total earnings from discontinued operations	$ 173.9	$ 14.3	$ (0.2)

In our accompanying consolidated statements of cash flows, we elected to not separately present the North System's operating and investing cash flows as discontinued operations, and, due to the fact that the sale of the North System does not change the structure of our internal organization in a manner that causes a change to our reportable business segments pursuant to the provisions of SFAS No. 131, "Disclosures about Segments of an Enterprise and Related Information," we have included the North System's financial disclosures within our Products Pipelines business segment disclosures for all periods presented in this report.

4. Asset Retirement Obligations

We account for our legal obligations associated with the retirement of long-lived assets pursuant to Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations." SFAS No. 143 provides accounting and reporting guidance for legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction or normal operation of a long-lived asset.

SFAS No. 143 requires companies to record a liability relating to the retirement and removal of assets used in their businesses. Under SFAS No. 143, the fair value of asset retirement obligations are recorded as liabilities on a discounted basis when they are incurred, which is typically at the time the assets are installed or acquired. Amounts recorded for the related assets are increased by the amount of these obligations. Over time, the liabilities will be accreted for the change in their present value and the initial capitalized costs will be depreciated over the useful lives of the related assets. The liabilities are eventually extinguished when the asset is taken out of service.

In our CO_2 business segment, we are required to plug and abandon oil and gas wells that have been removed from service and to remove our surface wellhead equipment and compressors. As of December 31, 2007 and 2006, we have recognized asset retirement obligations relating to these requirements at existing sites within our CO_2 segment in the aggregate amounts of $49.2 million and $47.2 million, respectively.

In our Natural Gas Pipelines business segment, if we were to cease providing utility services, we would be required to remove surface facilities from land belonging to our customers and others. We believe we can reasonably estimate both the time and costs associated with the retirement of these facilities. As of December 31, 2007 and 2006, we have recognized asset retirement obligations relating to the businesses within our Natural Gas Pipelines segment in the aggregate amounts of $3.0 million and $3.1 million, respectively.

We have included $1.4 million of our total asset retirement obligations as of both December 31, 2007 and December 31, 2006 within "Accrued other current liabilities" in our accompanying consolidated balance sheets. The remaining $50.8 million obligation as of December 31, 2007 and $48.9 million obligation as of December 31, 2006 are reported separately as non-current liabilities in our accompanying consolidated balance sheets. No assets are legally restricted for purposes of settling our asset retirement obligations. A reconciliation of the beginning and ending aggregate carrying amount of our asset retirement obligations for each of the years ended December 31, 2007 and 2006 is as follows (in millions):

	Year Ended December 31,	
	2007	**2006**
Balance at beginning of period	$ 50.3	$ 43.2
Liabilities incurred	0.4	6.8
Liabilities settled	(1.1)	(2.2)
Accretion expense	2.6	2.5
Revisions in estimated cash flows	—	—
Balance at end of period	$ 52.2	$ 50.3

We have various other obligations throughout our businesses to remove facilities and equipment on rights-of- way and other leased facilities. We currently cannot reasonably estimate the fair value of these obligations because the associated assets have indeterminate lives. These assets include pipelines, certain processing plants and distribution facilities, and certain bulk and liquids terminal facilities. An asset retirement obligation, if any, will be recognized once sufficient information is available to reasonably estimate the fair value of the obligation.

5. Income Taxes

Components of the income tax provision applicable to continuing operations for federal, foreign and state taxes are as follows (in millions):

	Year Ended December 31,		
	2007	2006	2005
Taxes currently payable:			
Federal	$ 12.7	$ 12.8	$ 9.6
State	8.2	2.3	2.1
Foreign	31.5	11.2	0.4
Total	52.4	26.3	12.1
Taxes deferred:			
Federal	11.8	1.6	8.1
State	6.2	0.2	0.8
Foreign	0.6	0.9	3.5
Total	18.6	2.7	12.4
Total tax provision	$ 71.0	$ 29.0	$ 24.5
Effective tax rate	14.6%	2.8%	2.9%

The difference between the statutory federal income tax rate and our effective income tax rate is summarized as follows:

	Year Ended December 31,		
	2007	2006	2005
Federal income tax rate	35.0%	35.0%	35.0%
Increase (decrease) as a result of:			
Partnership earnings not subject to tax	(35.0)%	(35.0)%	(35.0)%
Corporate subsidiary earnings subject to tax	3.0%	1.0%	1.1%
Income tax expense attributable to corporate equity earnings	2.3%	0.5%	1.1%
Income tax expense attributable to foreign corporate earnings	6.6%	1.1%	0.5%
State taxes	2.7%	0.2%	0.2%
Effective tax rate	14.6%	2.8%	2.9%

Our deferred tax assets and liabilities as of December 31, 2007 and 2006 result from the following (in millions):

	December 31,	
	2007	2006
Deferred tax assets:		
Book accruals	$ 13.1	$ 1.4
Net Operating Loss/Alternative minimum tax credits	1.2	3.0
Other	1.7	1.3
Total deferred tax assets	16.0	5.7
Deferred tax liabilities:		
Property, plant and equipment	189.9	106.9
Other	28.5	84.0
Total deferred tax liabilities	218.4	190.9
Net deferred tax liabilities	$202.4	$185.2

We had available, at December 31, 2007, approximately $0.13 million of foreign minimum tax credit carryforwards, which will expire between the years 2013 and 2016, and $1.1 million of state net operating loss carryforwards, which will expire between the years 2008 and 2025. We believe it is more likely than not that the net operating loss carryforwards will be utilized prior to their expiration; therefore, no valuation allowance is necessary.

6. Property, Plant and Equipment

Classes and Depreciation

As of December 31, 2007 and 2006, our property, plant and equipment consisted of the following (in millions):

	December 31, 2007	December 31, 2006
Natural gas, liquids, crude oil and carbon dioxide pipelines	$ 5,498.4	$ 4,795.9
Natural gas, liquids, carbon dioxide pipeline, and terminals station equipment	5,076.2	4,549.3
Natural gas, liquids (including linefill), and transmix processing	168.3	172.7
Other	1,060.4	844.9
Accumulated depreciation and depletion	(2,044.0)	(1,641.2)
	9,759.3	8,721.6
Land and land right-of-way	551.5	532.9
Construction work in process	1,280.5	851.6
Property, Plant and Equipment, net	$ 11,591.3	$ 10,106.1

Depreciation and depletion expense charged against property, plant and equipment consisted of $529.3 million in 2007, $416.6 million in 2006 and $339.6 million in 2005.

Casualty Gain

On August 29, 2005, Hurricane Katrina made landfall in the United States Gulf Coast causing widespread damage to residential and commercial real and personal property. In addition, on September 23, 2005, Hurricane Rita struck the Texas-Louisiana Gulf Coast causing additional damage to insured interests. The primary assets we operate that were impacted by these storms included several bulk and liquids terminal facilities located in the states of Louisiana and Mississippi, and certain of our Gulf Coast liquids terminals facilities, which are located along the Houston Ship Channel. Specifically, with regard to physical property damage, our International Marine Terminals facility suffered extensive property damage and a general loss of business due to the effects of Hurricane Katrina. IMT is a Louisiana partnership owned 66 2/3% by us. It operates a multi-purpose bulk commodity transfer terminal facility located in Port Sulphur, Louisiana.

All of our terminal facilities affected by these storms are currently open, and all of the facilities are covered by property casualty insurance. Some of the facilities are also covered by business interruption insurance. To account for our property casualty damage, we recognized repair expense related to hurricane damage as incurred. We also transferred off our books the net book value of the assets that were damaged or destroyed, and we offset the book value of all damaged and destroyed assets with indemnity proceeds received (and receivable in the future) according to the provisions of the insurance policies in force. We also incurred capital expenditures related to the repair and replacement of damaged assets.

When an insured asset is damaged or destroyed, the relevant accounts must be adjusted to the date of the casualty, and settlement with the insurance companies must be completed. The maximum amount recoverable from property damage is the fair market value of the property at the date of loss (the replacement value), or the amount stipulated in the insurance contract. Although net book values are irrelevant in determining indemnifications from insurers, under current accounting provisions, asset book values are used for accounting purposes to measure the gain or loss resulting from casualty settlements. Also, because indemnifications under insurance policies are based upon fair market values, indemnifications often exceed the book value of the assets destroyed or damaged, and any excess of insurance indemnifications over the book value of damaged assets represents a book casualty gain.

In the fourth quarter of 2006, we reached settlements with our insurance carriers on all of our property damage claims related to the 2005 hurricane season, including IMT’s claims. As a result of these settlements, we recognized a property casualty gain of $15.2 million, excluding all hurricane repair and clean-up expenses. This casualty gain represented the excess of indemnity proceeds received or recoverable over the book value of damaged or destroyed assets. We also collected, in 2006, property insurance indemnities of $13.1 million, and we disclosed these cash receipts separately as "Property casualty indemnifications" within investing activities on our accompanying consolidated statement of cash flows. In addition, as of December 31, 2006, we signed proofs of loss totaling $8.0 million for expected future property damage proceeds, and we received these indemnity proceeds in January 2007.

With the settlement of these claims, we released all remaining estimated property insurance receivables and estimated property insurance-related damage claim amounts, as these hurricane property damage claims are now closed; however, we did recognize additional casualty gains of approximately $1.8 million in the first quarter of 2007 (before minority interest allocations), based upon our final determination of the book value of the fixed assets destroyed or damaged, and indemnities pursuant to flood insurance coverage.

In addition to this casualty gain, 2006 income and expense items related to hurricane activity included the following: (i) a $2.8 million increase in operating and maintenance expenses from hurricane repair and clean-up activities, (ii) a $1.1 million increase in income tax expense associated with overall hurricane income and expense items, (iii) a $0.4 million decrease in general and administrative expenses from the allocation of overhead expenses to hurricane related capital projects, and (iv) a $3.1 million increase in minority interest expense related to the allocation of IMT's earnings from hurricane income and expense items to minority interest. Combined, the hurricane income and expense items, including the casualty gain, resulted in a total increase in net income of $8.6 million in 2006. For the year 2006, we spent approximately $12.2 million for hurricane repair and replacement costs and including accruals, sustaining capital expenditures for hurricane repair and replacement costs totaled $14.2 million.

7. Investments

Our significant equity investments as of December 31, 2007 consisted of:

- Plantation Pipe Line Company (51%);
- West2East Pipeline LLC (51%);
- Red Cedar Gathering Company (49%);
- Midcontinent Express Pipeline LLC (50%);
- Thunder Creek Gas Services, LLC (25%); and
- Cortez Pipeline Company (50%).

We operate and own an approximate 51% ownership interest in Plantation Pipe Line Company, and an affiliate of ExxonMobil owns the remaining approximate 49% interest. Each investor has an equal number of directors on Plantation's board of directors, and board approval is required for certain corporate actions that are considered participating rights. Therefore, we do not control Plantation Pipe Line Company, and we account for our investment under the equity method of accounting.

Similarly, we operate and own a 51% ownership interest in West2East Pipeline LLC, a limited liability company that is the sole owner of Rockies Express Pipeline LLC. ConocoPhillips owns a 24% ownership interest in West2East Pipeline LLC and Sempra Energy holds the remaining 25% interest. As discussed in Note 3, when construction of the entire Rockies Express Pipeline project is completed, our ownership interest will be reduced to 50% at which time the capital accounts of West2East Pipeline LLC will be trued up to reflect our 50% economics in the project. According to the provisions of current accounting standards, due to the fact that we will receive 50% of the economics of the Rockies Express project on an ongoing basis, we are not considered the primary beneficiary of West2East Pipeline LLC and thus, we account for our investment under the equity method of accounting. Prior to June 30, 2006, we owned a 66 2/3% ownership interest in West2East Pipeline LLC and we accounted for our investment under the full consolidation method. Following the decrease in our ownership interest to 51% effective June 30, 2006, we deconsolidated this entity and began to account for our investment under the equity method. As of December 31, 2006, we had no material investment in the net assets of West2East Pipeline LLC due to the fact that the amount of its assets, primarily property, plant and equipment, was largely offset by the amount of its liabilities, primarily debt.

We also own a 50% interest in Midcontinent Express Pipeline LLC, which filed an application with the FERC in October 2007 requesting a certificate of public convenience and necessity that would authorize construction and operation of an approximate 500-mile natural gas transmission system. Energy Transfer Partners, L.P. owns the remaining 50% interest. The Midcontinent Express Pipeline will create long-haul, firm natural gas transportation takeaway capacity, either directly or indirectly, from natural gas producing regions located in Texas, Oklahoma and Arkansas. The total project is expected to cost approximately $1.3 billion, and will have an initial transportation capacity of approximately 1.4 billion cubic feet per day of natural gas. Furthermore, in January 2008, Midcontinent Express and MarkWest Pioneer, L.L.C., a subsidiary of MarkWest Energy Partners, L.P., entered into an option agreement which provides MarkWest a one-time right to purchase a 10% ownership interest in Midcontinent Express after the pipeline is fully constructed and placed into service. If the option is exercised, we and Energy Transfer Partners will each own 45% of Midcontinent Express, while MarkWest will own the remaining 10%.

Our total investments consisted of the following (in millions):

	December 31,	
	2007	**2006**
Plantation Pipe Line Company	$ 195.4	$ 199.6
West2East Pipeline LLC	191.9	—
Red Cedar Gathering Company	135.6	160.6
Midcontinent Express Pipeline LLC	63.0	—
Thunder Creek Gas Services, LLC	37.0	37.2
Cortez Pipeline Company	14.2	16.2
All Others	18.3	12.7
Total Equity Investments	$ 655.4	$ 426.3

Our earnings (losses) from equity investments were as follows (in millions):

	Year Ended December 31,		
	2007	**2006**	**2005**
Red Cedar Gathering Company	$ 28.0	$ 36.3	$ 32.0
Cortez Pipeline Company	19.2	19.2	26.3
Plantation Pipe Line Company	29.4	12.8	24.9
Thunder Creek Gas Services, LLC	2.2	2.4	2.8
Midcontinent Express Pipeline LLC	1.4	—	—
West2East Pipeline LLC	(12.4)	—	—
All Others	1.9	3.3	3.6
Total	$ 69.7	$ 74.0	$ 89.6
Amortization of excess costs	$ (5.8)	$ (5.6)	$ (5.5)

Summarized combined unaudited financial information for our significant equity investments (listed above) is reported below (in millions; amounts represent 100% of investee financial information):

	Year Ended December 31,		
Income Statement	**2007**	**2006**	**2005**
Revenues	$ 473.0	$ 441.9	$ 440.7
Costs and expenses	355.1	299.5	279.6
Earnings before extraordinary items and cumulative effect of a change in accounting principle	117.9	142.4	161.1
Net income	$ 117.9	$ 142.4	$ 161.1

	December 31,	
Balance Sheet	**2007**	**2006**

Current assets	$ 138.3	$ 95.5
Non-current assets	3,519.5	1,506.0
Current liabilities	319.5	213.2
Non-current liabilities	2,624.1	1,127.3
Partners'/owners' equity	714.2	261.0

8. Intangibles

Our intangible assets include goodwill, lease value, contracts, customer relationships, technology-based assets and agreements.

Goodwill and Excess Investment Cost

As an investor, the price we pay to acquire an ownership interest in an investee will most likely differ from the underlying interest in book value, with book value representing the investee's net assets per its financial statements. This differential relates to both discrepancies between the investee's recognized net assets at book value and at current fair values and to any premium we pay to acquire the investment. Under ABP No. 18, any such premium paid by an investor, which is analogous to goodwill, must be identified.

For our investments in affiliated entities that are included in our consolidation, the excess cost over underlying fair value of net assets is referred to as goodwill and reported separately as "Goodwill" in our accompanying consolidated balance sheets. Goodwill is not subject to amortization but must be tested for impairment at least annually. This test requires goodwill to be assigned to an appropriate reporting unit and to determine if the implied fair value of the reporting unit's goodwill is less than its carrying amount.

Changes in the carrying amount of our goodwill for each of the two years ended December 31, 2006 and 2007 are summarized as follows (in millions):

	Products Pipelines	Natural Gas Pipelines	CO_2	Terminals	Trans Mountain(a)	Total
Balance as of December 31, 2005	$ 263.2	$ 288.4	$ 46.1	$ 201.3	$ —	$ 799.0
Acquisitions and purchase price adjs.	—	—	—	30.0	593.2	623.2
Disposals	—	—	—	—	—	—
Impairments	—	—	—	—	—	—
Currency translation adjustments	—	—	—	—	(1.2)	(1.2)
Balance as of December 31, 2006	$ 263.2	$ 288.4	$ 46.1	$ 231.3	$ 592.0	$ 1,421.0
Acquisitions and purchase price adjs.	—	—	—	(2.2)	—	(2.2)
Disposals	—	—	—	—	—	—
Impairments	—	—	—	—	(377.1)	(377.1)
Currency translation adjustments	—	—	—	—	36.1	36.1
Balance as of December 31, 2007	$ 263.2	$ 288.4	$ 46.1	$ 229.1	$ 251.0	$ 1,077.8

(a) On April 18, 2007, we announced that we would acquire the Trans Mountain pipeline system from Knight (formerly KMI), and this transaction was completed April 30, 2007 (discussed in Note 3). Following the provisions of generally accepted accounting principles, this transaction caused Knight to consider the fair value of the Trans Mountain pipeline system, and to determine whether goodwill related to these assets was impaired. Knight recorded a goodwill impairment charge of $377.1 million in the first quarter of 2007.

For our investments in entities that are not fully consolidated but instead are included in our financial statements under the equity method of accounting, the premium we pay that represents excess cost over underlying fair value of net assets is referred to as equity method goodwill, and under SFAS No. 142, this excess cost is not subject to amortization but rather to impairment testing pursuant to APB No. 18. The impairment test under APB No. 18 considers whether the fair value of the equity investment as a whole, not the underlying net assets, has declined and whether that decline is other than temporary. Therefore, in addition to our annual impairment test of goodwill, we periodically reevaluate the amount at which we carry the excess of cost over fair value of net assets accounted for under the equity method, as well as the amortization period for such assets, to determine whether current events or circumstances warrant adjustments to our carrying value and/or revised estimates of useful lives in accordance with APB Opinion No. 18. As of both December 31, 2007 and 2006, we have reported $138.2 million in equity method goodwill within the caption "Investments" in our accompanying consolidated balance sheets.

We also periodically reevaluate the difference between the fair value of net assets accounted for under the equity method and our proportionate share of the underlying book value (that is, the investee's net assets per its financial statements) of the investee at date of acquisition. In almost all instances, this differential, relating to the discrepancy between our share of the investee's recognized net assets at book values and at current fair values, represents our share of undervalued depreciable assets, and since those assets (other than land) are subject to depreciation, we amortize this portion of our investment cost against our share of investee earnings. We reevaluate this differential, as well as the amortization period for such undervalued depreciable assets, to determine whether current events or circumstances warrant adjustments to our carrying value and/or revised estimates of useful lives in accordance with

APB Opinion No. 18. The caption "Investments" in our accompanying consolidated balance sheets includes excess fair value of net assets over book value costs of $174.7 million as of December 31, 2007 and $177.1 million as of December 31, 2006.

Other Intangibles

Excluding goodwill, our other intangible assets include customer relationships, contracts and agreements, technology-based assets, and lease value. These intangible assets have definite lives, are being amortized on a straight-line basis over their estimated useful lives, and are reported separately as "Other intangibles, net" in our accompanying consolidated balance sheets. Following is information related to our intangible assets subject to amortization (in millions):

	December 31, 2007	December 31, 2006
Customer relationships, contracts and agreements		
Gross carrying amount	$ 264.1	$ 224.4
Accumulated amortization	(36.9)	(23.1)
Net carrying amount	227.2	201.3
Technology-based assets, lease value and other		
Gross carrying amount	13.3	13.3
Accumulated amortization	(1.9)	(1.4)
Net carrying amount	11.4	11.9
Total Other intangibles, net	$ 238.6	$ 213.2

The increase in the carrying amount of customer relationships, contracts and agreements since December 31, 2006 was primarily due to the acquisition of intangible customer relationships included in our purchase of certain assets from Marine Terminals, Inc. effective September 1, 2007. As of the acquisition date, we preliminarily allocated $39.8 million of our combined purchase price for Marine Terminals, Inc.'s assets to intangible customer relationships, and we estimated the expected useful life of these intangibles to be 20 years. For more information on this acquisition, see Note 3.

Amortization expense on our intangibles consisted of the following (in millions):

	Year Ended December 31,		
	2007	2006	2005
Customer relationships, contracts and agreements	$ 13.8	$ 13.5	$ 8.6
Technology-based assets, lease value and other	0.5	0.2	0.1
Total amortization	$ 14.3	$ 13.7	$ 8.7

As of December 31, 2007, our weighted average amortization period for our intangible assets was approximately 18.25 years. Our estimated amortization expense for these assets for each of the next five fiscal years is approximately $15.5 million, $14.4 million, $14.2 million, $14.1 million and $14.1 million, respectively.

9. Debt

Short-Term Debt

Our outstanding short-term debt as of December 31, 2007 and 2006 consisted of the following (in millions):

	December 31, 2007	December 31, 2006
Commercial paper borrowings	$ 589.1	$ 1,098.2
Short-term portion of:		
5.35% senior notes due August 15, 2007	—	250.0
5.40% note due March 31, 2012(a)	9.9	—

5.23% senior notes due January 2, 2014(b)	6.2	5.9
7.84% senior notes due July 23, 2008(c)	5.0	5.0
Total short-term debt	$ 610.2	$ 1,359.1

(a) Our subsidiaries, Kinder Morgan Operating L.P. "A" and Kinder Morgan Canada Company, are the obligors on the note.

(b) Our subsidiary, Kinder Morgan Texas Pipeline, L.P., is the obligor on the notes.

(c) Our subsidiary, Central Florida Pipe Line LLC, is the obligor on the notes.

The weighted average interest rate on all of our borrowings was approximately 6.40% during 2007 and 6.18% during 2006.

Credit Facilities

On February 22, 2006, we entered into a second unsecured bank credit facility, a nine-month credit facility in the amount of $250 million, expiring on November 21, 2006. This facility contained borrowing rates and restrictive financial covenants that were similar to the borrowing rates and covenants under our pre-existing five-year unsecured $1.6 billion bank facility due August 18, 2010.

Effective August 28, 2006, we terminated our $250 million nine-month facility and we increased our five-year bank credit facility from $1.6 billion to $1.85 billion. The five-year unsecured bank credit facility remains due August 18, 2010; however, the bank facility can be amended to allow for borrowings up to $2.1 billion. There were no borrowings under our five-year credit facility as of December 31, 2007 or as of December 31, 2006.

Our five-year credit facility is with a syndicate of financial institutions and Wachovia Bank, National Association is the administrative agent. As of December 31, 2007, the amount available for borrowing under our credit facility was reduced by an aggregate amount of $1,126.9 million, consisting of (i) our outstanding commercial paper borrowings ($589.1 million as of December 31, 2007); (ii) a combined $298 million in three letters of credit that support our hedging of commodity price risks associated with the sale of natural gas, natural gas liquids and crude oil; (iii) a $100 million letter of credit that supports certain proceedings with the California Public Utilities Commission involving refined products tariff charges on the intrastate common carrier operations of our Pacific operations' pipelines in the state of California; (iv) a combined $46.6 million in two letters of credit that support tax-exempt bonds; (v) a $19.9 million letter of credit that supports the construction of our Kinder Morgan Louisiana Pipeline (a natural gas pipeline); (vi) a $37.5 million letter of credit that supports our indemnification obligations on the Series D note borrowings of Cortez Capital Corporation; and (vii) a combined $35.8 million in other letters of credit supporting other obligations of us and our subsidiaries.

Our five-year credit facility permits us to obtain bids for fixed rate loans from members of the lending syndicate. Interest on our credit facility accrues at our option at a floating rate equal to either (i) the administrative agent's base rate (but not less than the Federal Funds Rate, plus 0.5%); or (ii) LIBOR, plus a margin, which varies depending upon the credit rating of our long-term senior unsecured debt.

Our credit facility included the following restrictive covenants as of December 31, 2007:

- total debt divided by earnings before interest, income taxes, depreciation and amortization for the preceding four quarters may not exceed:
  - 5.5, in the case of any such period ended on the last day of (i) a fiscal quarter in which we make any Specified Acquisition, or (ii) the first or second fiscal quarter next succeeding such a fiscal quarter; or
  - 5.0, in the case of any such period ended on the last day of any other fiscal quarter;
- certain limitations on entering into mergers, consolidations and sales of assets;
- limitations on granting liens; and
- prohibitions on making any distribution to holders of units if an event of default exists or would exist upon making such distribution.

In addition to normal repayment covenants, under the terms of our credit facility, the occurrence at any time of any of the following would constitute an event of default (i) our failure to make required payments of any item of indebtedness or any payment in respect of any hedging agreement, provided that the aggregate outstanding principal amount for all such indebtedness or payment obligations in respect of all hedging agreements is equal to or exceeds $75 million; (ii) our general partner's failure to make required payments of any item of indebtedness, provided that the aggregate outstanding principal amount for all such indebtedness is equal to or exceeds $75 million; (iii) adverse judgments rendered against us for the payment of money in an aggregate amount in excess of $75 million, if this same amount remains undischarged for a period of thirty consecutive days during which execution shall not be effectively stayed; and (iv) voluntary or involuntary commencements of any proceedings or petitions seeking our liquidation, reorganization or any other similar relief under any federal, state or foreign bankruptcy, insolvency, receivership or similar law.

Excluding the relatively non-restrictive specified negative covenants and events of defaults, our credit facility does not contain any provisions designed to protect against a situation where a party to an agreement is unable to find a basis to terminate that agreement while its counterparty's impending financial collapse is revealed and perhaps hastened through the default structure of some other agreement. The credit facility also does not contain a material adverse change clause coupled with a lockbox provision; however, the facility does provide that the margin we will pay with respect to borrowings and the facility fee that we will pay on the total commitment will vary based on our senior debt investment rating. None of our debt is subject to payment acceleration as a result of any change to our credit ratings.

Commercial Paper Program

In April 2006, we increased our commercial paper program by $250 million to provide for the issuance of up to $1.85 billion. Our $1.85 billion unsecured five-year bank credit facility supports our commercial paper program, and borrowings under our commercial paper program reduce the borrowings allowed under our credit facility. As of December 31, 2007, we had $589.1 million of commercial paper outstanding with a weighted average interest rate of 5.58%. As of December 31, 2006, we had $1,098.2 million of commercial paper outstanding with an average interest rate of 5.42%. The borrowings under our commercial paper program were used principally to finance the acquisitions and capital expansions we made during 2007 and 2006.

Long-Term Debt

Our outstanding long-term debt, excluding the value of interest rate swaps, as of December 31, 2007 and 2006 was $6,455.9 million and $4,384.3 million, respectively. The balances consisted of the following (in millions):

	December 31,	
	2007	2006
Kinder Morgan Energy Partners, L.P. borrowings:		
5.35% senior notes due August 15, 2007	$ —	$ 250.0
6.30% senior notes due February 1, 2009	250.0	250.0
7.50% senior notes due November 1, 2010	250.0	250.0
6.75% senior notes due March 15, 2011	700.0	700.0
7.125% senior notes due March 15, 2012	450.0	450.0
5.85% senior notes due September 15, 2012	500.0	—
5.00% senior notes due December 15, 2013	500.0	500.0
5.125% senior notes due November 15, 2014	500.0	500.0
6.00% senior notes due February 1, 2017	600.0	—
7.400% senior notes due March 15, 2031	300.0	300.0
7.75% senior notes due March 15, 2032	300.0	300.0
7.30% senior notes due August 15, 2033	500.0	500.0
5.80% senior notes due March 15, 2035	500.0	500.0
6.50% senior notes due February 1, 2037	400.0	—
6.95% senior notes due January 15, 2038	550.0	—
Commercial paper borrowings	589.1	1,098.2
Subsidiary borrowings:		
Central Florida Pipe Line LLC-7.840% senior notes due July 23, 2008	5.0	10.0
Arrow Terminals L.P.-IL Development Revenue Bonds due January 1, 2010	5.3	5.3
Kinder Morgan Operating L.P. "A"-5.40% BP note, due March 31, 2012	23.6	—
Kinder Morgan Canada Company-5.40% BP note, due March 31, 2012	21.0	—
Kinder Morgan Texas Pipeline, L.P.-5.23% Senior Notes, due January 2, 2014	43.2	49.1
Kinder Morgan Liquids Terminals LLC-N.J. Development Revenue Bonds due Jan. 15, 2018	25.0	25.0
Kinder Morgan Operating L.P. "B"-Jackson-Union Cos. IL Revenue Bonds due April 1, 2024	23.7	23.7
International Marine Terminals-Plaquemines, LA Revenue Bonds due March 15, 2025	40.0	40.0
Other miscellaneous subsidiary debt	1.4	1.4
Unamortized debt discount on senior notes	(11.2)	(9.3)
Current portion of long-term debt	(610.2)	(1,359.1)
Total Long-term debt	$ 6,455.9	$ 4,384.3

Senior Notes

During 2007, we completed three separate public offerings of senior notes, and on August 15, 2007, we repaid $250 million of 5.35% senior notes that matured on that date. With regard to the three offerings, we received proceeds, net of underwriting discounts and commissions, as follows:

- $992.8 million from a January 30, 2007 public offering of a total of $1.0 billion in principal amount of senior notes, consisting of $600 million of 6.00% notes due February 1, 2017, and $400 million of 6.50% notes due February 1, 2037;
- $543.9 million from a June 21, 2007 public offering of $550 million in principal amount of 6.95% senior notes due January 15, 2038; and
- $497.8 million from an August 28, 2007 public offering of $500 million in principal amount of 5.85% senior notes due September 15, 2012.

We used the proceeds from each of these offerings to reduce the borrowings under our commercial paper program. As of December 31, 2007 and 2006, the outstanding balance on the various series of our senior notes (excluding unamortized debt discount) was $6,288.8 million and $4,490.7 million, respectively. For a listing of the various outstanding series of our senior notes, see the table above included in "—Long-Term Debt."

On February 12, 2008, we completed an additional public offering of senior notes. We issued a total of $900 million in principal amount of senior notes, consisting of $600 million of 5.95% notes due February 15, 2018, and

$300 million of 6.95% notes due January 15, 2038. We received proceeds from the issuance of the notes, after underwriting discounts and commissions, of approximately $894.1 million, and we used the proceeds to reduce the borrowings under our commercial paper program. The notes due in 2038 constitute a further issuance of the $550 million aggregate principal amount of 6.95% notes issued on June 21, 2007 (referred to above) and will form a single series with those notes.

Interest Rate Swaps

Information on our interest rate swaps is contained in Note 14.

Subsidiary Debt

Our subsidiaries are obligors on the following debt. The agreements governing these obligations contain various affirmative and negative covenants and events of default. We do not believe that these provisions will materially affect distributions to our partners.

Central Florida Pipeline LLC Debt

Central Florida Pipeline LLC is an obligor on an aggregate principal amount of $40 million of senior notes originally issued to a syndicate of eight insurance companies. The senior notes have a fixed annual interest rate of 7.84% with repayments in annual installments of $5 million beginning July 23, 2001. The final payment is due July 23, 2008. Interest is payable semiannually on January 1 and July 23 of each year. In both July 2007 and July 2006, we made an annual repayment of $5.0 million and as of December 31, 2007, Central Florida's outstanding balance under the senior notes was $5.0 million.

Arrow Terminals L.P.

Arrow Terminals L.P. is an obligor on a $5.3 million principal amount of Adjustable Rate Industrial Development Revenue Bonds issued by the Illinois Development Finance Authority. The bonds have a maturity date of January 1, 2010, and interest on these bonds is paid and computed quarterly at the Bond Market Association Municipal Swap Index. The bonds are collateralized by a first mortgage on assets of Arrow's Chicago operations and a third mortgage on assets of Arrow's Pennsylvania operations. As of December 31, 2007, the interest rate was 3.595%. The bonds are also backed by a $5.4 million letter of credit issued by JP Morgan Chase that backs-up the $5.3 million principal amount of the bonds and $0.1 million of interest on the bonds for up to 45 days computed at 12% per annum on the principal amount thereof.

Kinder Morgan Texas Pipeline, L.P. Debt

Kinder Morgan Texas Pipeline, L.P. is the obligor on a series of unsecured senior notes with a fixed annual stated interest rate as of August 1, 2005, of 8.85%. The assumed principal amount, along with interest, is due in monthly installments of approximately $0.7 million. The final payment is due January 2, 2014. As of December 31, 2007, KMTP's outstanding balance under the senior notes was $43.2 million.

Additionally, the unsecured senior notes may be prepaid at any time in amounts of at least $1.0 million and at a price equal to the higher of par value or the present value of the remaining scheduled payments of principal and interest on the portion being prepaid.

Kinder Morgan Liquids Terminals LLC Debt

Kinder Morgan Liquids Terminals LLC is the obligor on $25.0 million of Economic Development Revenue Refunding Bonds issued by the New Jersey Economic Development Authority. These bonds have a maturity date of January 15, 2018. Interest on these bonds is computed on the basis of a year of 365 or 366 days, as applicable, for the actual number of days elapsed during Commercial Paper, Daily or Weekly Rate Periods and on the basis of a 360-day year consisting of twelve 30-day months during a Term Rate Period. As of December 31, 2007, the interest rate was 3.57%. We have an outstanding letter of credit issued by Citibank in the amount of $25.3 million that backs-up the $25.0 million principal amount of the bonds and $0.3 million of interest on the bonds for up to 42 days computed at 12% on a per annum basis on the principal thereof.

Kinder Morgan Operating L.P. "B" Debt

This $23.7 million principal amount of tax-exempt bonds due April 1, 2024 was issued by the Jackson-Union Counties Regional Port District. These bonds bear interest at a weekly floating market rate. As of December 31, 2007, the interest rate on these bonds was 3.33%. Also, as of December 31, 2007, we had an outstanding letter of credit issued by Wachovia in the amount of $24.1 million that backs-up the $23.7 million principal amount of the bonds and $0.4 million of interest on the bonds for up to 55 days computed at 12% per annum on the principal amount thereof.

International Marine Terminals Debt

We own a 66 2/3% interest in International Marine Terminals partnership. The principal assets owned by IMT are dock and wharf facilities financed by the Plaquemines Port, Harbor and Terminal District (Louisiana) $40.0 million Adjustable Rate Annual Tender Port Facilities Revenue Refunding Bonds (International Marine Terminals Project) Series 1984A and 1984B. As of December 31, 2007, the interest rate on these bonds was 3.65%.

On March 15, 2005, these bonds were refunded and the maturity date was extended from March 15, 2006 to March 15, 2025. No other changes were made under the bond provisions. The bonds are backed by two letters of credit issued by KBC Bank N.V. On March 19, 2002, an Amended and Restated Letter of Credit Reimbursement Agreement relating to the letters of credit in the amount of $45.5 million was entered into by IMT and KBC Bank. In connection with that agreement, we agreed to guarantee the obligations of IMT in proportion to our ownership interest. Our obligation is approximately $30.3 million for principal, plus interest and other fees.

Kinder Morgan Operating L.P. "A" Debt

Effective January 1, 2007, we acquired the remaining approximate 50.2% interest in the Cochin pipeline system that we did not already own (see Note 3). As part of our purchase price, two of our subsidiaries issued a long-term note payable to the seller having a fair value of $42.3 million. We valued the debt equal to the present value of amounts to be paid, determined using an annual interest rate of 5.40%. The principal amount of the note, along with interest, is due in five annual installments of $10.0 million beginning March 31, 2008. The final payment is due March 31, 2012. Our subsidiaries Kinder Morgan Operating L.P. "A" and Kinder Morgan Canada Company are the obligors on the note, and as of December 31, 2007, the outstanding balance under the note was $44.6 million.

Maturities of Debt

The scheduled maturities of our outstanding debt, excluding value of interest rate swaps, as of December 31, 2007, are summarized as follows (in millions):

Year	Commitment
2008	$ 610.2
2009	265.8
2010	270.7
2011	715.1
2012	964.3
Thereafter	4,240.0
Total	$ 7,066.1

Contingent Debt

As prescribed by the provisions of Financial Accounting Standards Board Interpretation (FIN) No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others," we disclose certain types of guarantees or indemnifications we have made. These disclosures cover certain types of guarantees included within debt agreements, even if the likelihood of requiring our performance under such guarantee is remote. The following is a description of our contingent debt agreements as of December 31, 2007.

Cortez Pipeline Company Debt

Pursuant to a certain Throughput and Deficiency Agreement, the partners of Cortez Pipeline Company (Kinder Morgan CO_2 Company, L.P. – 50% partner; a subsidiary of Exxon Mobil Corporation – 37% partner; and Cortez Vickers Pipeline Company – 13% partner) are required, on a several, proportional percentage ownership basis, to contribute capital to Cortez Pipeline Company in the event of a cash deficiency. Furthermore, due to our indirect ownership of Cortez Pipeline Company through Kinder Morgan CO_2 Company, L.P., we severally guarantee 50% of the debt of Cortez Capital Corporation, a wholly-owned subsidiary of Cortez Pipeline Company.

As of December 31, 2007, the debt facilities of Cortez Capital Corporation consisted of (i) $64.3 million of Series D notes due May 15, 2013; (ii) a $125 million short-term commercial paper program; and (iii) a $125 million five-year committed revolving credit facility due December 22, 2009 (to support the above-mentioned $125 million commercial paper program). As of December 31, 2007, Cortez Capital Corporation had $93.0 million of commercial paper outstanding with an average interest rate of approximately 5.66%, the average interest rate on the Series D notes was 7.14%, and there were no borrowings under the credit facility.

With respect to Cortez's Series D notes, Shell Oil Company shares our several guaranty obligations jointly and severally; however, we are obligated to indemnify Shell for liabilities it incurs in connection with such guaranty and JP Morgan Chase issued a letter of credit on our behalf in December 2006 in the amount of $37.5 million to secure our indemnification obligations to Shell for 50% of the $75 million in principal amount of Series D notes outstanding as of December 31, 2006.

Red Cedar Gathering Company Debt

Red Cedar Gathering Company was the obligor on $55 million in aggregate principal amount of Senior Notes due October 31, 2010. The Senior Notes were collateralized by a first priority lien on the ownership interests, including our 49% ownership interest, in Red Cedar Gathering Company. The Senior Notes were also guaranteed by us and the other owner of Red Cedar Gathering Company jointly and severally. As of December 31, 2006, $31.4 million in principal amount of notes were outstanding.

In March 2007, Red Cedar refinanced the outstanding balance of its existing Senior Notes through a private placement of $100 million in principal amount of ten year fixed rate notes. As a result of Red Cedar Gathering Company's retirement of the remaining $31.4 million outstanding principal amount of its Senior Notes, we are no longer contingently liable for any Red Cedar Gathering Company debt.

Nassau County, Florida Ocean Highway and Port Authority Debt

We have posted a letter of credit as security for borrowings under Adjustable Demand Revenue Bonds issued by the Nassau County, Florida Ocean Highway and Port Authority. The bonds were issued for the purpose of constructing certain port improvements located in Fernandino Beach, Nassau County, Florida. Our subsidiary, Nassau Terminals LLC is the operator of the marine port facilities.

The bond indenture is for 30 years and allows the bonds to remain outstanding until December 1, 2020. Principal payments on the bonds are made on the first of December each year and corresponding reductions are made to the letter of credit. As of December 31, 2007, this letter of credit had a face amount of $22.5 million.

Rockies Express Pipeline LLC Debt

Pursuant to certain guaranty agreements, all three member owners of West2East Pipeline LLC (which owns all of the member interests in Rockies Express Pipeline LLC) have agreed to guarantee, severally in the same proportion as their percentage ownership of the member interests in West2East Pipeline LLC, borrowings under Rockies Express' (i) $2.0 billion five-year, unsecured revolving credit facility due April 28, 2011; (ii) $2.0 billion commercial paper program; and (iii) $600 million in principal amount of floating rate senior notes due August 20,

2009. The three member owners and their respective ownership interests consist of the following: our subsidiary Kinder Morgan W2E Pipeline LLC – 51%, a subsidiary of Sempra Energy – 25%, and a subsidiary of ConocoPhillips – 24%.

Borrowings under the Rockies Express commercial paper program are primarily used to finance the construction of the Rockies Express interstate natural gas pipeline and to pay related expenses. The credit facility, which can be amended to allow for borrowings up to $2.5 billion, supports borrowings under the commercial paper program, and borrowings under the commercial paper program reduce the borrowings allowed under the credit facility.

On September 20, 2007, Rockies Express issued $600 million in principal amount of senior unsecured floating rate notes. The notes have a maturity date of August 20, 2009, and interest on these notes is paid and computed quarterly on an interest rate of three-month LIBOR plus a spread. Upon issuance of the notes, Rockies Express entered into two floating-to-fixed interest rate swap agreements having a combined notional principal amount of $600 million and a maturity date of August 20, 2009.

In addition to the $600 million in senior notes, as of December 31, 2007, Rockies Express Pipeline LLC had $1,625.4 million of commercial paper outstanding with a weighted average interest rate of approximately 5.50%, and there were no borrowings under its five-year credit facility. Accordingly, as of December 31, 2007, our contingent share of Rockies Express' debt was $1,135.0 million (51% of total borrowings).

Fair Value of Financial Instruments

Fair value as used in SFAS No. 107, "Disclosures About Fair Value of Financial Instruments," represents the amount at which an instrument could be exchanged in a current transaction between willing parties. The estimated fair value of our long-term debt, including its current portion and excluding the value of interest rate swaps, is based upon prevailing interest rates available to us as of December 31, 2007 and December 31, 2006 and is disclosed below (in millions).

	December 31, 2007		December 31, 2006	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Total Debt	$ 7,066.1	$ 7,201.8	$ 5,743.4	$ 5,865.0

10. Pensions and Other Post-Retirement Benefits

Pension and Post-Retirement Benefit Plans

Due to our acquisition of Trans Mountain (see Note 3), Kinder Morgan Canada Inc. and Trans Mountain Pipeline Inc. (as general partner of Trans Mountain Pipeline L.P.) are sponsors of pension plans for eligible Trans Mountain employees. The plans include registered defined benefit pension plans, supplemental unfunded arrangements, which provide pension benefits in excess of statutory limits, and defined contributory plans. We also provide post-retirement benefits other than pensions for retired employees. Our combined net periodic benefit costs for these Trans Mountain pension and post-retirement benefit plans for 2007 and 2006 was approximately $3.2 million and $3.5 million, respectively, recognized ratably over each year. As of December 31, 2007, we estimate our overall net periodic pension and post-retirement benefit costs for these plans for the year 2008 will be approximately $3.1 million, although this estimate could change if there is a significant event, such as a plan amendment or a plan curtailment, which would require a remeasurement of liabilities. We expect to contribute approximately $2.6 million to these benefit plans in 2008.

Additionally, in connection with our acquisition of SFPP, L.P. and Kinder Morgan Bulk Terminals, Inc. in 1998, we acquired certain liabilities for pension and post-retirement benefits. We provide medical and life insurance benefits to current employees, their covered dependents and beneficiaries of SFPP and Kinder Morgan Bulk Terminals. We also provide the same benefits to former salaried employees of SFPP. Additionally, we will continue to fund these costs for those employees currently in the plan during their retirement years. SFPP's post-retirement benefit plan is frozen and no additional participants may join the plan. The noncontributory defined benefit pension plan covering the former employees of Kinder Morgan Bulk Terminals is the Knight Inc. Retirement

Plan. The benefits under this plan are based primarily upon years of service and final average pensionable earnings; however, benefit accruals were frozen as of December 31, 1998.

Our net periodic benefit cost for the SFPP post-retirement benefit plan were credits of $0.2 million in 2007, $0.3 million in 2006, and $0.3 million in 2005. The credits resulted in increases to income, largely due to amortizations of an actuarial gain and a negative prior service cost. As of December 31, 2007, we estimate no overall net periodic post-retirement benefit cost for the SFPP post-retirement benefit plan for the year 2008; however, this estimate could change if a future significant event would require a remeasurement of liabilities. In addition, we expect to contribute approximately $0.4 million to this post-retirement benefit plan in 2008.

On September 29, 2006, the FASB issued SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statement Nos. 87, 88, 106 and 132(R)." One of the provisions of this Statement requires an employer with publicly traded equity securities to recognize the overfunded or underfunded status of a defined benefit pension plan or post-retirement benefit plan (other than a multiemployer plan) as an asset or liability in its statement of financial position and to provide the required disclosures as of the end of the fiscal year ending after December 15, 2006. Following adoption of SFAS No. 158, entities will report as part of the net benefit liability on their balance sheets amounts that have not yet been recognized as a component of benefit expense (for example, unrecognized prior service costs or credits, net (actuarial) gain or loss, and transition obligation or asset) with a corresponding adjustment to accumulated other comprehensive income.

We adopted SFAS No. 158 on December 31, 2006, and the primary impact on us from adopting this Statement was to require us to fully recognize, in our consolidated balance sheet, both the funded status of our pension and post-retirement benefit plan obligations, and previously unrecognized prior service costs and credits and actuarial gains and losses. As of December 31, 2006, the recorded value of our pension and post-retirement benefit obligations for both the Trans Mountain pension and post-retirement benefit plans and the SFPP post-retirement benefit plan was a combined $28.4 million.

The following table discloses the incremental effect on our consolidated balance sheet of applying SFAS No. 158 on December 31, 2006 (in millions):

	Before Application	Adjustments	After Application
Prepaid benefit cost	$ —	$ —	$ —
Accrued benefit liability	30.3	(1.9)	28.4
Intangible asset	—	—	—
Deferred income tax liability	(6.4)	(1.2)	(7.6)
Minority interest	—	—	—
Accumulated other comprehensive income	—	3.1	3.1

As of December 31, 2007, the recorded value of our pension and post-retirement benefit obligations for these plans was a combined $37.5 million. We consider our overall pension and post-retirement benefit liability exposure to be minimal in relation to the value of our total consolidated assets and net income.

Multiemployer Plans

As a result of acquiring several terminal operations, primarily our acquisition of Kinder Morgan Bulk Terminals, Inc. effective July 1, 1998, we participate in several multi-employer pension plans for the benefit of employees who are union members. We do not administer these plans and contribute to them in accordance with the provisions of negotiated labor contracts. Other benefits include a self-insured health and welfare insurance plan and an employee health plan where employees may contribute for their dependents' health care costs. Amounts charged to expense for these plans were approximately $6.7 million for the year ended December 31, 2007, and $6.3 million for each of the years ended December 31, 2006 and 2005.

Kinder Morgan Savings Plan

The Kinder Morgan Savings Plan is a defined contribution 401(k) plan. The plan permits all full-time employees of Knight, Inc. and KMGP Services Company, Inc. to contribute between 1% and 50% of base compensation, on a pre-tax basis, into participant accounts. In addition to a mandatory contribution equal to 4% of base compensation per year for most plan participants, our general partner may make special discretionary contributions. Certain employees' contributions are based on collective bargaining agreements. The mandatory contributions are made each pay period on behalf of each eligible employee. Participants may direct the investment of their contributions and all employer contributions, including discretionary contributions, into a variety of investments. Plan assets are held and distributed pursuant to a trust agreement. The total amount charged to expense for our Savings Plan was $11.7 million during 2007, $10.2 million during 2006, and $7.9 million during 2005.

Employer contributions for employees vest on the second anniversary of the date of hire. Effective October 1, 2005, for new employees of our Terminals segment, a tiered employer contribution schedule was implemented. This tiered schedule provides for employer contributions of 1% for service less than one year, 2% for service between one and two years, 3% for services between two and five years, and 4% for service of five years or more. All employer contributions for Terminals employees hired after October 1, 2005 vest on the fifth anniversary of the date of hire (effective January 1, 2008, this five year anniversary date for Terminals employees was changed to three years to comply with changes in federal regulations).

At its July 2007 meeting, the compensation committee of the KMR board of directors approved a special contribution of an additional 1% of base pay into the Savings Plan for each eligible employee. Each eligible employee will receive an additional 1% company contribution based on eligible base pay each pay period beginning with the first pay period of August 2007 and continuing through the last pay period of July 2008. The additional 1% contribution does not change or otherwise impact, the annual 4% contribution that eligible employees currently receive and it will vest according to the same vesting schedule described in the preceding paragraph. Since this additional 1% company contribution is discretionary, compensation committee approval will be required annually for each additional contribution. During the first quarter of 2008, excluding the 1% additional contribution described above, we will not make any additional discretionary contributions to individual accounts for 2007.

Additionally, in 2006, an option to make after-tax "Roth" contributions (Roth 401(k) option) to a separate participant account was added to the Savings Plan as an additional benefit to all participants. Unlike traditional 401(k) plans, where participant contributions are made with pre-tax dollars, earnings grow tax-deferred, and the withdrawals are treated as taxable income, Roth 401(k) contributions are made with after-tax dollars, earnings are tax-free, and the withdrawals are tax-free if they occur after both (i) the fifth year of participation in the Roth 401(k) option, and (ii) attainment of age 59 ½, death or disability. The employer contribution will still be considered taxable income at the time of withdrawal.

Cash Balance Retirement Plan

Employees of KMGP Services Company, Inc. and Knight are also eligible to participate in a Cash Balance Retirement Plan. Certain employees continue to accrue benefits through a career-pay formula, "grandfathered" according to age and years of service on December 31, 2000, or collective bargaining arrangements. All other employees accrue benefits through a personal retirement account in the Cash Balance Retirement Plan. Under the plan, we make contributions on behalf of participating employees equal to 3% of eligible compensation every pay period. Interest is credited to the personal retirement accounts at the 30-year U.S. Treasury bond rate, or an approved substitute, in effect each year. Employees become fully vested in the plan after five years, and they may take a lump sum distribution upon termination of employment or retirement.

11. Partners' Capital

Limited Partner Units

As of December 31, 2007 and 2006, our partners' capital consisted of the following limited partner units:

	December 31, 2007	December 31, 2006
Common units	170,220,396	162,816,303
Class B units	5,313,400	5,313,400
i-units	72,432,482	62,301,676
Total limited partner units	247,966,278	230,431,379

The total limited partner units represent our limited partners' interest and an effective 98% economic interest in us, exclusive of our general partner's incentive distribution rights. Our general partner has an effective 2% interest in us, excluding its incentive distribution rights.

As of December 31, 2007, our common unit total consisted of 155,864,661 units held by third parties, 12,631,735 units held by Knight and its consolidated affiliates (excluding our general partner) and 1,724,000 units held by our general partner. As of December 31, 2006, our common unit total consisted of 148,460,568 units held by third parties, 12,631,735 units held by Knight and its consolidated affiliates (excluding our general partner) and 1,724,000 units held by our general partner.

On both December 31, 2007 and December 31, 2006, all of our 5,313,400 Class B units were held entirely by a wholly-owned subsidiary of Knight. The Class B units are similar to our common units except that they are not eligible for trading on the New York Stock Exchange. All of our Class B units were issued to a wholly-owned subsidiary of Knight in December 2000.

On both December 31, 2007 and December 31, 2006, all of our i-units were held entirely by KMR. Our i-units are a separate class of limited partner interests in us and are not publicly traded. In accordance with its limited liability company agreement, KMR's activities are restricted to being a limited partner in us, and to controlling and managing our business and affairs and the business and affairs of our operating limited partnerships and their subsidiaries. Through the combined effect of the provisions in our partnership agreement and the provisions of KMR's limited liability company agreement, the number of outstanding KMR shares and the number of i-units will at all times be equal.

Under the terms of our partnership agreement, we agreed that we will not, except in liquidation, make a distribution on an i-unit other than in additional i-units or a security that has in all material respects the same rights and privileges as our i-units. The number of i-units we distribute to KMR is based upon the amount of cash we distribute to the owners of our common units. When cash is paid to the holders of our common units, we will issue additional i-units to KMR. The fraction of an i-unit paid per i-unit owned by KMR will have a value based on the cash payment on the common unit.

The cash equivalent of distributions of i-units will be treated as if it had actually been distributed for purposes of determining the distributions to our general partner. We will not distribute the cash to the holders of our i-units but will instead retain the cash for use in our business. If additional units are distributed to the holders of our common units, we will issue an equivalent amount of i-units to KMR based on the number of i-units it owns. Based on the preceding, KMR received a distribution of 1,258,778 i-units on November 14, 2007. These additional i-units distributed were based on the $0.88 per unit distributed to our common unitholders on that date. During the year ended December 31, 2007, KMR received distributions of 4,430,806 i-units. These additional i-units distributed were based on the $3.39 per unit distributed to our common unitholders during 2007. During 2006, KMR received distributions of 4,383,303 i-units, based on the $3.23 per unit distributed to our common unitholders during 2006.

Equity Issuances

In August 2006, we issued, in a public offering, 5,750,000 of our common units, including common units sold pursuant to the underwriters' over-allotment option, at a price of $44.80 per unit, less commissions and underwriting expenses. We received net proceeds of approximately $248.0 million for the issuance of these 5,750,000 common units.

On May 17, 2007, KMR issued 5,700,000 of its shares in a public offering at a price of $52.26 per share. The net proceeds from the offering were used by KMR to buy additional i-units from us, and we received net proceeds of $297.9 million for the issuance of 5,700,000 i-units.

On December 5, 2007, we issued, in a public offering, 7,130,000 of our common units, including common units sold pursuant to the underwriters' over-allotment option, at a price of $48.09 per unit, less commissions and underwriting expenses. We received net proceeds of $342.9 million for the issuance of these 7,130,000 common units.

We used the proceeds from each of these three issuances to reduce the borrowings under our commercial paper program. In addition, pursuant to our purchase and sale agreement with Trans-Global Solutions, Inc., we issued 266,813 common units in May 2007 to TGS to settle a purchase price liability related to our acquisition of bulk terminal operations from TGS in April 2005. As agreed between TGS and us, the units were issued equal to a value of $15.0 million.

In addition, on February 12, 2008, we completed an offering of 1,080,000 of our common units at a price of $55.65 per unit in a privately negotiated transaction. We received net proceeds of $60.1 million for the issuance of these 1,080,000 common units, and we used the proceeds to reduce the borrowings under our commercial paper program.

Income Allocation and Declared Distributions

For the purposes of maintaining partner capital accounts, our partnership agreement specifies that items of income and loss shall be allocated among the partners, other than owners of i-units, in accordance with their percentage interests. Normal allocations according to percentage interests are made, however, only after giving effect to any priority income allocations in an amount equal to the incentive distributions that are allocated 100% to our general partner. Incentive distributions are generally defined as all cash distributions paid to our general partner that are in excess of 2% of the aggregate value of cash and i-units being distributed.

Incentive distributions allocated to our general partner are determined by the amount quarterly distributions to unitholders exceed certain specified target levels, according to the provisions of our partnership agreement. For the years ended December 31, 2007, 2006 and 2005, we declared distributions of $3.48, $3.26 and $3.13 per unit, respectively. Under the terms of our partnership agreement, our total distributions to unitholders for 2007, 2006 and 2005 required incentive distributions to our general partner in the amount of $611.9 million, $528.4 million and $473.9 million, respectively. The increased incentive distributions paid for 2007 over 2006, and 2006 over 2005 reflect the increases in amounts distributed per unit as well as the issuance of additional units. Distributions for the fourth quarter of each year are declared and paid during the first quarter of the following year.

Fourth Quarter 2006 Incentive Distribution Waiver

According to the provisions of the Knight Annual Incentive Plan, in order for the executive officers of our general partner and KMR, and for the employees of KMGP Services Company, Inc. and Knight who operate our business to earn a non-equity cash incentive (bonus) for 2006, both we and Knight were required to meet pre-established financial performance targets. The target for us was $3.28 in cash distributions per common unit for 2006. Due to the fact that we did not meet our 2006 budget target, we had no obligation to fund our 2006 bonus plan; however, at its January 17, 2007 board meeting, the board of directors of KMI (now Knight) determined that it was in KMI's long-term interest to fund a partial payout of our bonuses through a reduction in our general partner's incentive distribution.

Accordingly, our general partner, with the approval of the compensation committees and boards of KMI and KMR, waived $20.1 million of its 2006 incentive distribution for the fourth quarter of 2006. The waived amount approximated an amount equal to our actual bonus payout for 2006, which was approximately 75% of our budgeted full bonus payout for 2006 of $26.5 million. Including the effect of this waiver, our distributions to unitholders for

2006 resulted in payments of incentive distributions to our general partner in the amount of $508.3 million. The waiver of $20.1 million of incentive payment in the fourth quarter of 2006 reduced our general partner's equity earnings by $19.9 million.

Fourth Quarter 2007 Incentive Distribution

On January 16, 2008, we declared a cash distribution of $0.92 per unit for the quarterly period ended December 31, 2007. This distribution was paid on February 14, 2008, to unitholders of record as of January 31, 2008. Our common unitholders and Class B unitholders received cash. KMR, our sole i-unitholder, received a distribution in the form of additional i-units based on the $0.92 distribution per common unit. The number of i-units distributed was 1,253,951. For each outstanding i-unit that KMR held, a fraction of an i-unit (0.017312) was issued. The fraction was determined by dividing:

- $0.92, the cash amount distributed per common unit

by

- $53.143, the average of KMR's limited liability shares' closing market prices from January 14-28, 2008, the ten consecutive trading days preceding the date on which the shares began to trade ex-dividend under the rules of the New York Stock Exchange.

This February 14, 2008 distribution included an incentive distribution to our general partner in the amount of $170.3 million. Since this distribution was declared after the end of the quarter, no amount is shown in our December 31, 2007 balance sheet as a distribution payable.

12. Related Party Transactions

General and Administrative Expenses

KMGP Services Company, Inc., a subsidiary of our general partner, provides employees and Kinder Morgan Services LLC, a wholly owned subsidiary of KMR, provides centralized payroll and employee benefits services to (i) us; (ii) our operating partnerships and subsidiaries; (iii) our general partner; and (iv) KMR (collectively, the "Group"). Employees of KMGP Services Company, Inc. are assigned to work for one or more members of the Group. The direct costs of all compensation, benefits expenses, employer taxes and other employer expenses for these employees are allocated and charged by Kinder Morgan Services LLC to the appropriate members of the Group, and the members of the Group reimburse Kinder Morgan Services LLC for their allocated shares of these direct costs. There is no profit or margin charged by Kinder Morgan Services LLC to the members of the Group. The administrative support necessary to implement these payroll and benefits services is provided by the human resource department of Knight, and the related administrative costs are allocated to members of the Group in accordance with existing expense allocation procedures. The effect of these arrangements is that each member of the Group bears the direct compensation and employee benefits costs of its assigned or partially assigned employees, as the case may be, while also bearing its allocable share of administrative costs. Pursuant to our limited partnership agreement, we provide reimbursement for our share of these administrative costs and such reimbursements will be accounted for as described above. Additionally, we reimburse KMR with respect to costs incurred or allocated to KMR in accordance with our limited partnership agreement, the delegation of control agreement among our general partner, KMR, us and others, and KMR's limited liability company agreement.

The named executive officers of our general partner and KMR and other employees that provide management or services to both Knight and the Group are employed by Knight. Additionally, other Knight employees assist in the operation of our Natural Gas Pipeline assets. These Knight employees' expenses are allocated without a profit component between Knight and the appropriate members of the Group.

Additionally, in accordance with SFAS No. 123R, Knight Holdco LLC is required to recognize compensation expense in connection with their Class A-1 and Class B units over the expected life of such units. As a subsidiary of Knight Holdco LLC, we are allocated a portion of this compensation expense, although we have no obligation nor do we expect to pay any of these costs.

Partnership Interests and Distributions

Kinder Morgan G.P., Inc.

Kinder Morgan G.P., Inc. serves as our sole general partner. Pursuant to our partnership agreement, our general partner's interests represent a 1% ownership interest in us, and a direct 1.0101% ownership interest in each of our five operating partnerships. Collectively, our general partner owns an effective 2% interest in our operating partnerships, excluding incentive distributions rights as follows:

- its 1.0101% direct general partner ownership interest (accounted for as minority interest in our consolidated financial statements); and
- its 0.9899% ownership interest indirectly owned via its 1% ownership interest in us.

As of December 31, 2007, our general partner owned 1,724,000 common units, representing approximately 0.70% of our outstanding limited partner units.

Our partnership agreement requires that we distribute 100% of "Available Cash," as defined in our partnership agreement, to our partners within 45 days following the end of each calendar quarter in accordance with their respective percentage interests. Available Cash consists generally of all of our cash receipts, including cash received by our operating partnerships and net reductions in reserves, less cash disbursements and net additions to reserves and amounts payable to the former general partner of SFPP, L.P. in respect of its remaining 0.5% interest in SFPP.

Our general partner is granted discretion by our partnership agreement, which discretion has been delegated to KMR, subject to the approval of our general partner in certain cases, to establish, maintain and adjust reserves for future operating expenses, debt service, maintenance capital expenditures, rate refunds and distributions for the next four quarters. These reserves are not restricted by magnitude, but only by type of future cash requirements with which they can be associated. When KMR determines our quarterly distributions, it considers current and expected reserve needs along with current and expected cash flows to identify the appropriate sustainable distribution level.

Our general partner and owners of our common units and Class B units receive distributions in cash, while KMR, the sole owner of our i-units, receives distributions in additional i-units. We do not distribute cash to i-unit owners but retain the cash for use in our business. However, the cash equivalent of distributions of i-units is treated as if it had actually been distributed for purposes of determining the distributions to our general partner. Each time we make a distribution, the number of i-units owned by KMR and the percentage of our total units owned by KMR increase automatically under the provisions of our partnership agreement.

Available cash is initially distributed 98% to our limited partners and 2% to our general partner. These distribution percentages are modified to provide for incentive distributions to be paid to our general partner in the event that quarterly distributions to unitholders exceed certain specified targets.

Available cash for each quarter is distributed:

- first, 98% to the owners of all classes of units pro rata and 2% to our general partner until the owners of all classes of units have received a total of $0.15125 per unit in cash or equivalent i-units for such quarter;
- second, 85% of any available cash then remaining to the owners of all classes of units pro rata and 15% to our general partner until the owners of all classes of units have received a total of $0.17875 per unit in cash or equivalent i-units for such quarter;
- third, 75% of any available cash then remaining to the owners of all classes of units pro rata and 25% to our general partner until the owners of all classes of units have received a total of $0.23375 per unit in cash or equivalent i-units for such quarter; and

- fourth, 50% of any available cash then remaining to the owners of all classes of units pro rata, to owners of common units and Class B units in cash and to owners of i-units in the equivalent number of i-units, and 50% to our general partner.

For more information on incentive distributions paid to our general partner, see Note 11 "—Income Allocation and Declared Distributions."

Knight Inc.

Knight Inc. remains the sole indirect stockholder of our general partner. Also, as of December 31, 2007, Knight directly owned 8,838,095 common units, indirectly owned 5,313,400 Class B units and 5,517,640 common units through its consolidated affiliates, including our general partner, and owned 10,334,746 KMR shares, representing an indirect ownership interest of 10,334,746 i-units. Together, these units represented approximately 12.1% of our outstanding limited partner units. Including both its general and limited partner interests in us, at the 2007 distribution level, Knight received approximately 49% of all quarterly distributions from us, of which approximately 43% was attributable to its general partner interest and the remaining 6% was attributable to its limited partner interest. The actual level of distributions Knight will receive in the future will vary with the level of distributions to our limited partners determined in accordance with our partnership agreement.

Kinder Morgan Management, LLC

As of December 31, 2007, KMR, our general partner's delegate, remained the sole owner of our 72,432,482 i-units.

Asset Acquisitions and Sales

From time to time in the ordinary course of business, we buy and sell pipeline and related services from Knight and its subsidiaries. Such transactions are conducted in accordance with all applicable laws and regulations and on an arms' length basis consistent with our policies governing such transactions. In conjunction with our acquisition of (i) certain Natural Gas Pipelines assets and partnership interests from Knight in December 1999 and December 2000; and (ii) all of the ownership interest in TransColorado Gas Transmission Company LLC from two wholly-owned subsidiaries of Knight on November 1, 2004, Knight agreed to indemnify us and our general partner with respect to approximately $733.5 million of our debt. Knight would be obligated to perform under this indemnity only if we are unable, and/or our assets were insufficient to satisfy our obligations.

Operations

Natural Gas Pipelines Business Segment

Knight or its subsidiaries operate and maintain for us the assets comprising our Natural Gas Pipelines business segment. Natural Gas Pipeline Company of America, a subsidiary of Knight, operates Trailblazer Pipeline Company LLC's assets under a long-term contract pursuant to which Trailblazer Pipeline Company LLC incurs the costs and expenses related to NGPL's operating and maintaining the assets. Trailblazer Pipeline Company LLC provides the funds for its own capital expenditures. NGPL does not profit from or suffer loss related to its operation of Trailblazer Pipeline Company LLC's assets.

The remaining assets comprising our Natural Gas Pipelines business segment as well as our Cypress Pipeline (and our North System until its sale in October 2007, described in Note 3), which is part of our Products Pipelines business segment, are operated under other agreements between Knight and us. Pursuant to the applicable underlying agreements, we pay Knight either a fixed amount or actual costs incurred as reimbursement for the corporate general and administrative expenses incurred in connection with the operation of these assets. The amounts paid to Knight for corporate general and administrative costs, including amounts related to Trailblazer Pipeline Company LLC, were $1.0 million of fixed costs and $48.1 million of actual costs incurred for 2007, $1.0 million of fixed costs and $37.9 million of actual costs incurred for 2006, and $5.5 million of fixed costs and $24.2 million of actual costs incurred for 2005.

We believe the amounts paid to Knight for the services they provided each year fairly reflect the value of the services performed. However, due to the nature of the allocations, these reimbursements may not exactly match the actual time and overhead spent. We believe the fixed amounts that were agreed upon at the time the contracts were entered into were reasonable estimates of the corporate general and administrative expenses to be incurred by Knight and its subsidiaries in performing such services. We also reimburse Knight and its subsidiaries for operating and maintenance costs and capital expenditures incurred with respect to our assets.

CO_2 Business Segment

Knight or its subsidiaries operate and maintain for us the power plant we constructed at the SACROC oil field unit, located in the Permian Basin area of West Texas. The power plant provides approximately half of SACROC's current electricity needs. Kinder Morgan Power Company, a subsidiary of Knight, operates and maintains the power plant under a five-year contract expiring in June 2010. Pursuant to the contract, Knight incurs the costs and expenses related to operating and maintaining the power plant for the production of electrical energy at the SACROC field. Such costs include supervisory personnel and qualified operating and maintenance personnel in sufficient numbers to accomplish the services provided in accordance with good engineering, operating and maintenance practices. Kinder Morgan Production Company fully reimburses Knight's expenses, including all agreed-upon labor costs, and also pays to Knight an operating fee of $20,000 per month.

In addition, Kinder Morgan Production Company is responsible for processing and directly paying invoices for fuels utilized by the plant. Other materials, including but not limited to lubrication oil, hydraulic oils, chemicals, ammonia and any catalyst are purchased by Knight and invoiced monthly as provided by the contract, if not paid directly by Kinder Morgan Production Company. The amounts paid to Knight in 2007 and 2006 for operating and maintaining the power plant were $3.1 million and $2.9 million, respectively. Furthermore, we believe the amounts paid to Knight for the services they provide each year fairly reflect the value of the services performed.

Risk Management

Certain of our business activities expose us to risks associated with changes in the market price of natural gas, natural gas liquids and crude oil. We also have exposure to interest rate risk as a result of the issuance of our fixed rate debt obligations. Pursuant to our management's approved risk management policy, we use derivative contracts to hedge or reduce our exposure to these risks and protect our profit margins, and we are prohibited from engaging in speculative trading.

Our commodity-related risk management activities are monitored by our risk management committee, which is a separately designated standing committee whose job responsibilities involve operations exposed to commodity market risk and other external risks in the ordinary course of business. Our risk management committee is charged with the review and enforcement of our management's risk management policy. The committee is comprised of 19 executive-level employees of Knight or KMGP Services Company, Inc. whose job responsibilities involve operations exposed to commodity market risk and other external risks in the ordinary course of our businesses. The committee is chaired by our President and is charged with the following three responsibilities: (i) establish and review risk limits consistent with our risk tolerance philosophy; (ii) recommend to the audit committee of our general partner's delegate any changes, modifications, or amendments to our risk management policy; and (iii) address and resolve any other high-level risk management issues.

In addition, as discussed in Note 1, as a result of the going private transaction of Knight, a number of individuals and entities became significant investors in Knight. By virtue of the size of their ownership interest in Knight, two of those investors became "related parties" to us (as that term is defined in authoritative accounting literature): (i) American International Group, Inc. and certain of its affiliates; and (ii) Goldman Sachs Capital Partners and certain of its affiliates. We and/or our affiliates enter into transactions with certain AIG affiliates in the ordinary course of their conducting insurance and insurance-related activities, although no individual transaction is, and all such transactions collectively are not, material to our consolidated financial statements.

We also conduct commodity risk management activities in the ordinary course of implementing our risk management strategies in which the counterparty to certain of our derivative transactions is an affiliate of Goldman Sachs. In conjunction with these activities, we are a party (through one of our subsidiaries engaged in the production of crude oil) to a hedging facility with J. Aron & Company/Goldman Sachs which requires us to provide certain periodic information, but does not require the posting of margin. As a result of changes in the market value of our derivative positions, we have created both amounts receivable from and payable to Goldman Sachs affiliates.

The following table summarizes the fair values of these energy commodity derivative contracts associated with our commodity price risk management activities with related parties and included on our accompanying consolidated balance sheets as of December 31, 2007 (in millions):

Derivatives-net asset/(liability)	
Accrued other current liabilities	$ (239.8)
Other long-term liabilities and deferred credits	$ (386.5)

For more information on our risk management activities see Note 14.

KM Insurance, Ltd.

KM Insurance, Ltd., referred to as KMIL, is a Bermuda insurance company and wholly-owned subsidiary of Knight. KMIL was formed during the second quarter of 2005 as a Class 2 Bermuda insurance company, the sole business of which is to issue policies for Knight and us to secure the deductible portion of our workers compensation, automobile liability, and general liability policies placed in the commercial insurance market. We accrue for the cost of insurance, which is included in the related party general and administrative expenses and which totaled approximately $3.6 million in 2007 and $5.8 million in 2006.

Notes Receivable

Plantation Pipe Line Company

We have a seven-year note receivable bearing interest at the rate of 4.72% per annum from Plantation Pipe Line Company, our 51.17%-owned equity investee. The outstanding note receivable balance was $89.7 million and $93.1 million as of December 31, 2007 and December 31, 2006, respectively. Of these amounts, $2.4 million and $3.4 million were included within "Accounts, notes and interest receivable, net—Related parties" as of December 31, 2007 and December 31, 2006, respectively, and the remainder was included within "Notes receivable—Related parties" at each reporting date.

Knight Inc.

As of December 31, 2007, an affiliate of Knight owed to us a long-term note with a principal amount of $0.6 million, and we included this balance within "Notes receivable—Related parties" on our consolidated balance sheet as of that date. This note currently has no fixed terms of repayment and is denominated in Canadian dollars. As of December 31, 2006, we had an additional note receivable denominated in Canadian dollars from a second affiliate of Knight (and which became an affiliate of ours in 2007), and combined, the two notes had a translated principal amount of $6.5 million. The above amounts represent the translated amounts included in our consolidated financial statements in U.S. dollars.

Additionally, prior to our acquisition of Trans Mountain on April 30, 2007, Knight and certain of its affiliates advanced cash to Trans Mountain. The advances were primarily used by Trans Mountain for capital expansion projects. Knight and its affiliates also funded Trans Mountain's cash book overdrafts (outstanding checks) as of April 30, 2007. Combined, the funding for these items totaled $67.5 million, and we reported this amount within the caption "Changes in components of working capital: Accounts Receivable" in the operating section of our accompanying consolidated statement of cash flows.

Coyote Gas Treating, LLC

Coyote Gas Treating, LLC is a joint venture that was organized in December 1996. It is referred to as Coyote Gulch in this report. The sole asset owned by Coyote Gulch is a 250 million cubic feet per day natural gas treating facility located in La Plata County, Colorado. Prior to the contribution of our ownership interest in Coyote Gulch to

Red Cedar Gathering on September 1, 2006, we were the managing partner and owned a 50% equity interest in Coyote Gulch.

As of January 1, 2006, we had a $17.0 million note receivable from Coyote Gulch. The term of the note was month-to-month. In March 2006, the owners of Coyote Gulch agreed to transfer Coyote Gulch's notes payable to members' equity. Accordingly, we contributed the principal amount of $17.0 million related to our note receivable to our equity investment in Coyote Gulch.

On September 1, 2006, we and the Southern Ute Tribe (owners of the remaining 50% interest in Coyote Gulch) agreed to transfer all of the members' equity in Coyote Gulch to the members' equity of Red Cedar Gathering Company, a joint venture organized in August 1994. Red Cedar owns and operates natural gas gathering, compression and treating facilities in the Ignacio Blanco Field in La Plata County, Colorado, and is owned 49% by us and 51% by the Southern Ute Tribe. Under the terms of a five-year operating lease agreement that became effective January 1, 2002, Red Cedar also operates the gas treating facility owned by Coyote Gulch and is responsible for all operating and maintenance expenses and capital costs.

Accordingly, on September 1, 2006, we and the Southern Ute Tribe contributed the value of our respective 50% ownership interests in Coyote Gulch to Red Cedar, and as a result, Coyote Gulch became a wholly owned subsidiary of Red Cedar. The value of our 50% equity contribution from Coyote Gulch to Red Cedar on September 1, 2006 was $16.7 million, and this amount remains included within "Investments" on our consolidated balance sheet as of December 31, 2007.

Other

Generally, KMR makes all decisions relating to the management and control of our business. Our general partner owns all of KMR's voting securities and is its sole managing member. Knight, through its wholly owned and controlled subsidiary Kinder Morgan (Delaware), Inc., owns all the common stock of our general partner. Certain conflicts of interest could arise as a result of the relationships among KMR, our general partner, Knight and us. The officers of Knight have fiduciary duties to manage Knight, including selection and management of its investments in its subsidiaries and affiliates, in a manner beneficial to themselves. In general, KMR has a fiduciary duty to manage us in a manner beneficial to our unitholders. The partnership agreements for us and our operating partnerships contain provisions that allow KMR to take into account the interests of parties in addition to us in resolving conflicts of interest, thereby limiting its fiduciary duty to our unitholders, as well as provisions that may restrict the remedies available to our unitholders for actions taken that might, without such limitations, constitute breaches of fiduciary duty.

The partnership agreements provide that in the absence of bad faith by KMR, the resolution of a conflict by KMR will not be a breach of any duties. The duty of the officers of Knight may, therefore, come into conflict with the duties of KMR and its directors and officers to our unitholders. The audit committee of KMR's board of directors will, at the request of KMR, review (and is one of the means for resolving) conflicts of interest that may arise between Knight or its subsidiaries, on the one hand, and us, on the other hand.

13. Leases and Commitments

Capital Leases

We acquired certain leases classified as capital leases as part of our acquisition of Kinder Morgan River Terminals LLC in October 2004. We lease our Memphis, Tennessee port facility under an agreement accounted for as a capital lease. The lease is for 24 years and expires in 2017.

Amortization of assets recorded under capital leases is included with depreciation expense. The components of property, plant and equipment recorded under capital leases are as follows (in millions):

	December 31, 2007	December 31, 2006
Leasehold improvements	$ 2.2	$ 2.2
Less: Accumulated amortization	(0.3)	(0.2)
Total	$ 1.9	$ 2.0

Future commitments under capital lease obligations as of December 31, 2007 are as follows (in millions):

Year	Commitment
2008	$ 0.2
2009	0.2
2010	0.2
2011	0.2
2012	0.2
Thereafter	0.6
Subtotal	1.6
Less: Amount representing interest	(0.6)
Present value of minimum capital lease payments	$ 1.0

Operating Leases

Including probable elections to exercise renewal options, the remaining terms on our operating leases range from one to 61 years. Future commitments related to these leases as of December 31, 2007 are as follows (in millions):

Year	Commitment
2008	$ 31.5
2009	22.8
2010	19.5
2011	15.6
2012	12.1
Thereafter	27.6
Total minimum payments	$ 129.1

The largest of these lease commitments, in terms of total obligations payable by December 31, 2008, include commitments supporting: (i) crude oil drilling rig operations for the oil and gas activities of our CO_2 business segment; (ii) marine port terminal operations at our Nassau bulk product terminal, located in Fernandina Beach, Florida; and (iii) natural gas storage in underground salt dome caverns for our Texas intrastate natural gas pipeline group.

We have not reduced our total minimum payments for future minimum sublease rentals aggregating approximately $2.0 million. Total lease and rental expenses were $49.2 million for 2007, $54.2 million for 2006 and $47.3 million for 2005.

Common Unit Option Plan

During 1998, we established a common unit option plan, which provides that key personnel of KMGP Services Company, Inc. and Knight are eligible to receive grants of options to acquire common units. The number of common units authorized under the option plan is 500,000. The option plan terminates in March 2008. The options granted generally have a term of seven years, vest 40% on the first anniversary of the date of grant and 20% on each of the next three anniversaries, and have exercise prices equal to the market price of the common units at the grant date.

As of January 1, 2006, outstanding options to purchase 15,300 common units were held by employees of Knight or KMGP Services Company, Inc. at an average exercise price of $17.82 per unit. Outstanding options to purchase 10,000 common units were held by one of our general partner's three non-employee directors at an average exercise price of $21.44 per unit. All 25,300 outstanding options were fully vested. During 2006, 4,200 options to purchase common units were cancelled or forfeited, and 21,100 options to purchase common units were exercised at an

average price of $19.67 per unit. The common units underlying these options had an average fair market value of $46.43 per unit. Accordingly, as of December 31, 2006 and 2007, there were no outstanding options.

We account for common unit options granted under our common unit option plan according to the provisions of SFAS No. 123R (revised 2004), "Share-Based Payment," which became effective for us January 1, 2006. This Statement amends SFAS No. 123, "Accounting for Stock-Based Compensation," and requires companies to expense the value of employee stock options and similar awards. According to the provisions of SFAS No. 123R, share-based payment awards result in a cost that will be measured at fair value on the awards' grant date, based on the estimated number of awards that are expected to vest. Companies will recognize compensation cost for share-based payment awards as they vest, including the related tax effects, and compensation cost for awards that vest would not be reversed if the awards expire without being exercised.

However, we have not granted common unit options or made any other share-based payment awards since May 2000, and as described above, all outstanding options to purchase our common units were fully vested as of January 1, 2006. Therefore, the adoption of this Statement did not have an effect on our consolidated financial statements due to the fact that we had reached the end of the requisite service period for any compensation cost resulting from share-based payments made under our common unit option plan.

Directors' Unit Appreciation Rights Plan

On April 1, 2003, KMR's compensation committee established our Directors' Unit Appreciation Rights Plan. Pursuant to this plan, each of KMR's three non-employee directors was eligible to receive common unit appreciation rights. Upon the exercise of unit appreciation rights, we will pay, within thirty days of the exercise date, the participant an amount of cash equal to the excess, if any, of the aggregate fair market value of the unit appreciation rights exercised as of the exercise date over the aggregate award price of the rights exercised. The fair market value of one unit appreciation right as of the exercise date will be equal to the closing price of one common unit on the New York Stock Exchange on that date. The award price of one unit appreciation right will be equal to the closing price of one common unit on the New York Stock Exchange on the date of grant. Proceeds, if any, from the exercise of a unit appreciation right granted under the plan will be payable only in cash (that is, no exercise will result in the issuance of additional common units) and will be evidenced by a unit appreciation rights agreement.

All unit appreciation rights granted vest on the six-month anniversary of the date of grant. If a unit appreciation right is not exercised in the ten year period following the date of grant, the unit appreciation right will expire and not be exercisable after the end of such period. In addition, if a participant ceases to serve on the board for any reason prior to the vesting date of a unit appreciation right, such unit appreciation right will immediately expire on the date of cessation of service and may not be exercised.

On April 1, 2003, the date of adoption of the plan, each of KMR's three non-employee directors were granted 7,500 unit appreciation rights. In addition, 10,000 unit appreciation rights were granted to each of KMR's three non-employee directors on January 21, 2004, at the first meeting of the board in 2004. During the first board meeting of 2005, the plan was terminated and replaced by the Kinder Morgan Energy Partners, L.P. Common Unit Compensation Plan for Non-Employee Directors. All unexercised awards made under our Directors' Unit Appreciation Rights Plan remain outstanding.

No unit appreciation rights were exercised during 2006. During 2007, 7,500 unit appreciation rights were exercised by one director at an aggregate fair value of $53.00 per unit. As of December 31, 2007, 45,000 unit appreciation rights had been granted, vested and remained outstanding.

Kinder Morgan Energy Partners, L.P. Common Unit Compensation Plan for Non-Employee Directors

On January 18, 2005, KMR's compensation committee established the Kinder Morgan Energy Partners, L.P. Common Unit Compensation Plan. The plan is administered by KMR's compensation committee and KMR's board has sole discretion to terminate the plan at any time. The primary purpose of this plan was to promote our interests and the interests of our unitholders by aligning the compensation of the non-employee members of the board of directors of KMR with unitholders' interests. Further, since KMR's success is dependent on its operation and management of our business and our resulting performance, the plan is expected to align the compensation of the non-employee members of the board with the interests of KMR's shareholders.

The plan recognizes that the compensation to be paid to each non-employee director is fixed by the KMR board, generally annually, and that the compensation is payable in cash. Pursuant to the plan, in lieu of receiving cash compensation, each non-employee director may elect to receive common units. Each election is made generally at or around the first board meeting in January of each calendar year and is effective for the entire calendar year. A non-employee director may make a new election each calendar year. The total number of common units authorized under this compensation plan is 100,000.

The initial election under this plan for service in 2005 was made effective January 20, 2005. The elections for 2006, 2007 and 2008 were made effective January 17, 2006, January 17, 2007 and January 16, 2008, respectively. Each annual election is evidenced by an agreement, the Common Unit Compensation Agreement, between us and each non-employee director, and this agreement contains the terms and conditions of each award. Pursuant to this agreement, all common units issued under this plan are subject to forfeiture restrictions that expire six months from the date of issuance. Until the forfeiture restrictions lapse, common units issued under the plan may not be sold, assigned, transferred, exchanged, or pledged by a non-employee director. In the event the director's service as a director of KMR is terminated prior to the lapse of the forfeiture restriction either for cause, or voluntary resignation, each director will, for no consideration, forfeit to us all common units to the extent then subject to the forfeiture restrictions. Common units with respect to which forfeiture restrictions have lapsed cease to be subject to any forfeiture restrictions, and we will provide each director a certificate representing the units as to which the forfeiture restrictions have lapsed. In addition, each non-employee director has the right to receive distributions with respect to the common units awarded to him under the plan, to vote such common units and to enjoy all other unitholder rights, including during the period prior to the lapse of the forfeiture restrictions.

The number of common units to be issued to a non-employee director electing to receive the cash compensation in the form of common units will equal the amount of such cash compensation awarded, divided by the closing price of the common units on the New York Stock Exchange on the day the cash compensation is awarded (such price, the fair market value), rounded down to the nearest 50 common units. The common units will be issuable as specified in the Common Unit Compensation Agreement. A non-employee director electing to receive the cash compensation in the form of common units will receive cash equal to the difference between (i) the cash compensation awarded to such non-employee director and (ii) the number of common units to be issued to such non-employee director multiplied by the fair market value of a common unit. This cash payment is payable in four equal installments generally around March 31, June 30, September 30 and December 31 of the calendar year in which such cash compensation is awarded.

On January 18, 2005, the date of adoption of the plan, each of KMR's three non-employee directors was awarded cash compensation of $119,750 for board service during 2005. Effective January 20, 2005, each non-employee director elected to receive compensation of $79,750 in the form of our common units and was issued 1,750 common units pursuant to the plan and its agreements (based on the $45.55 closing market price of our common units on January 18, 2005, as reported on the New York Stock Exchange). Also, consistent with the plan, the remaining $40,000 cash compensation and the $37.50 of cash compensation that did not equate to a whole common unit, based on the January 18, 2005 $45.55 closing price, was paid to each of the non-employee directors as described above. No other compensation was paid to the non-employee directors during 2005.

On January 17, 2006, each of KMR's three non-employee directors was awarded cash compensation of $160,000 for board service during 2006. Effective January 17, 2006, each non-employee director elected to receive compensation of $87,780 in the form of our common units and was issued 1,750 common units pursuant to the plan and its agreements (based on the $50.16 closing market price of our common units on January 17, 2006, as reported on the New York Stock Exchange). The remaining $72,220 cash compensation was paid to each of the non-employee directors as described above. No other compensation was paid to the non-employee directors during 2006.

On January 17, 2007, each of KMR's three non-employee directors was awarded cash compensation of $160,000 for board service during 2007. Effective January 17, 2007, each non-employee director elected to receive certain amounts of compensation in the form of our common units and each were issued common units pursuant to the plan and its agreements (based on the $48.44 closing market price of our common units on January 17, 2007, as reported on the New York Stock Exchange). Mr. Gaylord elected to receive compensation of $95,911.20 in the form of our common units and was issued 1,980 common units; Mr. Waughtal elected to receive compensation of $159,852.00 in the form of our common units and was issued 3,300 common units; and Mr. Hultquist elected to receive compensation of $96,880.00 in the form of our common units and was issued 2,000 common units. All remaining cash compensation ($64,088.80 to Mr. Gaylord; $148.00 to Mr. Waughtal; and $63,120.00 to Mr. Hultquist) was paid to each of the non-employee directors as described above, and no other compensation was paid to the non-employee directors during 2007.

On January 16, 2008, each of KMR's three non-employee directors was awarded cash compensation of $160,000 for board service during 2008; however, during a plan audit it was determined that each director was inadvertently paid an additional dividend in 2007. As a result, each director's cash compensation for service during 2008 was adjusted downward to reflect this error. The correction results in cash compensation awarded for 2008 in the amounts of $158,380.00 for Mr. Hultquist; $158,396.20 for Mr. Gaylord; and $157,327.00 for Mr. Waughtal. Effective January 16, 2008, two of the three non-employee directors elected to receive certain amounts of compensation in the form of our common units and each was issued common units pursuant to the plan and its agreements (based on the $55.81 closing market price of our common units on January 16, 2008, as reported on the New York Stock Exchange). Mr. Gaylord elected to receive compensation of $84,831.20 in the form of our common units and was issued 1,520 common units; and Mr. Waughtal elected to receive compensation of $157,272.58 in the form of our common units and was issued 2,818 common units. All remaining cash compensation ($73,565.00 to Mr. Gaylord; $54.42 to Mr. Waughtal; and $158,380.00 to Mr. Hultquist) will be paid to each of the non-employee directors as described above, and no other compensation will be paid to the non-employee directors during 2008.

14. Risk Management

Certain of our business activities expose us to risks associated with unfavorable changes in the market price of natural gas, natural gas liquids and crude oil. We also have exposure to interest rate risk as a result of the issuance of our debt obligations. Pursuant to our management's approved risk management policy, we use derivative contracts to hedge or reduce our exposure to certain of these risks, and we account for these hedging transactions according to the provisions of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" and associated amendments, collectively, SFAS No. 133.

Energy Commodity Price Risk Management

We are exposed to risks associated with unfavorable changes in the market price of natural gas, natural gas liquids and crude oil as a result of the forecasted purchase or sale of these products. Specifically, these risks are associated with unfavorable price volatility related to (i) pre-existing or anticipated physical natural gas, natural gas liquids and crude oil sales; (ii) natural gas purchases; and (iii) natural gas system use and storage.

Given our portfolio of businesses as of December 31, 2007, our principal use of energy commodity derivative contracts was to mitigate the risk associated with market movements in the price of energy commodities. The unfavorable price changes are often caused by shifts in the supply and demand for these commodities, as well as their locations. Our energy commodity derivative contracts act as a hedging (offset) mechanism against the volatility of energy commodity prices by allowing us to transfer this price risk to counterparties who are able and willing to bear it.

Hedging effectiveness and ineffectiveness

Pursuant to SFAS No. 133, our energy commodity derivative contracts are designated as cash flow hedges and for cash flow hedges, the portion of the change in the value of derivative contracts that is effective in offsetting undesired changes in expected cash flows (the effective portion) is reported as a component of other comprehensive income (outside current earnings, net income), but only to the extent that they can later offset the undesired changes in expected cash flows during the period in which the hedged cash flows affect earnings. To the contrary, the portion of the change in the value of derivative contracts that is not effective in offsetting undesired changes in expected cash flows (the ineffective portion), as well as any component excluded from the computation of the effectiveness of the derivative contracts, is required to be recognized currently in earnings. Reflecting the portion of changes in the value of derivative contracts that were not effective in offsetting underlying changes in expected cash flows (the ineffective portion of hedges), we recognized a loss of $0.1 million during 2007, a loss of $1.3 million during 2006 and a loss of $0.6 million during 2005, respectively. These recognized losses resulting from hedge ineffectiveness are reported within the captions "Natural gas sales," "Gas purchases and other costs of sales," and "Product sales and other" in our accompanying consolidated statements of income, and for each of the years ended 2007, 2006 and 2005, we did not exclude any component of the derivative contracts' gain or loss from the assessment of hedge effectiveness.

During the years 2007, 2006 and 2005, we reclassified $433.2 million, $428.1 million and $424.0 million, respectively, of "Accumulated other comprehensive loss" into earnings. With the exception of (i) an approximate $0.1 million loss reclassified in the first quarter of 2007; and (ii) a $2.9 million loss resulting from the discontinuance of cash flow hedges related to the sale of our Douglas gathering assets in 2006 (described in Note 3), none of the reclassification of "Accumulated other comprehensive loss" into earnings during 2007, 2006 or 2005 resulted from the discontinuance of cash flow hedges due to a determination that the forecasted transactions would no longer occur by the end of the originally specified time period or within an additional two-month period of time thereafter, but rather resulted from the hedged forecasted transactions actually affecting earnings (for example, when the forecasted sales and purchases actually occurred).

Our consolidated "Accumulated other comprehensive loss" balance was $1,276.6 million as of December 31, 2007 and $866.1 million as of December 31, 2006. These consolidated totals included "Accumulated other comprehensive loss" amounts associated with the commodity price risk management activities of $1,377.2 million as of December 31, 2007 and $838.7 million as of December 31, 2006. Approximately $553.3 million of this total accumulated loss associated with our commodity price risk management activities as of December 31, 2007 is expected to be reclassified into earnings during the next twelve months (when the associated forecasted sales and purchases are also expected to occur).

Fair Value of Energy Commodity Derivative Contracts

The fair values of the energy commodity derivative contracts we use, including commodity futures and options contracts, fixed price swaps, and basis swaps are included in our accompanying consolidated balance sheets within "Other current assets," "Deferred charges and other assets," "Accrued other current liabilities," and "Other long-term liabilities and deferred credits." The following table summarizes the fair values of our energy commodity derivative contracts associated with our commodity price risk management activities and included on our accompanying consolidated balance sheets as of December 31, 2007 and December 31, 2006 (in millions):

	December 31, 2007	**December 31, 2006**
Derivatives-net asset/(liability)		
Other current assets	$ 37.0	$ 91.9
Deferred charges and other assets	4.4	12.7
Accrued other current liabilities	(593.9)	(431.4)
Other long-term liabilities and deferred credits	$ (836.8)	$ (510.2)

As of December 31, 2007, the maximum length of time over which we have hedged our exposure to the variability in future cash flows associated with commodity price risk is through December 2012.

Credit Risks

We have counterparty credit risk as a result of our use of energy commodity derivative contracts. Our over-the-counter swaps and options are contracts we entered into with counterparties outside centralized trading facilities such as a futures, options or stock exchange. These contracts are with a number of parties, all of which had investment grade credit ratings as of December 31, 2007. We both owe money and are owed money under these derivative contracts. While we enter into derivative contracts principally with investment grade counterparties and actively monitor their credit ratings, it is nevertheless possible that from time to time losses will result from counterparty credit risk in the future.

Additionally, in conjunction with the purchase of exchange-traded derivative contracts or when the market value of our derivative contracts with specific counterparties exceeds established limits, we are required to provide collateral to our counterparties, which may include posting letters of credit or placing cash in margin accounts. As of December 31, 2007 and December 31, 2006, we had three outstanding letters of credit totaling $298.0 million and $243.0 million, respectively, in support of our hedging of commodity price risks associated with the sale of natural gas, natural gas liquids and crude oil.

As of December 31, 2007, we had cash margin deposits associated with our commodity contract positions and over-the-counter swap partners totaling $67.9 million, and we reported this amount as "Restricted deposits" in our accompanying consolidated balance sheet as of December 31, 2007. As of December 31, 2006, our counterparties associated with our commodity contract positions and over-the-counter swap agreements had margin deposits with us totaling $2.3 million, and we reported this amount within "Accrued other liabilities" in our accompanying consolidated balance sheet as of December 31, 2006.

Interest Rate Risk Management

In order to maintain a cost effective capital structure, it is our policy to borrow funds using a mix of fixed rate debt and variable rate debt. We use interest rate swap agreements to manage the interest rate risk associated with the fair value of our fixed rate borrowings and to effectively convert a portion of the underlying cash flows related to our long-term fixed rate debt securities into variable rate cash flows in order to achieve our desired mix of fixed and variable rate debt.

Since the fair value of fixed rate debt varies inversely with changes in the market rate of interest, we enter into swap agreements to receive a fixed and pay a variable rate of interest in order to convert the interest expense associated with certain of our senior notes from fixed rates to floating rates, resulting in future cash flows that vary with the market rate of interest. These swaps, therefore, hedge against changes in the fair value of our fixed rate debt that result from market interest rate changes.

As of December 31, 2006, we were a party to interest rate swap agreements with notional principal amounts of $2.1 billion. In the first six months of 2007, we both entered into additional fixed-to-floating interest rate swap agreements having a combined notional principal amount of $500 million and terminated an existing fixed-to-floating interest rate swap agreement having a notional principal amount of $100 million and a maturity date of March 15, 2032. We received $15.0 million from the early termination of this swap agreement, and this amount is being amortized over the remaining term of the original swap period.

On August 15, 2007, two separate fixed-to-floating interest rate swap agreements having a combined notional principal amount of $200 million matured, and as of December 31, 2007, we had a combined notional principal amount of $2.3 billion of fixed-to-floating interest rate swap agreements effectively converting the interest expense associated with certain series of our senior notes from fixed rates to variable rates based on an interest rate of LIBOR plus a spread. The two swap agreements that matured on August 15, 2007 were associated with the $250 million of 5.35% senior notes that also matured on that date. In February 2007, we entered into additional fixed-to-floating interest rate swap agreements having a combined notional principal amount of $600 million. These swap agreements were related to the $600 million of 5.95% senior notes we issued on February 12, 2008, and have a maturity date of February 15, 2018.

All of our interest rate swap agreements have a termination date that corresponds to the maturity date of one of our series of senior notes and, as of December 31, 2007, the maximum length of time over which we have hedged a portion of our exposure to the variability in the value of this debt due to interest rate risk is through January 15, 2038. In addition, certain of our swap agreements contain mutual cash-out provisions that allow us or our counterparties to settle the agreement at certain future dates before maturity based on the then-economic value of the swap agreement.

Hedging effectiveness and ineffectiveness

Our interest rate swap contracts have been designated as fair value hedges and meet the conditions required to assume no ineffectiveness under SFAS No. 133. Therefore, we have accounted for them using the "shortcut" method prescribed by SFAS No. 133 and accordingly, we adjust the carrying value of each swap contract to its fair value each quarter, with an offsetting entry to adjust the carrying value of the debt securities whose fair value is being hedged. We record interest expense equal to the variable rate payments under the swap contracts.

Fair Value of Interest Rate Swap Agreements

The fair values of our interest rate swap agreements are included within "Deferred charges and other assets" and "Other long-term liabilities and deferred credits" in our accompanying consolidated balance sheets. The offsetting entry to adjust the carrying value of the debt securities whose fair value was being hedged is included within "Value of interest rate swaps" on our accompanying consolidated balance sheets, which also includes any unamortized portion of proceeds received from the early termination of interest rate swap agreements. As of December 31, 2007, this unamortized premium totaled $14.2 million, representing the unamortized proceeds we received from the swap agreement we terminated in the first quarter of 2007.

The following table summarizes the net fair value of our interest rate swap agreements associated with our interest rate risk management activities and included on our accompanying consolidated balance sheets as of December 31, 2007 and December 31, 2006 (in millions):

	December 31, 2007	December 31, 2006
Derivatives-net asset/(liability)		
Deferred charges and other assets	$ 138.0	$ 65.2
Other long-term liabilities and deferred credits	—	(22.6)
Net fair value of interest rate swaps	$ 138.0	$ 42.6

Furthermore, we are exposed to credit related losses in the event of nonperformance by counterparties to our interest rate swap agreements, and while we enter into derivative contracts primarily with investment grade counterparties and actively monitor their credit ratings, it is nevertheless possible that from time to time losses will result from counterparty credit risk. As of December 31, 2007, all of our interest rate swap agreements were with counterparties with investment grade credit ratings.

Other

Certain of our business activities expose us to foreign currency fluctuations. However, due to the limited size of this exposure, we do not believe the risks associated with changes in foreign currency will have a material adverse effect on our business, financial position, results of operations or cash flows. As a result, we do not significantly hedge our exposure to fluctuations in foreign currency.

15. Reportable Segments

We divide our operations into five reportable business segments:

- Products Pipelines;
- Natural Gas Pipelines;
- CO_2;
- Terminals; and
- Trans Mountain.

Each segment uses the same accounting policies as those described in the summary of significant accounting policies (see Note 2). We evaluate performance principally based on each segments' earnings before depreciation, depletion and amortization, which excludes general and administrative expenses, third-party debt costs and interest expense, unallocable interest income and income tax expense, and minority interest. Our reportable segments are strategic business units that offer different products and services. Each segment is managed separately because each segment involves different products and marketing strategies.

Our Products Pipelines segment derives its revenues primarily from the transportation and terminaling of refined petroleum products, including gasoline, diesel fuel, jet fuel and natural gas liquids. Our Natural Gas Pipelines segment derives its revenues primarily from the sale, transport, processing, treating, storage and gathering of natural gas. Our CO_2 segment derives its revenues primarily from the production and sale of crude oil from fields in the Permian Basin of West Texas and from the transportation and marketing of carbon dioxide used as a flooding medium for recovering crude oil from mature oil fields. Our Terminals segment derives its revenues primarily from the transloading and storing of refined petroleum products and dry and liquid bulk products, including coal, petroleum coke, cement, alumina, salt and other bulk chemicals. Our Trans Mountain business segment derives its revenues primarily from the transportation of crude oil and refined products from Edmonton, Alberta to marketing terminals and refineries in the Greater Vancouver area and Puget Sound in Washington State.

As discussed in Note 3, due to the sale of our North System, an approximate 1,600-mile interstate common carrier pipeline system whose operating results were included as part of our Products Pipelines business segment, we accounted for the North System business as a discontinued operation. Consistent with the management approach of identifying and reporting discrete financial information on operating segments, we have included the North System's financial results within our Products Pipelines business segment disclosures for all periods presented in this report and, as prescribed by SFAS No. 131, we have reconciled the total of our reportable segment's financial results to our consolidated financial results by separately identifying, in the following pages where applicable, the North System amounts as discontinued operations.

Financial information by segment follows (in millions):

	2007	2006	2005
Revenues			
Products Pipelines			
Revenues from external customers	$ 844.4	$ 776.3	$ 711.8
Intersegment revenues	—	—	—
Natural Gas Pipelines			
Revenues from external customers	6,466.5	6,577.7	7,718.4
Intersegment revenues	—	—	—
CO_2			
Revenues from external customers	824.1	736.5	657.6
Intersegment revenues	—	—	—
Terminals			
Revenues from external customers	963.0	864.1	699.3
Intersegment revenues	0.7	0.7	—
Trans Mountain			
Revenues from external customers	160.8	137.8	—
Intersegment revenues	—	—	—
Total segment revenues	9,259.5	9,093.1	9,787.1
Less: Total intersegment revenues	(0.7)	(0.7)	—
	9,258.8	9,092.4	9,787.1
Less: Discontinued operations	(41.1)	(43.7)	(41.2)
Total consolidated revenues	$ 9,217.7	$ 9,048.7	$ 9,745.9

	2007	2006	2005
Operating expenses(a)			
Products Pipelines	$ 451.8	$ 308.3	$ 366.0
Natural Gas Pipelines	5,882.9	6,057.8	7,255.0
CO_2	304.2	268.1	212.6
Terminals	536.4	461.9	373.4
Trans Mountain	65.9	53.3	—
Total segment operating expenses	7,241.2	7,149.4	8,207.0
Less: Total intersegment operating expenses	(0.7)	(0.7)	—
	7,240.5	7,148.7	8,207.0
Less: Discontinued operations	(14.8)	(22.7)	(35.2)
Total consolidated operating expenses	$ 7,225.7	$ 7,126.0	$ 8,171.8
Other expense (income)			
Products Pipelines	$ (154.8)	$ —	$ —
Natural Gas Pipelines	(3.2)	(15.1)	—
CO_2	—	—	—
Terminals	(6.3)	(15.2)	—
Trans Mountain(b)	377.1	(0.9)	—
Total segment Other expense (income)	212.8	(31.2)	—
Less: Discontinued operations	152.8	—	—
Total consolidated Other expense (income)	$ 365.6	$ (31.2)	$ —
Depreciation, depletion and amortization			
Products Pipelines	$ 89.2	$ 82.9	$ 79.1
Natural Gas Pipelines	64.8	65.4	61.7
CO_2	282.2	190.9	149.9
Terminals	89.3	74.6	59.1
Trans Mountain	21.5	19.0	—
Total segment depreciation, depletion and amortiz.	547.0	432.8	349.8
Less: Discontinued operations	(7.0)	(8.9)	(8.2)
Total consol. depreciation, depletion and amortiz.	$ 540.0	$ 423.9	$ 341.6
Earnings from equity investments			
Products Pipelines	$ 32.5	$ 16.3	$ 28.5
Natural Gas Pipelines	19.2	40.5	36.8
CO_2	19.2	19.2	26.3
Terminals	0.6	0.2	0.1
Trans Mountain	—	—	—
Total segment earnings from equity investments	71.5	76.2	91.7
Less: Discontinued operations	(1.8)	(2.2)	(2.1)
Total consolidated equity earnings	$ 69.7	$ 74.0	$ 89.6
Amortization of excess cost of equity investments			
Products Pipelines	$ 3.4	$ 3.4	$ 3.4
Natural Gas Pipelines	0.4	0.3	0.2
CO_2	2.0	2.0	2.0
Terminals	—	—	—
Trans Mountain	—	—	—
Total segment amortization of excess cost of invests.	5.8	5.7	5.6
Less: Discontinued operations	—	(0.1)	(0.1)

Total consol. amortization of excess cost of invests.	$	5.8	$	5.6	$	5.5
Interest income						
Products Pipelines	$	4.4	$	4.5	$	4.6
Natural Gas Pipelines		—		0.1		0.7
CO_2		—		—		—
Terminals		—		—		—
Trans Mountain		—		—		—
Total segment interest income		4.4		4.6		5.3
Unallocated interest income		1.3		3.1		4.1
Total consolidated interest income	$	5.7	$	7.7	$	9.4

	2007	2006	2005
Other, net-income (expense)			
Products Pipelines	$ 5.0	$ 7.6	$ 1.5
Natural Gas Pipelines	0.2	0.6	2.0
CO_2	—	0.8	—
Terminals	1.0	2.1	(0.2)
Trans Mountain	8.0	1.0	—
Total segment other, net-income (expense)	14.2	12.1	3.3
Less: Discontinued operations	—	(0.1)	—
Total consolidated other, net-income (expense)	$ 14.2	$ 12.0	$ 3.3
Income tax benefit (expense)			
Products Pipelines	$ (19.7)	$ (5.2)	$ (10.3)
Natural Gas Pipelines	(6.0)	(1.4)	(2.6)
CO_2	(2.1)	(0.2)	(0.4)
Terminals	(19.2)	(12.3)	(11.2)
Trans Mountain	(19.4)	(9.9)	—
Total segment income tax benefit (expense)	(66.4)	(29.0)	(24.5)
Unallocated income tax benefit (expense)	(4.6)	—	—
Total consolidated income tax benefit (expense)	$ (71.0)	$ (29.0)	$ (24.5)
Segment earnings(c)			
Products Pipelines	$ 477.0	$ 404.9	$ 287.6
Natural Gas Pipelines	535.0	509.1	438.4
CO_2	252.8	295.3	319.0
Terminals	326.7	333.5	255.5
Trans Mountain	(315.1)	57.5	—
Total segment earnings	1,276.4	1,600.3	1,300.5
Interest and corporate administrative expenses(d)	(686.1)	(596.2)	(488.3)
Total consolidated net income	$ 590.3	$ 1,004.1	$ 812.2
Segment earnings before depreciation, depletion, amortization and amortization of excess cost of equity investments(e)			
Products Pipelines	$ 569.6	$ 491.2	$ 370.1
Natural Gas Pipelines	600.2	574.8	500.3
CO_2	537.0	488.2	470.9
Terminals	416.0	408.1	314.6
Trans Mountain	(293.6)	76.5	—
Total segment earnings before DD&A	1,829.2	2,038.8	1,655.9
Total segment depreciation, depletion and amortiz.	(547.0)	(432.8)	(349.8)
Total segment amortization of excess cost of invests.	(5.8)	(5.7)	(5.6)
Interest and corporate administrative expenses	(686.1)	(596.2)	(488.3)
Total consolidated net income	$ 590.3	$ 1,004.1	$ 812.2
Capital expenditures(f)			
Products Pipelines	$ 259.4	$ 196.0	$ 271.5
Natural Gas Pipelines	264.0	271.6	102.9
CO_2	382.5	283.0	302.1
Terminals	480.0	307.7	186.6
Trans Mountain	305.7	123.8	—
Total consolidated capital expenditures	$ 1,691.6	$ 1,182.1	$ 863.1

Investments at December 31			
Products Pipelines	$ 202.3	$ 211.1	$ 223.7
Natural Gas Pipelines	427.5	197.9	177.1
CO_2	14.2	16.1	17.9
Terminals	10.6	0.5	0.6
Trans Mountain	0.8	0.7	—
Total consolidated investments	$ 655.4	$ 426.3	$ 419.3

	2007	2006	2005
Assets at December 31			
Products Pipelines	$ 4,045.0	$ 3,910.5	$ 3,873.9
Natural Gas Pipelines	4,347.3	3,946.6	4,140.0
CO_2	2,004.5	1,870.8	1,772.8
Terminals	3,036.4	2,397.5	2,052.5
Trans Mountain	1,440.8	1,314.0	—
Total segment assets	14,874.0	13,439.4	11,839.2
Corporate assets(g)	303.8	102.8	84.3
Total consolidated assets	$ 15,177.8	$ 13,542.2	$ 11,923.5

(a) Includes natural gas purchases and other costs of sales, operations and maintenance expenses, fuel and power expenses and taxes, other than income taxes.

(b) 2007 amount represents an expense of $377.1 million attributable to a goodwill impairment charge recognized by Knight, as discussed in Notes 3 and 8.

(c) Includes revenues, earnings from equity investments, allocable interest income, and other, net, less operating expenses, allocable income taxes, other expense (income), depreciation, depletion and amortization, and amortization of excess cost of equity investments.

(d) Includes unallocated interest income and income tax expense, interest and debt expense, general and administrative expenses, and minority interest expense.

(e) Includes revenues, earnings from equity investments, allocable interest income, and other, net, less operating expenses, allocable income taxes, and other expense (income).

(f) Includes sustaining capital expenditures of $152.6 million in 2007 (not including Trans Mountain for periods prior to our acquisition date of April 30, 2007), $125.5 million in 2006 (not including Trans Mountain) and $140.8 million in 2005. Sustaining capital expenditures are defined as capital expenditures which do not increase the capacity of an asset.

(g) Includes cash and cash equivalents, margin and restricted deposits, certain unallocable deferred charges, and risk management assets related to the fair value of interest rate swaps.

We do not attribute interest and debt expense to any of our reportable business segments. For each of the years ended December 31, 2007, 2006 and 2005, we reported (in millions) total consolidated interest expense of $397.1 million, $345.5 million and $268.4 million, respectively.

Our total operating revenues are derived from a wide customer base. For each of the three years ended December 31, 2007, 2006 and 2005, no revenues from transactions with a single external customer amounted to 10% or more of our total consolidated revenues.

Following is geographic information regarding the revenues and long-lived assets of our business segments (in millions):

	2007	2006	2005
Revenues from external customers			
United States	$ 8,986.3	$ 8,889.9	$ 9,715.1
Canada	211.9	139.3	11.8
Mexico and other(a)	19.5	19.5	19.0
Total consol. revenues from external customers	$ 9,217.7	$ 9,048.7	$ 9,745.9
Long-lived assets at December 31(b)			
United States	$ 11,054.3	$ 9,917.2	$ 9,442.8
Canada	1,420.0	766.4	48.2
Mexico and other	89.5	91.4	92.3
Total consolidated long-lived assets	$ 12,563.8	$ 10,775.0	$ 9,583.3

(a) Includes operations in Mexico and the Netherlands.

(b) Long-lived assets exclude (i) goodwill; (ii) other intangibles, net; and (iii) long-term note receivables from related parties.

16. Litigation, Environmental and Other Contingencies

Below is a brief description of our ongoing material legal proceedings, including any material developments that occurred in such proceedings during 2007. This note also contains a description of any material legal proceeding initiated during 2007 in which we are involved.

Federal Energy Regulatory Commission Proceedings

Our SFPP, L.P. and CALNEV Pipe Line LLC subsidiaries are involved in proceedings before the Federal Energy Regulatory Commission. SFPP is the subsidiary limited partnership that owns our Pacific operations. CALNEV Pipe Line LLC and related terminals was acquired from GATX Corporation and is not part of the Pacific Operations. The tariffs and rates charged by SFPP and CALNEV are subject to numerous ongoing proceedings at the Federal Energy Regulatory Commission, referred to in this report as the FERC, including shippers' complaints and protests regarding interstate rates on these pipeline systems. In general, these complaints allege the rates and tariffs charged by SFPP and CALNEV are not just and reasonable.

As to SFPP, the issues involved in these proceedings include, among others: (i) whether certain of our Pacific operations' rates are "grandfathered" under the Energy Policy Act of 1992, referred to in this note as EPAct 1992, and therefore deemed to be just and reasonable; (ii) whether "substantially changed circumstances" have occurred with respect to any grandfathered rates such that those rates could be challenged; (iii) whether indexed rate increases may become effective without investigation; (iv) the capital structure to be used in computing the "starting rate base" of our Pacific operations; (v) the level of income tax allowance we may include in our rates; and (vi) the recovery of civil and regulatory litigation expenses and certain pipeline reconditioning and environmental costs incurred by our Pacific operations.

In May 2005, the FERC issued a statement of general policy stating it will permit pipelines to include in cost of service a tax allowance to reflect actual or potential tax liability on their public utility income attributable to all partnership or limited liability company interests, if the ultimate owner of the interest has an actual or potential income tax liability on such income. Whether a pipeline's owners have such actual or potential income tax liability will be reviewed by the FERC on a case-by-case basis. Although the new policy is generally favorable for pipelines that are organized as pass-through entities, it still entails rate risk due to the case-by-case review requirement. The new tax allowance policy and the FERC's application of that policy to our Pacific operations were appealed to the United States Court of Appeals for the District of Columbia Circuit, referred to in this note as the D.C. Court.

On May 29, 2007, the D.C. Court issued an opinion upholding the FERC's tax allowance policy. Because the extent to which an interstate oil pipeline is entitled to an income tax allowance is subject to a case-by-case review at the FERC, the level of income tax allowance to which SFPP will ultimately be entitled is not certain. The D.C. Court's May 29 decision also upheld the FERC's determination that a rate is no longer subject to grandfathering protection under EPAct 1992 when there has been a substantial change in the overall rate of return of the pipeline, rather than in one cost element. Further, the D.C. Court declined to consider arguments that there were errors in the FERC's method for determining substantial change, finding that the parties had not first raised such allegations with the FERC. On July 13, 2007, SFPP filed a petition for rehearing with the D.C. Court, arguing that SFPP did raise allegations with the FERC respecting these calculation errors. The D.C. Circuit denied rehearing of the May 29, 2007 decision on August 20, 2007, and the decision is now final.

In this note, we refer to SFPP, L.P. as SFPP; CALNEV Pipe Line LLC as Calnev; Chevron Products Company as Chevron; Navajo Refining Company, L.P. as Navajo; ARCO Products Company as ARCO; BP West Coast Products, LLC as BP WCP; Texaco Refining and Marketing Inc. as Texaco; Western Refining Company, L.P. as Western Refining; Mobil Oil Corporation as Mobil; ExxonMobil Oil Corporation as ExxonMobil; Tosco Corporation as Tosco; ConocoPhillips Company as ConocoPhillips; Ultramar Diamond Shamrock Corporation as Ultramar; Valero Energy Corporation as Valero; Valero Marketing and Supply Company as Valero Marketing; and America West Airlines, Inc., Continental Airlines, Inc., Northwest Airlines, Inc., Southwest Airlines Co. and US Airways, Inc., collectively, as the Airline Complainants.

Following is a listing of certain active FERC proceedings pertaining to our Pacific operations:

- FERC Docket No. OR92-8, *et al.*—Complainants/Protestants: Chevron; Navajo; ARCO; BP WCP; Western Refining; ExxonMobil; Tosco; and Texaco (Ultramar is an intervenor)—Defendant: SFPP Consolidated proceeding involving shipper complaints against certain East Line and West Line rates. All five issues (and others) described four paragraphs above are involved in these proceedings. Portions of this proceeding were appealed (and re-appealed) to the D.C. Court and remanded to the FERC. BP WCP, Chevron, and ExxonMobil requested a hearing before the FERC on remanded grandfathering and income tax allowance issues. The FERC issued an Order on Rehearing, Remand, Compliance, and Tariff Filings on December 26, 2007, which denied the requests for a hearing, affirmed the income tax allowance policy and further clarified the implementation of that policy, and required SFPP to file a compliance filing;

- FERC Docket Nos. OR92-8-028, *et al.*—Complainants/Protestants: BP WCP; ExxonMobil; Chevron; ConocoPhillips; and Ultramar—Defendant: SFPP
  Proceeding involving shipper complaints against SFPP's Watson Station rates. A settlement was reached for April 1, 1999 forward; whether SFPP owes reparations for shipments prior to that date is still before the FERC;

- FERC Docket No. OR96-2, *et al.*—Complainants/Protestants: All Shippers except Chevron (which is an intervenor)—Defendant: SFPP Consolidated proceeding involving shipper complaints against all SFPP rates. All five issues (and others) described four paragraphs above are involved in these proceedings. Portions of this proceeding were appealed (and re-appealed) to the D.C. Court and remanded to the FERC. The FERC issued an Order on Rehearing, Remand, Compliance, and Tariff Filings on December 26, 2007, which denied the requests for a hearing, affirmed the income tax allowance policy and further clarified the implementation of that policy, and required SFPP to file a compliance filing;

- FERC Docket Nos. OR02-4 and OR03-5—Complainant/Protestant: Chevron—Defendant: SFPP
  Chevron initiated proceeding to permit Chevron to become complainant in OR96-2. Appealed to the D.C. Court and held in abeyance pending final disposition of the OR96-2 proceedings;

- FERC Docket No. OR04-3—Complainants/Protestants: America West Airlines; Southwest Airlines; Northwest Airlines; and Continental Airlines—Defendant: SFPP
  Complaint alleges that West Line and Watson Station rates are unjust and unreasonable. Watson Station issues severed and consolidated into a proceeding focused only on Watson-related issues. The FERC has set the complaints against the West Line rates for hearing but denied the request to consolidate the dockets with the ongoing proceedings involving SFPP's North and Oregon Line rates;

- FERC Docket Nos. OR03-5, OR05-4 and OR05-5—Complainants/Protestants: BP WCP; ExxonMobil; and ConocoPhillips (other shippers intervened)—Defendant: SFPP
  Complaints allege that SFPP's interstate rates are not just and reasonable. The FERC has set the complaints against the West and East Line rates for hearing, but denied the request to consolidate the dockets with the ongoing proceedings involving SFPP's North and Oregon Line rates;

- FERC Docket No. OR03-5-001—Complainants/Protestants: BP WCP; ExxonMobil; and ConocoPhillips (other shippers intervened)—Defendant: SFPP
  The FERC severed the portions of the complaints in Docket Nos. OR03-5, OR05-4, and OR05-5 regarding SFPP's North and Oregon Line rates into a separate proceeding in Docket No. OR03-5-001, which has been set for hearing;

- FERC Docket No. OR07-1—Complainant/Protestant: Tesoro—Defendant: SFPP
  Complaint alleges that SFPP's North Line rates are not just and reasonable. Complaint held in abeyance pending resolution at the D.C. Court of, among other things, income tax allowance and grandfathering issues. The D.C. Court issued an opinion on these issues on May 29, 2007, upholding the FERC's income tax allowance policy;

- FERC Docket No. OR07-2—Complainant/Protestant: Tesoro—Defendant: SFPP
  Complaint alleges that SFPP's West Line rates are not just and reasonable. Complaint held in abeyance pending resolution at the D.C. Court of, among other things, income tax allowance and grandfathering issues. The D.C. Court issued an opinion on these issues on May 29, 2007, upholding the FERC's income tax allowance policy. A request that the FERC set the complaint for hearing – which SFPP opposed – is pending before the FERC;

- FERC Docket No. OR07-3—Complainants/Protestants: BP WCP; Chevron; ExxonMobil; Tesoro; and Valero Marketing—Defendant: SFPP
  Complaint alleges that SFPP's North Line indexed rate increase was not just and reasonable. The FERC has dismissed the complaint and denied rehearing the dismissal. Petitions for review filed by BP WCP and ExxonMobil at the D.C. Court;

- FERC Docket No. OR07-4—Complainants/Protestants: BP WCP; Chevron; and ExxonMobil—Defendants: SFPP; Kinder Morgan G.P., Inc.; and Knight Inc.
  Complaint alleges that SFPP's rates are not just and reasonable. Complaint held in abeyance pending resolution at the D.C. Court of, among other things, income tax allowance and grandfathering issues. The D.C. Court issued an opinion on these issues on May 29, 2007, upholding the FERC's income tax allowance policy;

- FERC Docket Nos. OR07-5 and OR07-7 (consolidated)—Complainants/Protestants: ExxonMobil and Tesoro—Defendants: Calnev; Kinder Morgan G.P., Inc.; and Knight Inc.
  Complaints allege that none of Calnev's current rates are just or reasonable. In light of the D.C. Court's May 29, 2007 ruling, on July 19, 2007, the FERC, among other things, dismissed with prejudice the complaints against Kinder Morgan GP Inc. and Knight, Inc. and allowed complainants to file amended complaints. ExxonMobil filed a request for rehearing of the dismissal of the complaints against Kinder Morgan GP, Inc. and Knight Inc., which is currently pending before the FERC. The FERC has not acted on the amended complaints;

- FERC Docket No. OR07-6—Complainant/Protestant: ConocoPhillips—Defendant: SFPP
  Complaint alleges that SFPP's North Line indexed rate increase was not just and reasonable. The FERC has dismissed the complaint and denied rehearing of the dismissal. The FERC had consolidated this case with OR07-3 and issued orders that applied to both OR07-3 and OR07-6. Although the FERC orders in these dockets have been appealed by certain of the complainants in OR07-3, they have not been appealed by ConocoPhillips in OR07-6;

- FERC Docket No. OR07-8 (consolidated with Docket No. OR07-11)—Complainant/Protestant: BP WCP—Defendant: SFPP
  Complaint alleges that SFPP's 2005 indexed rate increase was not just and reasonable. On June 6, 2007, the FERC dismissed challenges to SFPP's underlying rate but held in abeyance the portion of the Complaint addressing SFPP's July 1, 2005 index-based rate increases. SFPP requested rehearing on July 6, 2007, which the FERC denied. On February 13, 2008, the FERC set this complaint for hearing, but referred it to settlement negotiations;

- FERC Docket No. OR07-9—Complainant/Protestant: BP WCP—Defendant: SFPP
  Complaint alleges that SFPP's ultra low sulphur diesel (ULSD) recovery fee violates the filed rate doctrine and that, in any event, the recovery fee is unjust and unreasonable. On July 6, 2007, the FERC dismissed the complaint. BP WCP requested rehearing, which the FERC denied. A petition for review was filed by BP WCP. The FERC's motion to dismiss or hold the case in abeyance is pending;

- FERC Docket No. OR07-10—Complainants/Protestants: BP WCP; ConocoPhillips; Valero; and ExxonMobil—Defendant: Calnev
  Calnev filed a petition with the FERC on May 14, 2007, requesting that the FERC issue a declaratory order approving Calnev's proposed rate methodology and granting other relief with respect to a substantial proposed expansion of Calnev's mainline pipeline system. On July 20, 2007, the FERC granted Calnev's petition for declaratory order;

- FERC Docket No. OR07-11 (consolidated with Docket No. OR07-8)—Complainant/Protestant: ExxonMobil—Defendant: SFPP
Complaint alleges that SFPP's 2005 indexed rate increase was not just and reasonable. On February 13, 2008, the FERC set this complaint for hearing, but referred it to settlement negotiations. It is consolidated with the complaint in Docket No. OR07-8;

- FERC Docket No. OR07-14—Complainants/Protestants: BP WCP and Chevron—Defendants: SFPP; Calnev; Operating Limited Partnership "D"; Kinder Morgan Energy Partners, L.P.; Kinder Morgan Management LLC; Kinder Morgan General Partner, Inc.; Knight Inc.; and Knight Holdco, LLC Complaint alleges violations of the Interstate Commerce Act and FERC's cash management regulations, seeks review of the FERC Form 6 annual reports of SFPP and Calnev, and again requests interim refunds and reparations. The FERC dismissed the complaints;

- FERC Docket No. OR07-16—Complainant/Protestant: Tesoro—Defendant: Calnev
Complaint challenges Calnev's 2005, 2006, and 2007 indexing adjustments. The FERC dismissed the complaint. A petition for review was filed by Tesoro. A scheduling order for briefs and oral argument has not yet been issued by the D.C. Court;

- FERC Docket No. OR07-18—Complainants/Protestants: Airline Complainants; Chevron; and Valero Marketing—Defendant: Calnev
Complaint alleges that Calnev's rates are unjust and unreasonable and that none of Calnev's rates are grandfathered under EPAct 1992. In December 2007, the FERC issued an order accepting and holding in abeyance the portion of the complaint against the non-grandfathered portion of Calnev's rates. The order also gave complainants 45 days to amend their complaint against the grandfathered portion of Calnev's rates in light of clarifications provided in the FERC's order;

- FERC Docket No. OR07-19—Complainant/Protestant: ConocoPhillips—Defendant: Calnev
Complaint alleges that Calnev's rates are unjust and unreasonable and that none of Calnev's rates are grandfathered under EPAct 1992. In December 2007, the FERC issued an order accepting and holding in abeyance the portion of the complaint against the non-grandfathered portion of Calnev's rates. The order also gave complainants 45 days to amend their complaint against the grandfathered portion of Calnev's rates in light of clarifications provided in the FERC's order;

- FERC Docket No. OR07-20—Complainant/Protestant: BP WCP—Defendant: SFPP
Complaint alleges that SFPP's 2007 indexed rate increase was not just and reasonable. In December 2007, the FERC dismissed the complaint. Complainant filed a request for rehearing which is currently pending before the FERC. In February 2008, the FERC accepted a joint offer of settlement that dismisses, with prejudice, the East Line index rate portion of the complaint in OR07-20;

- FERC Docket No. OR07-22—Complainant/Protestant: BP WCP—Defendant: Calnev
Complaint alleges that Calnev's rates are unjust and unreasonable and that none of Calnev's rates are grandfathered under EPAct 1992. In December 2007, the FERC issued an order giving complainant 45 days to amend its complaint in light of guidance provided by the FERC;

- FERC Docket No. IS05-230 (North Line rate case)—Complainants/Protestants: Shippers—Defendant: SFPP
SFPP filed to increase North Line rates to reflect increased costs due to installation of new pipe between Concord and Sacramento, California. Various shippers protested. Administrative law judge decision pending before the FERC on exceptions. On August 31, 2007, BP WCP and ExxonMobil filed a motion to reopen the record on the issue of SFPP's appropriate rate of return on equity, which SFPP answered on September 18, 2007. The FERC has yet to issue an order on shipper's motion;

- FERC Docket No. IS05-327—Complainants/Protestants: Shippers—Defendant: SFPP
SFPP filed to increase certain rates on its pipelines pursuant to FERC's indexing methodology. Various shippers protested, but FERC determined that the tariff filings were consistent with its regulations. The D.C. Court dismissed a petition for review, citing a lack of jurisdiction to review a decision by FERC not to order an investigation;

- FERC Docket No. IS06-283 (East Line rate case)—Complainants/Protestants: Shippers—Defendant: SFPP
SFPP filed to increase East Line rates to reflect increased costs due to installation of new pipe between El Paso, Texas and Tucson, Arizona. Various shippers protested. In November 2007, the parties submitted a joint offer of settlement which was certified to the FERC in December 2007. In February 2008, the FERC accepted the joint offer of settlement which, among other things, resolved all protests and complaints related to the East Line Phase I Expansion Tariff;

- FERC Docket No. IS06-296—Complainant/Protestant: ExxonMobil—Defendant: Calnev
Calnev sought to increase its interstate rates pursuant to the FERC's indexing methodology. ExxonMobil filed a protest respecting Calnev's indexing adjustments. This proceeding is currently held in abeyance pending ongoing settlement discussions. Calnev has also filed a motion to dismiss or, to hold the investigation in abeyance, which is pending before the FERC. Calnev and ExxonMobil have reached an agreement in principle to settle this and other dockets;

- FERC Docket No. IS06-356—Complainants/Protestants: Shippers—Defendant: SFPP
SFPP filed to increase certain rates on its pipelines pursuant to FERC's indexing methodology. Various shippers protested, but FERC found the tariff filings consistent with its regulations. FERC has rescinded the index increase for the East Line rates, and SFPP has requested rehearing. The D.C. Court dismissed a petition for review, citing the rehearing request pending before the FERC. On September 20, 2007, the FERC denied SFPP's request for rehearing. In November 2007, all parties submitted a joint offer of settlement. In February 2008, the FERC accepted the joint offer of settlement which, among other things, resolved all protests and complaints related to the East Line 2006 Index Tariff;

- FERC Docket No. IS07-137 (ULSD surcharge)—Complainants/Protestants: Shippers—Defendant: SFPP SFPP filed tariffs to include a per barrel ULSD recovery fee and a surcharge for ULSD-related litigation costs on diesel products. Various shippers protested. Tariffs related to ULSD recovery fee accepted subject to refund and proceeding is being held in abeyance pending resolution of other proceedings involving SFPP. SFPP rescinded the ULSD litigation surcharge in compliance with FERC order. Request for rehearing filed by Chevron and Tesoro. The FERC ultimately denied rehearing in an order issued on November 13, 2007;

- FERC Docket No. IS07-229—Complainants/Protestants: BP WCP and ExxonMobil—Defendant: SFPP SFPP filed to increase certain rates on its pipelines pursuant to FERC's indexing methodology. Two shippers filed protests. The FERC found the tariff filings consistent with its regulations but suspended the increased rates subject to refund pending challenges to SFPP's underlying rates. In November 2007, all parties submitted a joint offer of settlement. In February 2008, the FERC accepted the joint offer of settlement which, among other things, resolved all protests and complaints related to the East Line 2007 Index Tariff;

- FERC Docket No. IS07-234—Complainants/Protestants: BP WCP and ExxonMobil—Defendant: Calnev Calnev filed to increase certain rates on its pipeline pursuant to FERC's indexing methodology. Two shippers protested. The FERC found the tariff filings consistent with its regulations but suspended the increased rates subject to refund pending challenges to SFPP's underlying rates. Calnev and ExxonMobil have reached an agreement in principle to settle this and other dockets;

- FERC Docket No. IS08-28—Complainants/Protestants: ConocoPhillips; Chevron; BP WCP; ExxonMobil; Southwest Airlines; Western; and Valero—Defendant: SFPP
SFPP filed to increase its East Line rates based on costs incurred related to an expansion. Various shippers filed protests, which SFPP answered. The FERC issued an order on November 29, 2007 accepting and suspending the tariff subject to refund. The proceeding is being held in abeyance pursuant to ongoing settlement negotiations; and

- Motions to compel payment of interim damages (various dockets)—Complainants/Protestants: Shippers—Defendants: SFPP; Kinder Morgan G.P., Inc.; and Knight Inc.
Motions seek payment of interim refunds or escrow of funds pending resolution of various complaints and protests involving SFPP. The FERC denied shippers' refund requests in an order issued on December 26, 2007 in Docket Nos. OR92-8, *et al*.

In 2003, we made aggregate payments of $44.9 million for reparations and refunds pursuant to a FERC order related to Docket Nos. OR92-8, *et al*. In December 2005, SFPP received a FERC order in OR92-8 and OR96-2 that directed it to submit compliance filings and revised tariffs. In accordance with the FERC's December 2005 order and its February 2006 order on rehearing, SFPP submitted a compliance filing to the FERC in March 2006, and rate reductions were implemented on May 1, 2006. We estimate the impact of the rate reductions in 2007 was approximately $25 million, and we estimate that the actual, partial year impact on 2006 distributable cash flow was approximately $15.7 million. In addition, in December 2005, we recorded accruals of $105.0 million for expenses attributable to an increase in our reserves related to our rate case liability.

In December 2007, as a follow-up to the March 2006 compliance filing, SFPP received a FERC order that directed us to submit revised compliance filings and revised tariffs. In conjunction with this order, our other FERC and CPUC rate cases, and other unrelated litigation matters, we increased our litigation reserves by $140.0 million in the fourth quarter of 2007. We assume that, with respect to our SFPP litigation reserves, any additional reparations and accrued interest thereon will be paid no earlier than the fourth quarter of 2008. We expect to file the revised compliance filings on February 26, 2008, and to implement new rates on March 1, 2008. We estimate that the impact of the new rates on our 2008 budget will be less than $3.0 million.

In general, if the shippers are successful in proving their claims, they are entitled to reparations or refunds of any excess tariffs or rates paid during the two year period prior to the filing of their complaint, and our Pacific operations may be required to reduce the amount of its tariffs or rates for particular services. These proceedings tend to be protracted, with decisions of the FERC often appealed to the federal courts. Based on our review of these FERC proceedings, we estimate that shippers are seeking approximately $290 million in reparation and refund payments and approximately $45 million in additional annual rate reductions.

California Public Utilities Commission Proceedings

On April 7, 1997, ARCO, Mobil and Texaco filed a complaint against SFPP with the California Public Utilities Commission, referred to in this note as the CPUC. The complaint challenges rates charged by SFPP for intrastate transportation of refined petroleum products through its pipeline system in the state of California and requests prospective rate adjustments.

In October 2002, the CPUC issued a resolution, referred to in this note as the Power Surcharge Resolution, approving a 2001 request by SFPP to raise its California rates to reflect increased power costs. The resolution approving the requested rate increase also required SFPP to submit cost data for 2001, 2002, and 2003, and to assist the CPUC in determining whether SFPP's overall rates for California intrastate transportation services are reasonable. The resolution reserves the right to require refunds, from the date of issuance of the resolution, to the extent the CPUC's analysis of cost data to be submitted by SFPP demonstrates that SFPP's California jurisdictional rates are unreasonable in any fashion.

On December 26, 2006, Tesoro filed a complaint challenging the reasonableness of SFPP's intrastate rates for the three-year period from December 2003 through December 2006 and requesting approximately $8 million in reparations. As a result of previous SFPP rate filings and related protests, the rates that are the subject of the Tesoro complaint are being collected subject to refund.

SFPP also has various, pending ratemaking matters before the CPUC that are unrelated to the above-referenced complaints and the Power Surcharge Resolution. Protests to these rate increase applications have been filed by various shippers. As a consequence of the protests, the related rate increases are being collected subject to refund.

All of the above matters have been consolidated and assigned to a single administrative law judge. At the time of this report, it is unknown when a decision from the CPUC regarding the CPUC complaints and the Power Surcharge Resolution will be received. No schedule has been established for hearing and resolution of the consolidated proceedings other than the 1997 CPUC complaint and the Power Surcharge Resolution. Based on our review of these CPUC proceedings, we estimate that shippers are seeking approximately $100 million in reparation and refund payments and approximately $35 million in annual rate reductions.

Carbon Dioxide Litigation

Shores and First State Bank of Denton Lawsuits

Kinder Morgan CO_2 Company, L.P. (referred to in this note as Kinder Morgan CO_2), Kinder Morgan G.P., Inc., and Cortez Pipeline Company were among the named defendants in Shores, et al. v. Mobil Oil Corp., et al., No. GC-99-01184 (Statutory Probate Court, Denton County, Texas filed December 22, 1999) and First State Bank of Denton, et al. v. Mobil Oil Corp., et al., No. 8552-01 (Statutory Probate Court, Denton County, Texas filed March 29, 2001). These cases were originally filed as class actions on behalf of classes of overriding royalty interest owners (Shores) and royalty interest owners (Bank of Denton) for damages relating to alleged underpayment of royalties on carbon dioxide produced from the McElmo Dome Unit. On February 22, 2005, the trial judge dismissed both cases for lack of jurisdiction. Some of the individual plaintiffs in these cases re-filed their claims in new lawsuits (discussed below).

Armor/Reddy Lawsuit

On May 13, 2004, William Armor filed a case alleging the same claims for underpayment of royalties on carbon dioxide produced from the McElmo Dome Unit against Kinder Morgan CO_2, Kinder Morgan G.P., Inc., and Cortez Pipeline Company among others. *Armor v. Shell Oil Company, et al,* No. 04-03559 (14th Judicial District Court, Dallas County, Texas filed May 13, 2004).

On May 20, 2005, Josephine Orr Reddy and Eastwood Capital, Ltd. filed a case in Dallas state district court alleging the same claims for underpayment of royalties. *Reddy and Eastwood Capital, Ltd. v. Shell Oil Company, et al.*, No. 05-5021 (193rd Judicial District Court, Dallas County, Texas filed May 20, 2005). The defendants included Kinder Morgan CO_2 and Kinder Morgan Energy Partners, L.P. On June 23, 2005, the plaintiff in the Armor lawsuit filed a motion to transfer and consolidate the Reddy lawsuit with the Armor lawsuit. On June 28, 2005, the court in the Armor lawsuit ordered that the Reddy lawsuit be transferred and consolidated into the Armor lawsuit.

Effective March 5, 2007, the parties executed a final settlement agreement which providesfor the dismissal of the lawsuit and the plaintiffs' claims with prejudice to being refiled. On June 12, 2007, the Dallas state district court signed its order dismissing the case and all claims with prejudice.

Gerald O. Bailey et al. v. Shell Oil Co. et al/Southern District of Texas Lawsuit

Kinder Morgan CO_2, Kinder Morgan Energy Partners, L.P. and Cortez Pipeline Company are among the defendants in a proceeding in the federal courts for the southern district of Texas. *Gerald O. Bailey et al. v. Shell Oil Company et al.*, (Civil Action Nos. 05-1029 and 05-1829 in the U.S. District Court for the Southern District of Texas—consolidated by Order dated July 18, 2005). The plaintiffs are asserting claims for the underpayment of royalties on carbon dioxide produced from the McElmo Dome unit. The plaintiffs assert claims for fraud/fraudulent inducement, real estate fraud, negligent misrepresentation, breach of fiduciary and agency duties, breach of contract and covenants, violation of the Colorado Unfair Practices Act, civil theft under Colorado law, conspiracy, unjust enrichment, and open account. Plaintiffs Gerald O. Bailey, Harry Ptasynski, and W.L. Gray & Co. have also asserted claims as private relators under the False Claims Act and for violation of federal and Colorado antitrust laws. The plaintiffs seek actual damages, treble damages, punitive damages, a constructive trust and accounting, and declaratory relief. The defendants have filed motions for summary judgment on all claims. No trial date has been set.

Effective March 5, 2007, all defendants and plaintiffs Bridwell Oil Company, the Alicia Bowdle Trust, and the Estate of Margaret Bridwell Bowdle executed a final settlement agreement which provides for the dismissal of these plaintiffs' claims with prejudice to being refiled. On June 10, 2007, the Houston federal district court entered an order of partial dismissal by which the claims by and against the settling plaintiffs were dismissed with prejudice. The claims asserted by Bailey, Ptasynski, and Gray are not included within the settlement or the order of partial dismissal.

Ptasynski Colorado Federal District Court Lawsuit

On April 7, 2006, Harry Ptasynski, one of the plaintiffs in the Bailey action discussed above, filed suit against Kinder Morgan G.P., Inc. in Colorado federal district court. Harry Ptasynski v. Kinder Morgan G.P., Inc., No. 06-CV-00651 (LTB) (U.S. District Court for the District of Colorado). Ptasynski, who holds an overriding royalty interest at McElmo Dome, asserted claims for civil conspiracy, violation of the Colorado Organized Crime Control Act, violation of Colorado antitrust laws, violation of the Colorado Unfair Practices Act, breach of fiduciary duty and confidential relationship, violation of the Colorado Payment of Proceeds Act, fraudulent concealment, breach of contract and implied duties to market and good faith and fair dealing, and civil theft and conversion. Ptasynski sought actual damages, treble damages, forfeiture, disgorgement, and declaratory and injunctive relief. The Colorado court transferred the case to Houston federal district court, and Ptasynski voluntarily dismissed the case on May 19, 2006. Ptasynski also filed an appeal in the Tenth Circuit seeking to overturn the Colorado court's order transferring the case to Houston federal district court. Harry Ptasynski v. Kinder Morgan G.P., Inc., No. 06-1231 (10th Cir.). Briefing in the appeal was completed on November 27, 2006. On April 4, 2007, the Tenth Circuit Court of Appeals dismissed the appeal as moot in light of Ptasynksi's voluntary dismissal of the case.

Bridwell Oil Company Wichita County Lawsuit

On March 1, 2004, Bridwell Oil Company, one of the named plaintiffs in the above described Bailey action, filed a new matter in which it asserted claims that are virtually identical to the claims it asserted in the Bailey lawsuit. Bridwell Oil Co. v. Shell Oil Co. et al., No. 160,199-B (78th Judicial District Court, Wichita County, Texas filed March 1, 2004). The defendants in this action include, among others, Kinder Morgan CO_2, Kinder Morgan Energy Partners, L.P., and Cortez Pipeline Company. This case was abated pending resolution of the Bailey action discussed above.

Effective March 5, 2007, the parties executed a final settlement agreement which provides for the dismissal of the lawsuit and the plaintiffs' claims with prejudice to being refiled. On June 14, 2007, the Wichita County state district court signed its order dismissing the case and all claims with prejudice.

CO_2 Claims Arbitration

Cortez Pipeline Company and Kinder Morgan CO_2, successor to Shell CO_2 Company, Ltd., were among the named defendants in CO_2 Committee, Inc. v. Shell Oil Co., et al., an arbitration initiated on November 28, 2005. The arbitration arose from a dispute over a class action settlement agreement which became final on July 7, 2003 and disposed of five lawsuits formerly pending in the U.S. District Court, District of Colorado. The plaintiffs in such lawsuits primarily included overriding royalty interest owners, royalty interest owners, and small share working interest owners who alleged underpayment of royalties and other payments on carbon dioxide produced from the McElmo Dome Unit. The settlement imposed certain future obligations on the defendants in the underlying litigation. The plaintiff in the arbitration is an entity that was formed as part of the settlement for the purpose of monitoring compliance with the obligations imposed by the settlement agreement. The plaintiff alleged that, in calculating royalty and other payments, defendants used a transportation expense in excess of what is allowed by the settlement agreement, thereby causing alleged underpayments of approximately $12 million. The plaintiff also alleged that Cortez Pipeline Company should have used certain funds to further reduce its debt, which, in turn, would have allegedly increased the value of royalty and other payments by approximately $0.5 million. Defendants denied that there was any breach of the settlement agreement. On August 7, 2006, the arbitration panel issued its opinion finding that defendants did not breach the settlement agreement. On October 25, 2006, the defendants filed an application to confirm the arbitration decision in New Mexico federal district court. On June 21, 2007, the New Mexico federal district court entered final judgment confirming the August 7, 2006 arbitration decision.

On October 2, 2007, the plaintiff initiated a second arbitration (CO_2 Committee, Inc. v. Shell CO_2 Company, Ltd., aka Kinder Morgan CO_2Company, L.P., et al.) against Cortez Pipeline Company, Kinder Morgan CO_2 and a Mobil entity. The second arbitration asserts claims similar to those asserted in the first arbitration. On October 11, 2007, the defendants filed a Complaint for Declaratory Judgment and Injunctive Relief in federal district court in New Mexico. The Complaint seeks dismissal of the second arbitration on the basis of res judicata. In November 2007, the plaintiff in the arbitration moved to dismiss the defendants' Complaint on the grounds that the issues presented should be decided by a panel in a second arbitration. In December 2007, the defendants in the arbitration filed a motion seeking summary judgment on their Complaint and dismissal of the second arbitration. No hearing date has been set.

MMS Notice of Noncompliance and Civil Penalty

On December 20, 2006, Kinder Morgan CO_2 received a "Notice of Noncompliance and Civil Penalty: Knowing or Willful Submission of False, Inaccurate, or Misleading Information—Kinder Morgan CO_2 Company, L.P., Case No. CP07-001" from the U.S. Department of the Interior, Minerals Management Service. This Notice, and the MMS' position that Kinder Morgan CO_2 has violated certain reporting obligations, relates to a disagreement between the MMS and Kinder Morgan CO_2 concerning the approved transportation allowance to be used in valuing McElmo Dome carbon dioxide for purposes of calculating federal royalties. The Notice of Noncompliance and Civil Penalty assesses a civil penalty of approximately $2.2 million as of December 15, 2006 (based on a penalty of $500.00 per day for each of 17 alleged violations) for Kinder Morgan CO_2's alleged submission of false, inaccurate, or misleading information relating to the transportation allowance, and federal royalties for CO_2 produced at McElmo Dome, during the period from June 2005 through October 2006. The MMS contends that false, inaccurate, or misleading information was submitted in the 17 monthly Form 2014s containing remittance advice reflecting the royalty payments for the referenced period because they reflected Kinder Morgan CO_2's use of the Cortez Pipeline tariff as the transportation allowance. The MMS claims that the Cortez Pipeline tariff is not the proper transportation allowance and that Kinder Morgan CO_2 should have used its "reasonable actual costs" calculated in accordance with certain federal product valuation regulations as amended effective June 1, 2005. The MMS stated that civil penalties will continue to accrue at the same rate until the alleged violations are corrected.

The MMS set a due date of January 20, 2007 for Kinder Morgan CO_2's payment of the approximately $2.2 million in civil penalties, with interest to accrue daily on that amount in the event payment is not made by such date. Kinder Morgan CO_2has not paid the penalty. On January 2, 2007, Kinder Morgan CO_2 submitted a response to the Notice of Noncompliance and Civil Penalty challenging the assessment in the Office of Hearings and Appeals of the Department of the Interior. On February 1, 2007, Kinder Morgan CO_2 filed a petition to stay the accrual of penalties until the dispute is resolved. On February 22, 2007, an administrative law judge of the U.S. Department of the Interior issued an order denying Kinder Morgan CO_2's petition to stay the accrual of penalties. A hearing on the Notice of Noncompliance and Civil Penalty was originally set for December 10, 2007. In November 2007, the MMS and Kinder Morgan CO_2 filed a joint motion to vacate the hearing date and stay the accrual of additional penalties to allow the parties to discuss settlement. In November 2007, the administrative law judge granted the joint motion, stayed accrual of additional penalties for the period from November 6, 2007 to February 18, 2008, and reset the hearing date to March 24, 2008. The parties conducted settlement conferences on February 4, 2008 and February 12, 2008.

Kinder Morgan CO_2 disputes the Notice of Noncompliance and Civil Penalty and believes that it has meritorious defenses. Kinder Morgan CO_2 contends that use of the Cortez pipeline tariff as the transportation allowance for purposes of calculating federal royalties was approved by the MMS in 1984. This approval was later affirmed as open-ended by the Interior Board of Land Appeals in the 1990s. Accordingly, Kinder Morgan CO_2 has stated to the MMS that its use of the Cortez tariff as the approved federal transportation allowance is authorized and proper. Kinder Morgan CO_2 also disputes the allegation that it has knowingly or willfully submitted false, inaccurate, or misleading information to the MMS. Kinder MorganCO_2's use of the Cortez Pipeline tariff as the approved federal transportation allowance has been the subject of extensive discussion between the parties. The MMS was, and is, fully apprised of that fact and of the royalty valuation and payment process followed by Kinder Morgan CO_2 generally.

MMS Order to Report and Pay

On March 20, 2007, Kinder Morgan CO_2 received an "Order to Report and Pay" from the Minerals Management Service. The MMS contends that Kinder Morgan CO*2* has over-reported transportation allowances and underpaid royalties in the amount of approximately $4.6 million for the period from January 1, 2005 through December 31, 2006 as a result of its use of the Cortez pipeline tariff as the transportation allowance in calculating federal royalties. As noted in the discussion of the Notice of Noncompliance and Civil Penalty proceeding, the MMS claims that the Cortez Pipeline tariff is not the proper transportation allowance and that Kinder Morgan CO_2 must use its "reasonable actual costs" calculated in accordance with certain federal product valuation regulations. The MMS set a due date of April 13, 2007 for Kinder Morgan CO_2's payment of the $4.6 million in claimed additional royalties, with possible late payment charges and civil penalties for failure to pay the assessed amount. Kinder Morgan CO_2 has not paid the $4.6 million, and on April 19, 2007, it submitted a notice of appeal and statement of reasons in response to the Order to Report and Pay, challenging the Order and appealing it to the Director of the MMS in accordance with 30 CFR 290.100, et seq. Also on April 19, 2007, Kinder Morgan CO_2 submitted a petition to suspend compliance with the Order to Report and Pay pending the appeal. The MMS granted Kinder Morgan CO_2's petition to suspend, and approved self-bonding on June 12, 2007. Kinder Morgan CO_2 filed a supplemental statement of reasons in support of its appeal of the Order to Report and Pay on June 15, 2007.

In addition to the March 2007 Order to Report and Pay, in April 2007, Kinder Morgan CO_2 received an "Audit Issue Letter" sent by the Colorado Department of Revenue on behalf of the U.S. Department of the Interior. In the letter, the Department of Revenue states that Kinder Morgan CO_2 has over-reported transportation allowances and underpaid royalties (due to the use of the Cortez pipeline tariff as the transportation allowance for purposes of federal royalties) in the amount of $8.5 million for the period from April 2000 through December 2004. Kinder Morgan CO_2 responded to the letter in May 2007, outlining its position why use of the Cortez tariff-based transportation allowance is proper. On August 8, 2007, Kinder Morgan CO_2 received an "Order to Report and Pay Additional Royalties" from the MMS. As alleged in the Colorado Audit Issue Letter, the MMS contends that Kinder Morgan CO_2 has over-reported transportation allowances and underpaid royalties in the amount of approximately $8.5 million for the period from April 2000 through December 2004. The MMS's claims underlying the August 2007 Order to Report and Pay are similar to those at issue in the March 2007 Order to Report and Pay. On September 7, 2007, Kinder Morgan CO_2 submitted a notice of appeal and statement of reasons in response to the August 2007 Order to Report and Pay, challenging the Order and appealing it to the Director of the MMS in accordance with 30 CFR 290.100, et seq. Also on September 7, 2007, Kinder Morgan CO_2 submitted a petition to suspend compliance with the Order to Report and Pay pending the appeal. The MMS granted Kinder Morgan CO_2's petition to suspend, and approved self-bonding on September 11, 2007.

The MMS and Kinder Morgan CO_2 have agreed to stay the March 2007 and August 2007 Order to Report and Pay proceedings to allow the parties to discuss settlement. The parties conducted settlement conferences on February 4, 2008 and February 12, 2008.

Kinder Morgan CO_2 disputes both the March and August 2007 Orders to Report and Pay and the Colorado Department of Revenue Audit Issue Letter, and as noted above, it contends that use of the Cortez pipeline tariff as the transportation allowance for purposes of calculating federal royalties was approved by the MMS in 1984 and was affirmed as open-ended by the Interior Board of Land Appeals in the 1990s. The appeals to the MMS Director of the Orders to Report and Pay do not provide for an oral hearing. No further submission or briefing deadlines have been set.

J. Casper Heimann, Pecos Slope Royalty Trust and Rio Petro LTD, individually and on behalf of all other private royalty and overriding royalty owners in the Bravo Dome Carbon Dioxide Unit, New Mexico similarly situated v. Kinder Morgan CO_2 Company, L.P., No. 04-26-CL (8th Judicial District Court, Union County New Mexico)

This case involves a purported class action against Kinder Morgan CO_2 alleging that it has failed to pay the full royalty and overriding royalty ("royalty interests") on the true and proper settlement value of compressed carbon dioxide produced from the Bravo Dome Unit during the period beginning January 1, 2000. The complaint purports to assert claims for violation of the New Mexico Unfair Practices Act, constructive fraud, breach of contract and of the covenant of good faith and fair dealing, breach of the implied covenant to market, and claims for an accounting, unjust enrichment, and injunctive relief. The purported class is comprised of current and former owners, during the period January 2000 to the present, who have private property royalty interests burdening the oil and gas leases held by the defendant, excluding the Commissioner of Public Lands, the United States of America, and those private royalty interests that are not unitized as part of the Bravo Dome Unit. The plaintiffs allege that they were members of a class previously certified as a class action by the United States District Court for the District of New Mexico in the matter Doris Feerer, et al. v. Amoco Production Company, et al., USDC N.M. Civ. No. 95-0012 (the "Feerer Class Action"). Plaintiffs allege that Kinder Morgan CO_2's method of paying royalty interests is contrary to the settlement of the Feerer Class Action. Kinder Morgan CO_2 filed a motion to compel arbitration of this matter pursuant to the arbitration provisions contained in the Feerer Class Action settlement agreement, which motion was denied. Kinder Morgan CO_2 appealed this decision to the New Mexico Court of Appeals, which affirmed the decision of the trial court. The New Mexico Supreme Court granted further review in October 2006, and after hearing oral argument, the New Mexico Supreme Court quashed its prior order granting review. In August 2007, Kinder Morgan CO_2 filed a petition for writ of certiorari with the United States Supreme Court seeking further review. The Petition was denied in December 2007. The case is now proceeding in the trial court as a certified class action and the case is set for trial in September 2008.

In addition to the matters listed above, audits and administrative inquiries concerning Kinder Morgan CO_2's payments on carbon dioxide produced from the McElmo Dome and Bravo Dome Units are currently ongoing. These audits and inquiries involve federal agencies and the States of Colorado and New Mexico.

Commercial Litigation Matters

Union Pacific Railroad Company Easements

SFPP, L.P. and Union Pacific Railroad Company (the successor to Southern Pacific Transportation Company and referred to in this Note as UPRR) are engaged in a proceeding to determine the extent, if any, to which the rent payable by SFPP for the use of pipeline easements on rights-of-way held by UPRR should be adjusted pursuant to existing contractual arrangements for the ten year period beginning January 1, 2004 (*Union Pacific Railroad Company vs. Santa Fe Pacific Pipelines, Inc., SFPP, L.P., Kinder Morgan Operating L.P. "D", Kinder Morgan G.P., Inc., et al.*, Superior Court of the State of California for the County of Los Angeles, filed July 28, 2004). In February 2007, a trial began to determine the amount payable for easements on UPRR rights-of-way. The trial is ongoing and is expected to conclude in the second quarter of 2008.

SFPP and UPRR are also engaged in multiple disputes over the circumstances under which SFPP must pay for a relocation of its pipeline within the UPRR right of way and the safety standards that govern relocations. SFPP believes that it must pay for relocation of the pipeline only when so required by the railroad's common carrier operations, and in doing so, it need only comply with standards set forth in the federal Pipeline Safety Act in conducting relocations. In July 2006, a trial before a judge regarding the circumstances under which we must pay for relocations concluded, and the judge determined that we must pay for any relocations resulting from any legitimate business purpose of the UPRR. We have appealed this decision. In addition, UPRR contends that it has complete discretion to cause the pipeline to be relocated at SFPP's expense at any time and for any reason, and that SFPP must comply with the more expensive American Railway Engineering and Maintenance-of-Way standards. Each party is seeking declaratory relief with respect to its positions regarding relocations.

It is difficult to quantify the effects of the outcome of these cases on SFPP because SFPP does not know UPRR's plans for projects or other activities that would cause pipeline relocations. Even if SFPP is successful in advancing its positions, significant relocations for which SFPP must nonetheless bear the expense (i.e. for railroad purposes, with the standards in the federal Pipeline Safety Act applying) would have an adverse effect on our financial position and results of operations. These effects would be even greater in the event SFPP is unsuccessful in one or more of these litigations.

United States of America, ex rel., Jack J. Grynberg v. K N Energy (Civil Action No. 97-D-1233, filed in the U.S. District Court, District of Colorado).

This multi-district litigation proceeding involves four lawsuits filed in 1997 against numerous Kinder Morgan companies. These suits were filed pursuant to the federal False Claims Act and allege underpayment of royalties due to mismeasurement of natural gas produced from federal and Indian lands. The complaints are part of a larger series of similar complaints filed by Mr. Grynberg against 77 natural gas pipelines (approximately 330 other defendants) in various courts throughout the country which were consolidated and transferred to the District of Wyoming.

In May 2005, a Special Master appointed in this litigation found that because there was a prior public disclosure of the allegations and that Grynberg was not an original source, the Court lacked subject matter jurisdiction. As a result, the Special Master recommended that the Court dismiss all the Kinder Morgan defendants. In October 2006, the United States District Court for the District of Wyoming upheld the dismissal of each case against the Kinder Morgan defendants on jurisdictional grounds. Grynberg has appealed this Order to the Tenth Circuit Court of Appeals. A procedural schedule has been issued and briefing before the Court of Appeals will be completed in the spring of 2008. The oral argument is expected to take place in September 2008.

Prior to the dismissal order on jurisdictional grounds, the Kinder Morgan defendants filed Motions to Dismiss and for Sanctions alleging that Grynberg filed his Complaint without evidentiary support and for an improper purpose. On January 8, 2007, after the dismissal order, the Kinder Morgan defendants also filed a Motion for Attorney Fees under the False Claim Act. On April 24, 2007 the Court held a hearing on the Motions to Dismiss and for Sanctions and the Requests for Attorney Fees. A decision is still pending on the Motions to Dismiss and for Sanctions and the Requests for Attorney Fees.

Weldon Johnson and Guy Sparks, individually and as Representative of Others Similarly Situated v. Centerpoint Energy, Inc. et. al., No. 04-327-2 (Circuit Court, Miller County Arkansas).

On October 8, 2004, plaintiffs filed the above-captioned matter against numerous defendants including Kinder Morgan Texas Pipeline L.P.; Kinder Morgan Energy Partners, L.P.; Kinder Morgan G.P., Inc.; KM Texas Pipeline, L.P.; Kinder Morgan Texas Pipeline G.P., Inc.; Kinder Morgan Tejas Pipeline G.P., Inc.; Kinder Morgan Tejas Pipeline, L.P.; Gulf Energy Marketing, LLC; Tejas Gas, LLC; and MidCon Corp. (the "Kinder Morgan defendants"). The complaint purports to bring a class action on behalf of those who purchased natural gas from the CenterPoint defendants from October 1, 1994 to the date of class certification.

The complaint alleges that CenterPoint Energy, Inc., by and through its affiliates, has artificially inflated the price charged to residential consumers for natural gas that it allegedly purchased from the non-CenterPoint defendants, including the Kinder Morgan defendants. The complaint further alleges that in exchange for CenterPoint’s purchase of such natural gas at above market prices, the non-CenterPoint defendants, including the Kinder Morgan defendants, sell natural gas to CenterPoint’s non-regulated affiliates at prices substantially below market, which in turn sells such natural gas to commercial and industrial consumers and gas marketers at market price. The complaint purports to assert claims for fraud, unlawful enrichment and civil conspiracy against all of the defendants, and seeks relief in the form of actual, exemplary and punitive damages, interest, and attorneys’ fees. On June 8, 2007, the Arkansas Supreme Court held that the Arkansas Public Service Commission has exclusive jurisdiction over any Arkansas plaintiffs’ claims that consumers were overcharged for gas in Arkansas and mandated that any such claims be dismissed from this lawsuit. On February 14, 2008, the Arkansas Supreme Court clarified its previously issued order and mandated that the trial court dismiss the lawsuit in its entirety. Based on the information available to date and our preliminary investigation, the Kinder Morgan defendants believe that the claims against them are without merit and intend to defend against them vigorously.

Federal Investigation at Cora and Grand Rivers Coal Facilities

On June 22, 2005, we announced that the Federal Bureau of Investigation was conducting an investigation related to our coal terminal facilities located in Rockwood, Illinois and Grand Rivers, Kentucky. The investigation involved certain coal sales from our Cora, Illinois and Grand Rivers, Kentucky coal terminals that occurred from 1997 through 2001. During this time period, we sold excess coal from these two terminals for our own account, generating less than $15 million in total net sales. Excess coal is the weight gain that results from moisture absorption into existing coal during transit or storage and from scale inaccuracies, which are typical in the industry. During the years 1997 through 1999, we collected, and, from 1997 through 2001, we subsequently sold, excess coal for our own account, as we believed we were entitled to do under then-existing customer contracts. We conducted an internal investigation of the allegations and discovered no evidence of wrongdoing or improper activities at these two terminals.

In the fourth quarter of 2007, we reached a civil settlement with the U.S. Attorney’s office for the Southern District of Illinois pursuant to which we paid approximately $25 million, in aggregate, to the Tennessee Valley Authority and other customers of the Cora and Grand Rivers terminals from 1997 through 1999. We made no admission or acknowledgment of improper conduct as part of the settlement, and while we continue to believe that our actions at our terminals were appropriate, we determined that a civil resolution of the matter would be in our best interest. The settlement has been finalized, and we recorded a $25 million increase in expense in the third quarter of 2007 associated with the settlement of this liability.

Queen City Railcar Litigation

On August 28, 2005, a railcar containing the chemical styrene began leaking styrene gas in Cincinnati, Ohio while en route to our Queen City Terminal. The railcar was sent by the Westlake Chemical Corporation from Louisiana, transported by Indiana & Ohio Railway, and consigned to Westlake at its dedicated storage tank at Queen City Terminals, Inc., a subsidiary of Kinder Morgan Bulk Terminals, Inc. The railcar leak resulted in the evacuation of many residents and the alleged temporary closure of several businesses in the Cincinnati area. A class action complaint and a suit filed by the City of Cincinnati arising out of this accident have been settled. However, one member of the settlement class, the Estate of George W. Dameron, opted out of the settlement, and the Adminstratrix of the Dameron Estate filed a wrongful death lawsuit on November 15, 2006 in the Hamilton County Court of Common Pleas, Case No. A0609990. The complaint, which is asserted against each of the defendants involved in the class action suit, alleges that styrene exposure caused the death of Mr. Dameron. Without admitting fault or liability, the parties have reached a settlement in principle of the Dameron suit.

As part of the settlement of the class action claims, the non-Kinder Morgan defendants have agreed to settle remaining claims asserted by businesses and will obtain a release of such claims favoring all defendants, including Kinder Morgan and its affiliates, subject to the retention by all defendants of their claims against each other for contribution and indemnity. Kinder Morgan expects that a claim will be asserted by other defendants against Kinder Morgan seeking contribution or indemnity for any settlements funded exclusively by other defendants, and Kinder Morgan expects to vigorously defend against any such claims.

Leukemia Cluster Litigation

Richard Jernee, et al v. Kinder Morgan Energy Partners, et al, No. CV03-03482 (Second Judicial District Court, State of Nevada, County of Washoe) ("Jernee").

Floyd Sands, et al v. Kinder Morgan Energy Partners, et al, No. CV03-05326 (Second Judicial District Court, State of Nevada, County of Washoe) ("Sands").

On May 30, 2003, plaintiffs, individually and on behalf of Adam Jernee, filed a civil action in the Nevada State trial court against us and several Kinder Morgan related entities and individuals and additional unrelated defendants. Plaintiffs in the Jernee matter claim that defendants negligently and intentionally failed to inspect, repair and replace unidentified segments of their pipeline and facilities, allowing "harmful substances and emissions and gases" to damage "the environment and health of human beings." Plaintiffs claim that "Adam Jernee's death was caused by leukemia that, in turn, is believed to be due to exposure to industrial chemicals and toxins." Plaintiffs purport to assert claims for wrongful death, premises liability, negligence, negligence per se, intentional infliction of emotional distress, negligent infliction of emotional distress, assault and battery, nuisance, fraud, strict liability (ultra hazardous acts), and aiding and abetting, and seek unspecified special, general and punitive damages. On August 28, 2003, a separate group of plaintiffs, represented by the counsel for the plaintiffs in the Jernee matter, individually and on behalf of Stephanie Suzanne Sands, filed a civil action in the Nevada State trial court against the same defendants and alleging the same claims as in the Jernee case with respect to Stephanie Suzanne Sands. The Jernee case has been consolidated for pretrial purposes with the Sands case. In May 2006, the court granted defendants' motions to dismiss as to the counts purporting to assert claims for fraud, but denied defendants' motions to dismiss as to the remaining counts, as well as defendants' motions to strike portions of the complaint. Defendant Kennametal, Inc. has filed a third-party complaint naming the United States and the United States Navy (the "United States") as additional defendants. In response, the United States removed the case to the United States District Court for the District of Nevada and filed a motion to dismiss the third-party complaint. Plaintiff has also filed a motion to dismiss the United States and/or to remand the case back to state court. By order dated September 25, 2007, the United States District Court granted the motion to dismiss the United States from the case and remanded the Jernee and Sands cases back to the Second Judicial District Court, State of Nevada, County of Washoe. The cases will now proceed in the State Court. Based on the information available to date, our own preliminary investigation, and the positive results of investigations conducted by State and Federal agencies, we believe that the remaining claims against us in these matters are without merit and intend to defend against them vigorously.

Pipeline Integrity and Releases

From time to time, our pipelines experience leaks and ruptures. These leaks and ruptures may cause explosions, fire, damage to the environment, damage to property and/or personal injury or death. In connection with these incidents, we may be sued for damages caused by an alleged failure to properly mark the locations of our pipelines and/or to properly maintain our pipelines. Depending upon the facts and circumstances of a particular incident, state and federal regulatory authorities may seek civil and/or criminal fines and penalties.

We believe that we conduct our operations in accordance with applicable law. We seek to cooperate with state and federal regulatory authorities in connection with the clean-up of the environment caused by such leaks and ruptures and with any investigations as to the facts and circumstances surrounding the incidents.

Kleberg County, Texas Gas Pipeline Rupture

On February 12, 2008, Kinder Morgan Texas Pipeline incurred a failure on its 16-inch diameter natural gas pipeline in a remote area in Kleberg County, Texas, which resulted in an explosion and fire. The incident caused some property damage, however no serious physical injuries have been reported to date. Kinder Morgan Texas Pipeline notified appropriate regulatory agencies and is currently investigating the cause of the rupture.

Walnut Creek, California Pipeline Rupture

On November 9, 2004, excavation equipment operated by Mountain Cascade, Inc., a third-party contractor on a water main installation project hired by East Bay Municipal Utility District, struck and ruptured an underground petroleum pipeline owned and operated by SFPP, L.P. in Walnut Creek, California. An explosion occurred immediately following the rupture that resulted in five fatalities and several injuries to employees or contractors of Mountain Cascade. The explosion and fire also caused property damage.

On May 5, 2005, the California Division of Occupational Safety and Health ("CalOSHA") issued two civil citations against us relating to this incident assessing civil fines of approximately $0.1 million based upon our alleged failure to mark the location of the pipeline properly prior to the excavation of the site by the contractor. On June 27, 2005, the Office of the California State Fire Marshal, Pipeline Safety Division, referred to in this report as the CSFM, issued a notice of violation against us which also alleged that we did not properly mark the location of the pipeline in violation of state and federal regulations. The CSFM assessed a proposed civil penalty of $0.5 million. The location of the incident was not our work site, nor did we have any direct involvement in the water main replacement project. We believe that SFPP acted in accordance with applicable law and regulations, and further that according to California law, excavators, such as the contractor on the project, must take the necessary steps (including excavating with hand tools) to confirm the exact location of a pipeline before using any power operated or power driven excavation equipment. Accordingly, we disagree with certain of the findings of CalOSHA and the CSFM, and we have appealed the civil penalties while, at the same time, continuing to work cooperatively with CalOSHA and the CSFM to resolve these matters.

On September 21, 2007, KMGP Services Company, Inc., an affiliate of Knight, entered into a plea agreement and civil settlement with the District Attorney of Contra Costa County pertaining to this accident. Under the terms of the plea agreement, KMGP Services Company, Inc. agreed to plead no contest to six counts of violating the California Labor Code. While initially constituted as felonies under the California Labor Code, the plea agreement contemplates that following the successful completion of an independent audit of our right-of-way protection policies and practices (likely in approximately one year), we may move to reduce the felony counts to misdemeanors. Pursuant to the plea agreement and civil settlement, in October 2007, we paid approximately $15 million.

As a result of the accident, nineteen separate lawsuits were filed. The majority of the cases were personal injury and wrongful death actions that alleged, among other things, that SFPP/Kinder Morgan failed to properly field mark the area where the accident occurred.

Following court ordered mediation, the Kinder Morgan defendants have settled with plaintiffs in all of the wrongful death cases and the personal injury and property damages cases. These settlements have either become final by order of the court or are awaiting court approval. The only civil cases which remain pending at present are: (i) a cross-claim for contribution and indemnity by an engineering company defendant against the Kinder Morgan defendants in which the court has entered summary judgment in favor of the Kinder Morgan defendants; and (ii) a challenge to the court-ordered allocation of settlement proceeds in one of the court-approved wrongful death settlements filed by a nonresident sibling in which the court has also granted summary judgment in favor of the Kinder Morgan defendants. Both of these judgments in favor of the Kinder Morgan defendants are subject to potential appeal.

Additionally, following this accident, we reviewed and when appropriate, revised our pipeline policies and procedures to improve safety. We have undertaken a number of actions to reduce future third-party damage to our pipelines, including adding line riders and locators, retaining third-party expertise, instituting enhanced line location training and education of employees and contractors, and investing in additional state-of-the-art line locating equipment. We have also committed to various procedural requirements pertaining to construction near our pipelines.

Consent Agreement Regarding Cordelia, Oakland and Donner Summit California Releases

On May 21, 2007, we and SFPP entered into a Consent Agreement with various governmental agencies to resolve civil claims relating to the unintentional release of petroleum products during three pipeline incidents in northern California. The releases occurred (i) in the Suisun Marsh area near Cordelia in Solano County, in April 2004; (ii) in Oakland in February 2005; and (iii) near Donner Pass in April 2005. The agreement was reached with the United States Environmental Protection Agency, referred to in this note as the EPA, Department of the Interior, Department of Justice and the National Oceanic and Atmospheric Administration, as well as the State of California Department of Fish and Game, Office of Spill Prevention and Response, and the Regional Water Quality Control Boards for the San Francisco and Lahontan regions. Under the Consent Agreement, we agreed to pay approximately $3.8 million in civil penalties, $1.3 million in natural resource damages and assessment costs and approximately $0.2 million in agency response and future remediation monitoring costs. All of the civil penalties have been reserved for as of September 30, 2007. In addition, we agreed to perform enhancements in our Pacific Operations relative to its spill prevention, response and reporting practices, the majority of which have already been implemented.

The Consent Agreement was filed with the United States District Court for the Eastern District of California on May 29, 2007 and became effective July 26, 2007. We have substantially completed remediation and restoration activities in consultation with the appropriate state and federal regulatory agencies at the location of each release.

EPA Notice of Proposed Debarment

On August 21, 2007, SFPP received a Notice of Proposed Debarment issued by the United States Environmental Protection Agency, referred to in this report as the EPA. Pursuant to the Notice, the Suspension and Debarment Division of the EPA is proposing to debar SFPP from participation in future Federal contracts and assistance activities for a period of three years. The purported basis for the proposed debarment is SFPP’s April, 2005 agreement with the California Attorney General and the District Attorney of Solano County, California to settle misdemeanor charges of the unintentional, non-negligent discharge of diesel fuel, and the failure to provide timely notice of a threatened discharge to appropriate state agencies, in connection with the April 28, 2004 spill of diesel fuel into a marsh near Cordelia, California. SFPP believes that the proposed debarment is factually and legally unwarranted and intends to contest it. In addition, SFPP is currently engaged in discussions with the EPA to attempt to resolve this matter. Based upon our discussions to date, we do not believe that this matter will result in the debarment or suspension of SFPP.

Baker, California

In November 2004, our CALNEV Pipeline experienced a failure from external damage near Baker, California, resulting in a release of gasoline that affected approximately two acres of land in the high desert administered by the U.S. Bureau of Land Management. Remediation has been conducted and continues for product in the soils. All agency requirements have been met and the site will be closed upon completion of the soil remediation. The

California Department of Fish & Game has alleged a small natural resource damage claim that is currently under review. CALNEV expects to work cooperatively with the Department of Fish & Game to resolve this claim.

Henrico County, Virginia

On April 17, 2006, Plantation Pipe Line Company, which transports refined petroleum products across the southeastern United States and which is 51.17% owned and operated by us, experienced a pipeline release of turbine fuel from its 12-inch pipeline. The release occurred in a residential area and impacted adjacent homes, yards and common areas, as well as a nearby stream. The released product did not ignite and there were no deaths or injuries. Plantation estimates the amount of product released to be approximately 553 barrels. Immediately following the release, the pipeline was shut down and emergency remediation activities were initiated. Remediation and monitoring activities are ongoing under the supervision of the EPA, and the Virginia Department of Environmental Quality, referred to in this report as VDEQ. Following settlement negotiations and discussions with VDEQ, Plantation and VDEQ entered into a Special Order on Consent under which Plantation agreed to pay a civil penalty of approximately $0.7 million to VDEQ as well as reimburse VDEQ for less than $0.1 million in expenses and oversight costs to resolve the matter. Plantation satisfied $0.2 million of the civil penalty by completing a supplemental environmental project in the form of a $0.2 million donation to the Henrico County Fire Department for the purchase of hazardous material spill response equipment.

Dublin, California

In June 2006, our SFPP pipeline experienced a leak near Dublin, California, resulting in a release of product that affected a limited area along a recreation path. We have completed remediation activities and have petitioned the California Regional Water Quality Control Board for closure. The cause of the release was outside force damage.

Soda Springs, California

In August 2006, our SFPP pipeline experienced a failure near Soda Springs, California, resulting in a release of product that affected a limited area along Interstate Highway 80. Product impacts were primarily limited to soil in an area between the pipeline and Interstate Highway 80. Remediation and monitoring activities are ongoing under the supervision of the California Department of Fish & Game and Nevada County. The cause of the release was determined to be pinhole corrosion in an unpiggable 2-inch diameter bypass to the mainline valve. The bypass was installed to allow pipeline maintenance activity. The bypass piping was replaced at this location and all other similar designs on the pipeline segment were excavated, evaluated and replaced as necessary to avoid future risk of release. On January 30, 2008, we entered into a settlement agreement with Nevada County and the state of California to resolve any outstanding civil penalties claims related to this release for $75,000.

Rockies Express Pipeline LLC Wyoming Construction Incident

On November 11, 2006, a bulldozer operated by an employee of Associated Pipeline Contractors, Inc, (a third-party contractor to Rockies Express Pipeline LLC, referred to in this Note as REX), struck an existing subsurface natural gas pipeline owned by Wyoming Interstate Company, a subsidiary of El Paso Pipeline Group. The pipeline was ruptured, resulting in an explosion and fire. The incident occurred in a rural area approximately nine miles southwest of Cheyenne, Wyoming. The incident resulted in one fatality (the operator of the bulldozer) and there were no other reported injuries. The cause of the incident is under investigation by the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration, referred to in this report as the PHMSA. We are cooperating with this agency. Immediately following the incident, REX and El Paso Pipeline Group reached an agreement on a set of additional enhanced safety protocols designed to prevent the reoccurrence of such an incident.

In September 2007, the family of the deceased bulldozer operator filed a wrongful death action against us, Rockies Express Pipeline LLC and several other parties in the District Court of Harris County, Texas, 189 Judicial District, at case number 2007-57916. The plaintiffs seek unspecified compensatory and exemplary damages plus interest, attorney’s fees and costs of suit. We have asserted contractual claims for complete indemnification for any and all costs arising from this incident, including any costs related to this lawsuit, against third parties and their insurers. The parties are currently engaged in discovery. We do not expect the cost of any settlement or eventual judgment, if any, to be material.

Charlotte, North Carolina

On November 27, 2006, the Plantation Pipeline experienced a release of approximately 4,000 gallons of gasoline from a Plantation Pipe Line Company block valve on a delivery line into a terminal owned by a third party company. Upon discovery of the release, Plantation immediately locked out the delivery of gasoline through that pipe to prevent further releases. Product had flowed onto the surface and into a nearby stream, which is a tributary of Paw Creek, and resulted in loss of fish and other biota. Product recovery and remediation efforts were implemented immediately, including removal of product from the stream. The line was repaired and put back into service within a few days. Remediation efforts are continuing under the direction of the North Carolina Department of Environment and Natural Resources (the "NCDENR"), which issued a Notice of Violation and Recommendation of Enforcement against Plantation on January 8, 2007. Plantation continues to cooperate fully with the NCDENR.

Although Plantation does not believe that penalties are warranted, it is engaging in settlement discussions with the EPA regarding a potential civil penalty for the November 2006 release as part of broader settlement negotiations with the EPA regarding this spill and two other historic releases from Plantation, including a February 2003 release near Hull, Georgia. Plantation has reached an agreement in principle with the Department of Justice and the EPA for all four releases for approximately $0.7 million, plus some additional work to be performed to prevent future releases. The parties are negotiating a consent decree. Although it is not possible to predict the ultimate outcome, we believe, based on our experiences to date, that the ultimate resolution of such items will not have a material adverse impact on our business, financial position, results of operations or cash flows.

In addition, in April 2007, during pipeline maintenance activities near Charlotte, North Carolina, Plantation discovered the presence of historical soil contamination near the pipeline, and reported the presence of impacted soils to the NCDENR. Subsequently, Plantation contacted the owner of the property to request access to the property to investigate the potential contamination. The results of that investigation indicate that there is soil and groundwater contamination which appears to be from an historical turbine fuel release. The groundwater contamination is underneath at least two lots on which there is current construction of single family homes as part of a new residential development. Further investigation and remediation are being conducted under the oversight of the NCDENR. Plantation is working with the owner of the property and the builder of the residential subdivision to address any potential claims that they may bring.

Barstow, California

The United States Department of Navy has alleged that historic releases of methyl tertiary-butyl ether, referred to in this report as MTBE, from CalNev Pipe Line Company’s Barstow terminal has (i) migrated underneath the Navy’s Marine Corps Logistics Base in Barstow; (ii) impacted the Navy’s existing groundwater treatment system for unrelated groundwater contamination not alleged to have been caused by CalNev, and (iii) could affect the MCLB’s water supply system. Although CalNev believes that it has certain meritorious defenses to the Navy’s claims, we are working with the Navy to agree upon an Administrative Settlement Agreement and Order on Consent for CERCLA Removal Action to reimburse the Navy for $0.5 million in past response actions, plus perform other work to ensure protection of the Navy’s existing treatment system and water supply.

Oil Spill Near Westridge Terminal, Burnaby, British Columbia

On July 24, 2007, a third-party contractor installing a sewer line for the City of Burnaby struck a crude oil pipeline segment included within our Trans Mountain pipeline system near its Westridge terminal in Burnaby, BC, resulting in a release of approximately 1,400 barrels of crude oil. The release impacted the surrounding neighborhood, several homes and nearby Burrard Inlet. No injuries were reported. To address the release, we initiated a comprehensive emergency response in collaboration with, among others, the City of Burnaby, the BC Ministry of Environment, the National Energy Board, and the National Transportation Safety Board. Cleanup and environmental remediation is continuing. The incident is currently under investigation by Federal and Provincial agencies. We do not expect this matter to have a material adverse impact on our results of operations or cash flows.

On December 20, 2007 we initiated a lawsuit entitled Trans Mountain Pipeline LP, Trans Mountain Pipeline Inc. and Kinder Morgan Canada Inc. v. The City of Burnaby, et al., Supreme Court of British Columbia, Vancouver Registry No. S078716. The suit alleges that the City of Burnaby and its agents are liable in damages including, but not limited to, all costs and expenses incurred by us as a result of the rupture of the pipeline and subsequent release of crude oil.

Although no assurance can be given, we believe that we have meritorious defenses to all pending pipeline integrity actions set forth in this note and, to the extent an assessment of the matter is possible, if it is probable that a liability has been incurred and the amount of loss can be reasonably estimated, we believe that we have established an adequate reserve to cover potential liability.

Additionally, although it is not possible to predict the ultimate outcomes, we also believe, based on our experiences to date, that the ultimate resolution of these matters will not have a material adverse impact on our business, financial position, results of operations or cash flows. As of December 31, 2007, and December 31, 2006, we have recorded a total reserve for legal fees, transportation rate cases and other litigation liabilities in the amount of $247.9 million and $112.0 million, respectively. The reserve is primarily related to various claims from lawsuits arising from our Pacific operations' pipeline transportation rates, and the contingent amount is based on both the circumstances of probability and reasonability of dollar estimates. We regularly assess the likelihood of adverse outcomes resulting from these claims in order to determine the adequacy of our liability provision.

Environmental Matters

Exxon Mobil Corporation v. GATX Corporation, Kinder Morgan Liquids Terminals, Inc. and ST Services, Inc.

On April 23, 2003, Exxon Mobil Corporation filed a complaint in the Superior Court of New Jersey, Gloucester County. We filed our answer to the complaint on June 27, 2003, in which we denied ExxonMobil's claims and allegations as well as included counterclaims against ExxonMobil. The lawsuit relates to environmental remediation obligations at a Paulsboro, New Jersey liquids terminal owned by ExxonMobil from the mid-1950s through November 1989, by GATX Terminals Corp. from 1989 through September 2000, later owned by ST Services, Inc. Prior to selling the terminal to GATX Terminals, ExxonMobil performed the environmental site assessment of the terminal required prior to sale pursuant to state law. During the site assessment, ExxonMobil discovered items that required remediation and the New Jersey Department of Environmental Protection issued an order that required ExxonMobil to perform various remediation activities to remove hydrocarbon contamination at the terminal. ExxonMobil, we understand, is still remediating the site and has not been removed as a responsible party from the state's cleanup order; however, ExxonMobil claims that the remediation continues because of GATX Terminals' storage of a fuel additive, MTBE, at the terminal during GATX Terminals' ownership of the terminal. When GATX Terminals sold the terminal to ST Services, the parties indemnified one another for certain environmental matters. When GATX Terminals was sold to us, GATX Terminals' indemnification obligations, if any, to ST Services may have passed to us. Consequently, at issue is any indemnification obligation we may owe to ST Services for environmental remediation of MTBE at the terminal. The complaint seeks any and all damages related to remediating MTBE at the terminal, and, according to the New Jersey Spill Compensation and Control Act, treble damages may be available for actual dollars incorrectly spent by the successful party in the lawsuit for remediating MTBE at the terminal. The parties are currently involved in mandatory mediation with respect to the claims set out in the lawsuit.

On June 25, 2007, the New Jersey Department of Environmental Protection, the Commissioner of the New Jersey Department of Environmental Protection and the Administrator of the New Jersey Spill Compensation Fund, referred to collectively as the plaintiffs, filed a complaint against Exxon Mobil Corporation and GATX Terminals Corporation. The complaint was filed in Gloucester County, New Jersey. The plaintiffs have not yet served the complaint on either of the named defendants. The plaintiffs seek the costs and damages that the plaintiffs allegedly have incurred or will incur as a result of the discharge of pollutants and hazardous substances at the Paulsboro, New Jersey facility. The costs and damages that the plaintiffs seek include damages to natural resources. In addition, the plaintiffs seek an order compelling the defendants to perform or fund the assessment and restoration of those natural resource damages that are the result of the defendants' actions. As in the case brought by Exxon Mobil against GATX Terminals Corporation, the issue is whether the plaintiffs' claims are within the scope of the indemnity obligations GATX Terminals and therefore, Kinder Morgan Liquids Terminals, owes to ST Services.

The City of Los Angeles v. Kinder Morgan Energy Partners, L.P.; Kinder Morgan Liquids Terminals LLC; Kinder Morgan Tank Storage Terminals LLC; Continental Oil Company; Chevron Corporation, California Superior Court, County of Los Angeles, Case No. NC041463.

We and some of our subsidiaries are defendants in a lawsuit filed in 2005 alleging claims for environmental cleanup costs and rent at the former Los Angeles Marine Terminal in the Port of Los Angeles. Plaintiff alleges that terminal cleanup costs could approach $18 million; however, Kinder Morgan believes that the clean up costs should be substantially less and that cleanup costs must be apportioned among all the parties to the litigation. Plaintiff also alleges that it is owed approximately $2.8 million in past rent and an unspecified amount for future rent. The judge bifurcated that rent issue from the causes of action related to the cleanup costs and a trial regarding the rent issue was set for October 2007.

Plaintiff and the Kinder Morgan defendants have since agreed to a settlement in principle under which we agreed to pay $3.2 million in satisfaction of all past and future rent obligations. In the fourth quarter of 2007, we finalized the settlement terms, filed with the court for final approval, and paid the $3.2 million in satisfaction of all past and future rent obligations.

Mission Valley Terminal Lawsuit

In August 2007, the City of San Diego, on its own behalf and purporting to act on behalf of the People of the state of California, filed a lawsuit against us and several affiliates seeking injunctive relief and unspecified damages allegedly resulting from hydrocarbon and MTBE impacted soils and groundwater beneath the city's stadium property in San Diego arising from historic operations at the Mission Valley terminal facility. The case was filed in the Superior Court of California, San Diego County, case number 37-2007-00073033-CU-OR-CTL. On September 26, 2007, we removed the case to the United States District Court, Southern District of California, case number 07CV1883WCAB. On October 3, 2007, we filed a Motion to Dismiss all counts of the Complaint, which motion is currently pending. To the extent any claims survive the Motion to Dismiss, we intend to vigorously defend against the claims asserted in the complaint. This site has been, and currently is, under the regulatory oversight and order of the California Regional Water Quality Control Board. We do not expect the cost of any settlement and remediation to be material.

Portland Harbor DOJ/EPA Investigation

The United States Department of Justice and the United States Environmental Protection Agency are continuing to investigate potential criminal charges relating to an alleged instance of improper disposal at sea of potash which allegedly occurred at the request of or with the knowledge of employees or third parties at a bulk terminal facility in Portland, Oregon which we operate. We are fully cooperating with the investigation and are engaged in ongoing discussions with the office of the United States Attorney for the District of Oregon and the Department of Justice in an attempt to resolve this matter.

Louisiana Department of Environmental Quality Settlement

After conducting a voluntary compliance self-audit, in April 2006, we voluntarily disclosed certain findings from the audit related to compliance with environmental regulations and permits at our Harvey and St. Gabriel Terminals to the Louisiana Department of Environmental Quality, referred to in this report as the LDEQ. Following further discussion between the LDEQ and us, in August 2007, the LDEQ issued a Consolidated Compliance Order and Notice of Potential Penalty for each of the two facilities. We and the LDEQ have reached agreement on a proposed settlement agreement under which we agree to finalize certain work, which we have already undertaken to ensure compliance with the environmental regulations at these two facilities, and to pay a penalty of $0.3 million. The proposed settlement agreement is undergoing public comment pursuant to LDEQ regulations, and then will be finalized.

Other Environmental

We are subject to environmental cleanup and enforcement actions from time to time. In particular, the federal Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) generally imposes joint and several liability for cleanup and enforcement costs on current or predecessor owners and operators of a site, among others, without regard to fault or the legality of the original conduct. Our operations are also subject to federal, state and local laws and regulations relating to protection of the environment. Although we believe our operations are in substantial compliance with applicable environmental law and regulations, risks of additional costs and liabilities are inherent in pipeline, terminal and carbon dioxide field and oil field operations, and there can be no assurance that we will not incur significant costs and liabilities. Moreover, it is possible that other developments, such as increasingly stringent environmental laws, regulations and enforcement policies thereunder, and claims for damages to property or persons resulting from our operations, could result in substantial costs and liabilities to us.

We are currently involved in several governmental proceedings involving air, water and waste violations issued by various governmental authorities related to compliance with environmental regulations. As we receive notices of non-compliance, we negotiate and settle these matters. We do not believe that these violations will have a material adverse affect on our business.

We are also currently involved in several governmental proceedings involving groundwater and soil remediation efforts under administrative orders or related state remediation programs issued by various regulatory authorities related to compliance with environmental regulations associated with our assets. We have established a reserve to address the costs associated with the cleanup.

In addition, we are involved with and have been identified as a potentially responsible party in several federal and state superfund sites. Environmental reserves have been established for those sites where our contribution is probable and reasonably estimable. In addition, we are from time to time involved in civil proceedings relating to damages alleged to have occurred as a result of accidental leaks or spills of refined petroleum products, natural gas liquids, natural gas and carbon dioxide. See "—Pipeline Integrity and Releases" above for additional information with respect to ruptures and leaks from our pipelines.

Although it is not possible to predict the ultimate outcomes, we believe that the resolution of the environmental matters set forth in this note will not have a material adverse effect on our business, financial position, results of operations or cash flows. However, we are not able to reasonably estimate when the eventual settlements of these claims will occur and changing circumstances could cause these matters to have a material adverse impact. As of December 31, 2007, we have accrued an environmental reserve of$92.0 million, and we believe the establishment of this environmental reserve is adequate such that the resolution of pending environmental matters will not have a material adverse impact on our business, cash flows, financial position or results of operations. As of December 31, 2006, our environmental reserve totaled $64.2 million. Additionally, many factors may change in the future affecting our reserve estimates, such as (i) regulatory changes; (ii) groundwater and land use near our sites; and (iii) changes in cleanup technology.

Other

We are a defendant in various lawsuits arising from the day-to-day operations of our businesses. Although no assurance can be given, we believe, based on our experiences to date, that the ultimate resolution of such items will not have a material adverse impact on our business, financial position, results of operations or cash flows.

17. Regulatory Matters

The tariffs we charge for transportation on our interstate common carrier pipelines are subject to rate regulation by the FERC, under the Interstate Commerce Act. The Interstate Commerce Act requires, among other things, that interstate petroleum products pipeline rates be just and reasonable and nondiscriminatory. Pursuant to FERC Order No. 561, effective January 1, 1995, interstate petroleum products pipelines are able to change their rates within prescribed ceiling levels that are tied to an inflation index. FERC Order No. 561-A, affirming and clarifying Order No. 561, expanded the circumstances under which interstate petroleum products pipelines may employ cost-of-service ratemaking in lieu of the indexing methodology, effective January 1, 1995. For each of the years ended December 31, 2007, 2006 and 2005, the application of the indexing methodology did not significantly affect tariff rates on our interstate petroleum products pipelines.

FERC Order No. 2004/690

Since November 2003, the FERC issued Orders No. 2004, 2004-A, 2004-B, 2004-C, and 2004-D, adopting new Standards of Conduct as applied to natural gas pipelines. The primary change from existing regulation was to make such standards applicable to an interstate natural gas pipeline’s interaction with many more affiliates (referred to as "energy affiliates"), including intrastate/Hinshaw natural gas pipelines (in general, a Hinshaw pipeline is a pipeline that receives gas at or within a state boundary, is regulated by an agency of that state, and all the gas it transports is consumed within that state), processors and gatherers and any company involved in natural gas or electric markets (including natural gas marketers) even if they do not ship on the affiliated interstate natural gas pipeline. Local distribution companies were excluded, however, if they do not make sales to customers not physically attached to their system. The Standards of Conduct require, among other things, separate staffing of interstate pipelines and their energy affiliates (but support functions and senior management at the central corporate level may be shared) and strict limitations on communications from an interstate pipeline to an energy affiliate.

Every interstate natural gas pipeline was required to file an Order No. 2004 compliance plan with the FERC, and on July 20, 2006, the FERC accepted our interstate pipelines’ May 19, 2005 compliance filing under Order No. 2004. On November 17, 2006, the United States Court of Appeals for the District of Columbia Circuit, in Docket No. 04-1183, vacated FERC Orders 2004, 2004-A, 2004-B, 2004-C, and 2004-D as applied to natural gas pipelines, and remanded these same orders back to the FERC.

On January 9, 2007, the FERC issued an Interim Rule, effective January 9, 2007, in response to the court’s action. In the Interim Rule, the FERC readopted the Standards of Conduct, but revised or clarified with respect to issues which had been appealed to the court. Specifically, the following changes were made:

- the Standards of Conduct apply only to the relationship between interstate gas transmission pipelines and their marketing affiliates, not their energy affiliates;
- all risk management personnel can be shared;
- the requirement to post discretionary tariff actions was eliminated (but interstate gas pipelines must still maintain a log of discretionary tariff waivers);
- lawyers providing legal advice may be shared employees; and
- new interstate gas transmission pipelines are not subject to the Standards of Conduct until they commence service.

The FERC clarified that all exemptions and waivers issued under Order No. 2004 remain in effect. On January 18, 2007, the FERC issued a notice of proposed rulemaking seeking comments regarding whether or not the Interim Rule should be made permanent for natural gas transmission providers. On March 21, 2007, FERC issued an Order on Clarification and Rehearing of the Interim Rule that granted clarification that the Standards of Conduct only apply to natural gas transmission providers that are affiliated with a marketing or brokering entity that conducts transportation transactions on such gas transmission provider’s pipeline.

Notice of Inquiry – Financial Reporting

On February 15, 2007, the FERC issued a notice of inquiry seeking comment on the need for changes or revisions to the FERC’s reporting requirements contained in the financial forms for gas and oil pipelines and electric utilities. Initial comments were filed by numerous parties on March 27, 2007, and reply comments were filed on April 27, 2007.

On September 20, 2007, the FERC issued for public comment in Docket No. RM07-9 a proposed rule which would revise its financial forms to require that additional information be reported by natural gas companies. The proposed rule would require, among other things, that natural gas companies: (i) submit additional revenue information, including revenue from shipper-supplied gas; (ii) identify the costs associated with affiliate transactions; and (iii) provide additional information on incremental facilities and on discounted and negotiated rates. The FERC proposes an effective date of January 1, 2008, which means that forms reflecting the new requirements for 2008 would be filed in early 2009. Comments on the proposed rule were filed by numerous parties on November 13, 2007.

Notice of Inquiry – Fuel Retention Practices

On September 20, 2007, the FERC issued a Notice of Inquiry seeking comment on whether it should change its current policy and prescribe a uniform method for all interstate gas pipelines to use in recovering fuel gas and gas lost and unaccounted for. The Notice of Inquiry included numerous questions regarding fuel recovery issues and the effects of fixed fuel percentages as compared with tracking provisions. Comments on the Notice of Inquiry were filed by numerous parties on November 30, 2007.

Notice of Proposed Rulemaking – Promotion of a More Efficient Capacity Release Market

On November 15, 2007, the FERC issued a notice of proposed rulemaking in Docket No. RM 08-1-000 regarding proposed modifications to its Part 284 regulations concerning the release of firm capacity by shippers on interstate natural gas pipelines. The FERC proposes to remove, on a permanent basis, the rate ceiling on capacity release transactions of one year or less. Additionally, the FERC proposes to exempt capacity releases made as part of an asset management arrangement from the prohibition on tying and from the bidding requirements of section 284.8. Initial comments were filed by numerous parties on January 25, 2008.

Notice of Proposed Rulemaking – Natural Gas Price Transparency

On April 19, 2007, the FERC issued a notice of proposed rulemaking in Docket Nos. RM07-10-000 and AD06-11-000 regarding price transparency provisions of Section 23 of the Natural Gas Act and the Energy Policy Act. In the notice, the FERC proposed to revise its regulations to (i) require that intrastate pipelines post daily the capacities of, and volumes flowing through, their major receipt and delivery points and mainline segments in order to make available the information to track daily flows of natural gas throughout the United States; and (ii) require that buyers and sellers of more than a de minimis volume of natural gas report annual numbers and volumes of relevant transactions to the FERC in order to make possible an estimate of the size of the physical U.S. natural gas market, assess the importance of the use of index pricing in that market, and determine the size of the fixed-price trading market that produces the information. The FERC believes these revisions to its regulations will facilitate price transparency in markets for the sale or transportation of physical natural gas in interstate commerce. Initial comments were filed on July 11, 2007 and reply comments were filed on August 23, 2007. In addition, the FERC conducted an informal workshop in this proceeding on July 24, 2007, to discuss implementation and other technical issues associated with the proposals set forth in the NOPR.

On December 26, 2007, the FERC issued Order No. 704 in this docket implementing only the annual reporting provisions of the NOPR with minimal changes to the original proposal. The order becomes effective February 4, 2008. The initial report is due May 1, 2009 for calendar year 2008. Subsequent reports are due by May 1 of each year for the previous calendar year. Order 704 will require most, if not all Kinder Morgan natural gas pipelines to report annual volumes of relevant transactions to the FERC.

In addition, on December 21, 2007, the FERC issued a new notice of proposed rulemaking in Docket No. RM08-2-000 regarding the daily posting provisions that were contained in Docket Nos. RM07-10-000 and AD06-11-000. The new NOPR proposes to exempt from the daily posting requirements those non-interstate pipelines that (i) flow less than 10 million MMBtus of natural gas per year, (ii) fall entirely upstream of a processing plant, and (iii) deliver more than ninety-five percent (95%) of the natural gas volumes they flow directly to end-users. However, the new NOPR expands the proposal to require that both interstate and non-exempt non-interstate pipelines post daily the capacities of, volumes scheduled at, and actual volumes flowing through, their major receipt and delivery points and mainline segments. Initial comments are due March 13, 2008 and reply comments are due April 14, 2008. A Technical Conference is scheduled for April 3, 2008.

Notice of Proposed Rulemaking - Rural Onshore Low Stress Hazardous Liquids Pipelines

On September 6, 2006, the PHMSA published a notice of proposed rulemaking (PHMSA 71 FR 52504) that proposed to extend certain threat-focused pipeline safety regulations to rural onshore low-stress hazardous liquid pipelines within a prescribed buffer of previously defined U.S. states. Low-stress hazardous liquid pipelines, except those in populated areas or that cross commercially navigable waterways, have not been subject to the safety regulations in PHMSA 49 CFR Part 195.1. According to the PHMSA, unusually sensitive areas are areas requiring extra protection because of the presence of sole-source drinking water resources, endangered species, or other ecological resources that could be adversely affected by accidents or leaks occurring on hazardous liquid pipelines.

The notice proposed to define a category of "regulated rural onshore low-stress lines" (rural lines operating at or below 20% of specified minimum yield strength, with a diameter of eight and five-eighths inches or greater, located in or within a quarter-mile of a U.S. state) and to require operators of these lines to comply with a threat-focused set of requirements in Part 195 that already apply to other hazardous liquid pipelines. The proposed safety requirements addressed the most common threats—corrosion and third party damage—to the integrity of these rural lines. The proposal intended to provide additional integrity protection, to avoid significant adverse environmental consequences, and to improve public confidence in the safety of unregulated low-stress lines.

Since the new notice is a proposed rulemaking in which the PHMSA will consider initial and reply comments from industry participants, it is not clear what impact the final rule will have on the business of our intrastate and interstate pipeline companies.

Natural Gas Pipeline Expansion Filings

Rockies Express Pipeline-Currently Certificated Facilities

We operate and own a 51% ownership interest in West2East Pipeline LLC, a limited liability company that is the sole owner of Rockies Express Pipeline LLC. ConocoPhillips owns a 24% ownership interest in West2East Pipeline LLC and Sempra Energy holds the remaining 25% interest. When construction of the entire Rockies Express Pipeline project is completed, our ownership interest will be reduced to 50% at which time the capital accounts of West2East Pipeline LLC will be trued up to reflect our 50% economics in the project. According to the provisions of current accounting standards, due to the fact that we will receive 50% of the economics of the Rockies Express project on an ongoing basis, we are not considered the primary beneficiary of West2East Pipeline LLC and thus, we account for our investment under the equity method of accounting.

On August 9, 2005, the FERC approved the application of Rockies Express Pipeline LLC, formerly known as Entrega Gas Pipeline LLC, to construct 327 miles of pipeline facilities in two phases. For phase I (consisting of two pipeline segments), Rockies Express was granted authorization to construct and operate approximately 136 miles of pipeline extending northward from the Meeker Hub, located at the northern end of our TransColorado pipeline system in Rio Blanco County, Colorado, to the Wamsutter Hub in Sweetwater County, Wyoming (segment 1), and then construct approximately 191 miles of pipeline eastward to the Cheyenne Hub in Weld County, Colorado (segment 2). Construction of segments 1 and 2 has been completed, with interim service commencing on segment 1 on February 24, 2006, and full in-service of both segments on February 14, 2007. For phase II, Rockies Express was authorized to construct three compressor stations referred to as the Meeker, Big Hole and Wamsutter compressor stations. The Meeker and Wamsutter stations went into service in January 2008. Construction of the Big Hole compressor station is planned to commence in the second quarter of 2008, in order to meet an expected in-service date of June 30, 2009.

Rockies Express Pipeline-West Project

On April 19, 2007, the FERC issued a final order approving the Rockies Express application for authorization to construct and operate certain facilities comprising its proposed "Rockies Express-West Project." This project is the first planned segment extension of the Rockies Express' currently certificated facilities, and it will be comprised of approximately 713 miles of 42-inch diameter pipeline extending from the Cheyenne Hub to an interconnection with Panhandle Eastern Pipe Line located in Audrain County, Missouri. The segment extension proposes to transport approximately 1.5 billion cubic feet per day of natural gas across the following five states: Wyoming, Colorado, Nebraska, Kansas and Missouri. The project will also include certain improvements to existing Rockies Express facilities located to the west of the Cheyenne Hub. Construction commenced on May 21, 2007, and the project entered interim service to upstream delivery points on January 12, 2008. This project is expected to be fully operational in March 2008.

Rockies Express Pipeline-East Project

On April 30, 2007, Rockies Express filed an application with the FERC requesting a certificate of public convenience and necessity that would authorize construction and operation of the Rockies Express-East Project. The Rockies Express-East Project will be comprised of approximately 639 miles of 42-inch diameter pipeline commencing from the terminus of the Rockies Express-West pipeline to a terminus near the town of Clarington in Monroe County, Ohio and will be capable of transporting approximately 1.8 billion cubic feet per day of natural gas. On September 7, 2007, the FERC issued a Notice of Schedule for Environmental Review for the Rockies Express-East Project, referred to as the posted schedule. Rockies Express has requested that the FERC issue an updated scheduling order to modify the posted schedule for earlier resolution. Without a modification of the posted schedule, Rockies Express has concerns about its ability to complete its project by June 2009. Rockies Express is working closely with the FERC staff and other cooperating agencies to meet a revised schedule that was developed in consultation with the FERC staff at a public meeting convened on September 21, 2007. On November 23, 2007, the FERC issued a draft environmental impact statement for the project, in advance of the posted schedule. Comments on the environmental impact statement were submitted January 14, 2008, also in advance of the posted schedule. While there can be no assurance that the FERC will approve the revised schedule, subject to that approval, the Rockies Express-East Project is expected to begin partial service on December 31, 2008, and to be in full service in June 2009.

TransColorado Pipeline

On April 19, 2007, the FERC issued an order approving TransColorado Gas Transmission Company LLC’s application for authorization to construct and operate certain facilities comprising its proposed "Blanco-Meeker Expansion Project." This project provides for the transportation of up to approximately 250 million cubic feet per day of natural gas from the Blanco Hub area in San Juan County, New Mexico through TransColorado’s existing interstate pipeline for delivery to the Rockies Express Pipeline at an existing point of interconnection located in the Meeker Hub in Rio Blanco County, Colorado. Construction commenced on May 9, 2007, and the project was completed and entered service January 1, 2008.

Kinder Morgan Interstate Gas Transmission Pipeline

On August 6, 2007, KMIGT filed, in FERC Docket CP07-430, for regulatory approval to construct and operate a 41-mile, $29 million natural gas pipeline from the Cheyenne Hub to markets in and around Greeley, Colorado. When completed, the Colorado Lateral will provide firm transportation of up to 55 million cubic feet per day to a local utility under long-term contract. The FERC issued a draft environmental assessment on the project on January 11, 2008, and comments on the project were received February 11, 2008. Public Service Company of Colorado, a competitor to serving markets off the Colorado Lateral, reported that it had filed a complaint before the State of Colorado Public Utilities Commission against Atmos, the anchor shipper on the project. The Colorado Public Utilities Commission has set a hearing for April 8, 2008 on the complaint. Public Service Company of Colorado has requested the FERC delay the issuance of approvals to KMIGT, pending the outcome of the complaint proceeding.

On December 21, 2007, KMIGT filed, in Docket CP 08-44, for approval to expand its system in Nebraska to serve incremental ethanol and industrial load. The application is pending before the FERC until March 10, 2008, at which time the project will be approved if no protests are filed.

Kinder Morgan Louisiana Pipeline

On September 8, 2006, in FERC Docket No. CP06-449-000, we filed an application with the FERC requesting approval to construct and operate our Kinder Morgan Louisiana Pipeline. The natural gas pipeline will extend approximately 135 miles from Cheniere's Sabine Pass liquefied natural gas terminal in Cameron Parish, Louisiana, to various delivery points in Louisiana and will provide interconnects with many other natural gas pipelines, including Natural Gas Pipeline Company of America. The project is supported by fully subscribed capacity and long-term customer commitments with Chevron and Total. The entire project cost is approximately $510 million project and it is expected to be in service by January 1, 2009.

On March 15, 2007, the FERC issued a preliminary determination that the authorizations requested, subject to some minor modifications, will be in the public interest. This order does not consider or evaluate any of the environmental issues in this proceeding. On April 19, 2007, the FERC issued the final Environmental Impact Statement, which addressed the potential environmental effects of the construction and operation of the Kinder Morgan Louisiana Pipeline. The final EIS was prepared to satisfy the requirements of the National Environmental Policy Act. It concluded that approval of the Kinder Morgan Louisiana Pipeline project would have limited adverse environmental impacts. On June 22, 2007, the FERC issued an order granting construction and operation of the project. Kinder Morgan Louisiana Pipeline officially accepted the order on July 10, 2007.

Midcontinent Express Pipeline

On October 9, 2007, in Docket No. CP08-6-000, Midcontinent Express Pipeline LLC filed an application with the FERC requesting a certificate of public convenience and necessity that would authorize construction and operation of the approximate 500-mile Midcontinent Express Pipeline natural gas transmission system. On February 8, 2008, the FERC issued a draft environmental impact statement which stated that the building and operation of the proposed 504-mile Midcontinent Express Pipeline would result in limited adverse environmental impact. A final environmental impact statement must be released before the FERC can issue a certificate authorizing construction. Subject to the receipt of regulatory approvals, construction of the pipeline is expected to commence in August 2008 and be in service during the first quarter of 2009.

The Midcontinent Express Pipeline will create long-haul, firm transportation takeaway capacity either directly or indirectly connected to natural gas producing regions located in Texas, Oklahoma and Arkansas. The pipeline will originate in southeastern Oklahoma and traverse east through Texas, Louisiana, Mississippi, and terminate close to the Alabama border, providing capability to transport natural gas supplies to major pipeline interconnects along the route up to its terminus at Transco's Station 85. The Midcontinent Express Pipeline will have an initial capacity of up to 1.4 billion cubic feet and a total capital cost of approximately $1.3 billion. The pipeline is a 50/50 joint venture between ourselves and Energy Transfer Partners, L.P.

18. Recent Accounting Pronouncements

SFAS No. 123R

On December 16, 2004, the Financial Accounting Standards Board issued SFAS No. 123R (revised 2004), "Share-Based Payment." This Statement amends SFAS No. 123, "Accounting for Stock-Based Compensation," and requires companies to expense the value of employee stock options and similar awards. Significant provisions of SFAS No. 123R include the following: (i) share-based payment awards result in a cost that will be measured at fair value on the awards' grant date, based on the estimated number of awards that are expected to vest (compensation cost for awards that vest would not be reversed if the awards expire without being exercised); (ii) when measuring fair value, companies can choose an option-pricing model that appropriately reflects their specific circumstances and the economics of their transactions; and (iii) companies will recognize compensation cost for share-based payment awards as they vest, including the related tax effects. Upon settlement of share-based payment awards, the tax effects will be recognized in the income statement or additional paid-in capital.

For us, this Statement became effective January 1, 2006. However, we have not granted common unit options or made any other share-based payment awards since May 2000, and as of December 31, 2005, all outstanding options to purchase our common units were fully vested. Therefore, the adoption of this Statement did not have an effect on our consolidated financial statements due to the fact that we have reached the end of the requisite service period for any compensation cost resulting from share-based payments made under our common unit option plan.

SFAS No. 154

On June 1, 2005, the FASB issued SFAS No. 154, "Accounting Changes and Error Corrections." This Statement replaces Accounting Principles Board Opinion No. 20, "Accounting Changes" and SFAS No. 3, "Reporting Accounting Changes in Interim Financial Statements." SFAS No. 154 applies to all voluntary changes in accounting principle, and changes the requirements for accounting for and reporting of a change in accounting principle. SFAS No. 154 requires retrospective application to prior periods' financial statements of a voluntary change in accounting principle unless it is impracticable. In contrast, APB No. 20 previously required that most voluntary changes in accounting principle be recognized by including in net income of the period of the change the cumulative effect of changing to the new accounting principle.

The provisions of this Statement are effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005 (January 1, 2006 for us). The Statement does not change the transition provisions of any existing accounting pronouncements, including those that are in a transition phase as of the effective date of this Statement. Adoption of this Statement did not have any immediate effect on our consolidated financial statements, and we will apply this guidance prospectively.

EITF 04-5

In June 2005, the Emerging Issues Task Force reached a consensus on Issue No. 04-5, or EITF 04-5, "Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights." EITF 04-5 provides guidance for purposes of assessing whether certain limited partners rights might preclude a general partner from controlling a limited partnership.

For general partners of all new limited partnerships formed, and for existing limited partnerships for which the partnership agreements are modified, the guidance in EITF 04-5 is effective after June 29, 2005. For general partners in all other limited partnerships, the guidance is effective no later than the beginning of the first reporting period in fiscal years beginning after December 15, 2005 (January 1, 2006, for us). The adoption of EITF 04-5 did not have an effect on our consolidated financial statements.

Nonetheless, as a result of EITF 04-5, as of January 1, 2006, our financial statements are consolidated into the consolidated financial statements of Knight. Notwithstanding the consolidation of our financial statements into the consolidated financial statements of Knight pursuant to EITF 04-5, Knight is not liable for, and its assets are not available to satisfy, the obligations of us and/or our subsidiaries and vice versa. Responsibility for payments of obligations reflected in our or Knight's financial statements is a legal determination based on the entity that incurs the liability. The determination of responsibility for payment among entities in our consolidated group of subsidiaries was not impacted by the adoption of EITF 04-5.

SFAS No. 155

On February 16, 2006, the FASB issued SFAS No. 155, "Accounting for Certain Hybrid Financial Instruments." This Statement amends SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" and SFAS No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities." This Statement allows financial instruments that have embedded derivatives to be accounted for as a whole (eliminating the need to bifurcate the derivative from its host) if the holder elects to account for the whole instrument on a fair value basis. For us, this Statement became effective January 1, 2007. Adoption of this Statement has had no effect on our consolidated financial statements.

SFAS No. 156

On March 17, 2006, the FASB issued SFAS No. 156, "Accounting for Servicing of Financial Assets." This Statement amends SFAS No. 140 and addresses the recognition and measurement of separately recognized servicing assets and liabilities, such as those common with mortgage securitization activities, and provides an approach to simplify efforts to obtain hedge-like (offset) accounting by permitting a servicer that uses derivative financial instruments to offset risks on servicing to report both the derivative financial instrument and related servicing asset or liability by using a consistent measurement attribute—fair value. For us, this Statement became effective January 1, 2007. Adoption of this Statement has had no effect on our consolidated financial statements.

EITF 06-3

On June 28, 2006, the FASB ratified the consensuses reached by the Emerging Issues Task Force on EITF 06-3, "How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement (That is, Gross versus Net Presentation)." According to the provisions of EITF 06-3: (i) taxes assessed by a governmental authority that are directly imposed on a revenue-producing transaction between a seller and a customer may include, but are not limited to, sales, use, value added, and some excise taxes; and (ii) the presentation of such taxes on either a gross (included in revenues and costs) or a net (excluded from revenues) basis is an accounting policy decision that should be disclosed pursuant to Accounting Principles Board Opinion No. 22 (as amended) "Disclosure of Accounting Policies."

In addition, for any such taxes that are reported on a gross basis, a company should disclose the amounts of those taxes in interim and annual financial statements for each period for which an income statement is presented if those amounts are significant. The disclosure of those taxes can be done on an aggregate basis. EITF 06-3 applies to financial reports for interim and annual reporting periods beginning after December 15, 2006 (January 1, 2007 for us). The adoption of EITF 06-3 had no effect on our consolidated financial statements.

FIN 48

In July 2006, the FASB issued Interpretation (FIN) No. 48, "Accounting for Uncertainty in Income Taxes—an Interpretation of FASB Statement No. 109," which became effective January 1, 2007. FIN 48 addressed the determination of how tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. Under FIN 48, we must recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based not only on the technical merits of the tax position based on tax law, but also the past administrative practices and precedents of the taxing authority. The tax benefits recognized in the financial statements from such a position are measured based on the largest benefit that has a greater than 50% likelihood of being realized upon ultimate resolution.

Our adoption of FIN No. 48 on January 1, 2007 did not result in a cumulative effect adjustment to "Partners' Capital" on our consolidated balance sheet. A reconciliation of our beginning and ending gross unrecognized tax benefits for 2007 is as follows (in millions):

	2007
Balance at beginning of period	$ 3.2
Additions based on current year tax positions	4.7
Additions based on prior year tax positions	0.1
Reductions based on settlements with taxing authority	—
Reductions due to lapse in statute of limitations	(1.7)
Balance at end of period	$ 6.3

Our continuing practice is to recognize interest and/or penalties related to income tax matters in income tax expense, and as of January 1, 2007, we had $1.1 million of accrued interest and no accrued penalties. As of December 31, 2007 (i) we had $0.6 million of accrued interest and no accrued penalties; (ii) we believe it is reasonably possible that our liability for unrecognized tax benefits will decrease by approximately $1.2 million during the next twelve months; and (iii) we believe approximately $5.4 million of the total $6.3 million of unrecognized tax benefits on our consolidated balance sheet as of December 31, 2007 would affect our effective income tax rate in future periods in the event those unrecognized tax benefits were recognized. In addition, we have U.S. and state tax years open to examination for the periods 2003 through 2007.

SAB 108

In September 2006, the Securities and Exchange Commission issued Staff Accounting Bulletin No. 108. This Bulletin requires a "dual approach" for quantifications of errors using both a method that focuses on the income statement impact, including the cumulative effect of prior years' misstatements, and a method that focuses on the period-end balance sheet. For us, SAB No. 108 was effective January 1, 2007. The adoption of this Bulletin did not have a material impact on our consolidated financial statements, and we will apply this guidance prospectively.

SFAS No. 157

On September 15, 2006, the FASB issued SFAS No. 157, "Fair Value Measurements." This Statement establishes a single definition of fair value and a framework for measuring fair value in generally accepted accounting principles that should result in increased consistency and comparability in fair value measurements. SFAS No. 157 also expands disclosures about fair value measurements, improving the quality of information provided to users of financial statements. The provisions of this Statement apply to other accounting pronouncements that require or permit fair value measurements; the Board having previously concluded in those accounting pronouncements that fair value is the relevant measurement attribute. Accordingly, this Statement does not require any new fair value measurements.

On February 12, 2008, the FASB issued Financial Staff Position FAS 157-2, "Effective Date of FASB Statement No. 157." This Staff Position delays the effective date of SFAS No. 157 for all nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). The delay is intended to allow the Board and constituents additional time to consider the effect of various implementation issues that have arisen, or that may arise, from the application of SFAS No. 157.

The remainder of SFAS No. 157 was adopted by us effective January 1, 2008. The adoption of this Statement did not have an impact on our balance sheet, statement of income, or statement of cash flows since we already apply its basic concepts in measuring fair values.

SFAS No. 158

On September 29, 2006, the FASB issued SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statement Nos. 87, 88, 106 and 132(R)." This Statement requires an employer to: (i) recognize the overfunded or underfunded status of a defined benefit pension plan or postretirement benefit plan (other than a multiemployer plan) as an asset or liability in its statement of financial position; (ii) measure a plan's assets and its obligations that determine its funded status as of the end of the employer's fiscal year (with limited exceptions), and to disclose in the notes to financial statements additional information about certain effects on net periodic benefit cost for the next fiscal year that arise from delayed recognition of the gains or losses, prior service costs or credits, and transition assets or obligations; and (iii) recognize changes in the funded status of a plan in the year in which the changes occur through comprehensive income.

Past accounting standards only required an employer to disclose the complete funded status of its plans in the notes to the financial statements. Recognizing the funded status of a company's benefit plans as a net liability or asset on its balance sheet will require an offsetting adjustment to "Accumulated other comprehensive income/loss" in shareholders' equity ("Partners' Capital" for us). SFAS No. 158 does not change how pensions and other postretirement benefits are accounted for and reported in the income statement—companies will continue to follow the existing guidance in previous accounting standards. Accordingly, the amounts to be recognized in "Accumulated other comprehensive income/loss" representing unrecognized gains/losses, prior service costs/credits, and transition assets/obligations will continue to be amortized under the existing guidance. Those amortized amounts will continue to be reported as net periodic benefit cost in the income statement. Prior to SFAS No. 158, those unrecognized amounts were only disclosed in the notes to the financial statements.

According to the provisions of this Statement, an employer with publicly traded equity securities is required to initially recognize the funded status of a defined benefit pension plan or postretirement benefit plan and to provide the required disclosures as of the end of the fiscal year ending after December 15, 2006 (December 31, 2006 for us). For us, the adoption of this part of SFAS No. 158 did not have a material effect on our statement of financial position as of December 31, 2006.

In addition, the requirement to measure plan assets and benefit obligations as of the date of the employer's fiscal year-end statement of financial position is effective for fiscal years ending after December 15, 2008 (December 31, 2008 for us). In the year that the measurement date provisions of this Statement are initially applied, a business entity is required to disclose the separate adjustments of retained earnings ("Partners' Capital" for us) and "Accumulated other comprehensive income/loss" from applying this Statement. While earlier application of the recognition of measurement date provisions is allowed, we have opted not to adopt this part of the Statement early. For more information on our pensions and other post-retirement benefit plans, and our disclosures regarding the provisions of this Statement, please see Note 10.

SFAS No. 159

On February 15, 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities." This Statement provides companies with an option to report selected financial assets and liabilities at fair value. The Statement's objective is to reduce both complexity in accounting for financial instruments and the volatility in earnings caused by measuring related assets and liabilities differently. The Statement also establishes presentation and disclosure requirements designed to facilitate comparisons between companies that choose different measurement attributes for similar types of assets and liabilities.

SFAS No. 159 requires companies to provide additional information that will help investors and other users of financial statements to more easily understand the effect of the company's choice to use fair value on its earnings. It also requires entities to display the fair value of those assets and liabilities for which the company has chosen to use fair value on the face of the balance sheet. The Statement does not eliminate disclosure requirements included in other accounting standards, including requirements for disclosures about fair value measurements included in SFAS No. 157, discussed above, and SFAS No. 107 "Disclosures about Fair Value of Financial Instruments."

This Statement was adopted by us effective January 1, 2008, at which time no financial assets or liabilities, not previously required to be recorded at fair value by other authoritative literature, were designated to be recorded at fair value. As such, the adoption of this Statement did not have any impact on our financial statements.

SFAS 141(R)

On December 4, 2007, the FASB issued SFAS No. 141R (revised 2007), "Business Combinations." Although this statement amends and replaces SFAS No. 141, it retains the fundamental requirements in SFAS No. 141 that (i) the purchase method of accounting be used for all business combinations; and (ii) an acquirer be identified for each business combination. SFAS No. 141R defines the acquirer as the entity that obtains control of one or more businesses in the business combination and establishes the acquisition date as the date that the acquirer achieves control. This Statement applies to all transactions or other events in which an entity (the acquirer) obtains control of one or more businesses (the acquiree), including combinations achieved without the transfer of consideration; however, this Statement does not apply to a combination between entities or businesses under common control.

Significant provisions of SFAS No. 141R concern principles and requirements for how an acquirer (i) recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree; (ii) recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase; and (iii) determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination.

This Statement applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008 (January 1, 2009 for us). Early adoption is not permitted. We are currently reviewing the effects of this Statement.

SFAS No. 160

On December 4, 2007, the FASB issued SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements – an amendment of ARB No. 51." This Statement changes the accounting and reporting for noncontrolling interests in consolidated financial statements. A noncontrolling interest, sometimes referred to as a minority interest, is the portion of equity in a subsidiary not attributable, directly or indirectly, to a parent.

Specifically, SFAS No. 160 establishes accounting and reporting standards that require (i) the ownership interests in subsidiaries held by parties other than the parent be clearly identified, labeled, and presented in the consolidated balance sheet within equity, but separate from the parent's equity; (ii) the equity amount of consolidated net income attributable to the parent and to the noncontrolling interest be clearly identified and presented on the face of the consolidated income statement (consolidated net income and comprehensive income will be determined without deducting minority interest, however, earnings-per-share information will continue to be calculated on the basis of the net income attributable to the parent's shareholders); and (iii) changes in a parent's ownership interest while the parent retains its controlling financial interest in its subsidiary be accounted for consistently and similarly—as equity transactions.

This Statement is effective for fiscal years, and interim period within those fiscal years, beginning on or after December 15, 2008 (January 1, 2009 for us). Early adoption is not permitted. SFAS No. 160 shall be applied prospectively as of the beginning of the fiscal year in which it is initially applied, except for its presentation and disclosure requirements, which shall be applied retrospectively for all periods presented. We are currently reviewing the effects of this Statement.

19. Quarterly Financial Data (Unaudited)

	Operating Revenues	Operating Income	Income from Continuing Operations	Income from Discontinued Operations	Net Income
			(In millions)		
2007					
First Quarter(a)	$ 2,171.7	$ (75.5)	$ (156.6)	$ 7.1	$ (149.5)
Second Quarter	2,366.4	314.6	227.3	5.4	232.7
Third Quarter	2,230.8	311.4	205.2	8.6	213.8
Fourth Quarter	2,448.8	257.2	140.5	152.8	293.3
2006					
First Quarter	$ 2,413.3	$ 314.0	$ 249.9	$ 3.0	$ 252.9
Second Quarter	2,216.1	317.7	251.0	3.4	254.4
Third Quarter	2,296.8	311.4	227.1	2.4	229.5
Fourth Quarter	2,122.5	348.5	261.8	5.5	267.3

	Income (loss) from Continuing Operations	Income (loss) from Discontinued Operations	Net Income
Basic Limited Partners' income (loss) per Unit:			
2007			
First Quarter(a)	$ (1.27)	$ 0.03	$ (1.24)
Second Quarter	0.34	0.02	0.36
Third Quarter	0.21	0.03	0.24
Fourth Quarter	(0.12)	0.62	0.50
2006			
First Quarter	$ 0.54	$ 0.02	$ 0.56
Second Quarter	0.55	0.01	0.56
Third Quarter	0.41	0.01	0.42
Fourth Quarter	0.62	0.02	0.64
Diluted Limited Partners' income (loss) per Unit:			
2007			
First Quarter(a)	$ (1.27)	$ 0.04	$ (1.23)
Second Quarter	0.34	0.02	0.36
Third Quarter	0.21	0.03	0.24
Fourth Quarter	(0.12)	0.62	0.50
2006			
First Quarter	$ 0.54	$ 0.02	$ 0.56
Second Quarter	0.54	0.02	0.56
Third Quarter	0.41	0.01	0.42
Fourth Quarter	0.62	0.02	0.64

(a) 2007 first quarter includes an expense of $377.1 million attributable to a goodwill impairment charge recognized by Knight, as discussed in Notes 3 and 8.

20. Supplemental Information on Oil and Gas Producing Activities (Unaudited)

The Supplementary Information on Oil and Gas Producing Activities is presented as required by SFAS No. 69, "Disclosures about Oil and Gas Producing Activities." The supplemental information includes capitalized costs related to oil and gas producing activities; costs incurred for the acquisition of oil and gas producing activities, exploration and development activities; and the results of operations from oil and gas producing activities.

Supplemental information is also provided for per unit production costs; oil and gas production and average sales prices; the estimated quantities of proved oil and gas reserves; the standardized measure of discounted future net cash flows associated with proved oil and gas reserves; and a summary of the changes in the standardized measure of discounted future net cash flows associated with proved oil and gas reserves.

Our capitalized costs consisted of the following (in millions):

Capitalized Costs Related to Oil and Gas Producing Activities

	December 31,		
	2007	**2006**	**2005**
Consolidated Companies(a)			
Wells and equipment, facilities and other	$ 1,612.5	$ 1,369.5	$ 1,097.9
Leasehold	348.1	347.4	320.7
Total proved oil and gas properties	1,960.6	1,716.9	1,418.6
Accumulated depreciation and depletion	(725.5)	(470.2)	(303.3)
Net capitalized costs	$ 1,235.1	$ 1,246.7	$ 1,115.3

(a) Amounts relate to Kinder Morgan CO_2 Company, L.P. and its consolidated subsidaries. Includes capitalized asset retirement costs and associated accumulated depreciation. There are no capitalized costs associated with unproved oil and gas properties for the periods reported.

Our costs incurred for property acquisition, exploration and development were as follows (in millions):

Costs Incurred in Exploration, Property Acquisitions and Development

	Year Ended December 31,		
	2007	**2006**	**2005**
Consolidated Companies(a)			
Property Acquisition			
Proved oil and gas properties	$ —	$ 36.6	$ 6.4
Development	244.4	261.8	281.7

(a) Amounts relate to Kinder Morgan CO_2 Company, L.P. and its consolidated subsidaries. There are no capitalized costs associated with unproved oil and gas properties for the periods reported. All capital expenditures were made to develop our proved oil and gas properties and no exploration costs were incurred for the periods reported.

Our results of operations from oil and gas producing activities for each of the years 2007, 2006 and 2005 are shown in the following table (in millions):

Results of Operations for Oil and Gas Producing Activities

	Year Ended December 31,		
	2007	**2006**	**2005**
Consolidated Companies(a)			
Revenues(b)	$ 589.7	$ 524.7	$ 469.1
Expenses:			
Production costs	243.9	208.9	159.6
Other operating expenses(c)	56.9	66.4	59.0
Depreciation, depletion and amortization expenses	258.5	169.4	130.5
Total expenses	559.3	444.7	349.1
Results of operations for oil and gas producing activities	$ 30.4	$ 80.0	$ 120.0

(a) Amounts relate to Kinder Morgan CO_2 Company, L.P. and its consolidated subsidaries.

(b) Revenues include losses attributable to our hedging contracts of $434.2 million, $441.7 million and $374.3 million for the years ended December 31, 2007, 2006 and 2005, respectively.

(c) Consists primarily of carbon dioxide expense.

The table below represents estimates, as of December 31, 2007, of proved crude oil, natural gas liquids and natural gas reserves prepared by Netherland, Sewell and Associates, Inc. (independent oil and gas consultants) of Kinder Morgan CO_2 Company, L.P. and its consolidated subsidiaries' interests in oil and gas properties, all of which are located in the state of Texas. This data has been prepared using constant prices and costs, as discussed in subsequent paragraphs of this document. The estimates of reserves and future revenue in this document conforms to the guidelines of the United States Securities and Exchange Commission.

We believe the geologic and engineering data examined provides reasonable assurance that the proved reserves are recoverable in future years from known reservoirs under existing economic and operating conditions. Estimates of proved reserves are subject to change, either positively or negatively, as additional information becomes available and contractual and economic conditions change.

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, that is, prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations or declines based upon future conditions. Proved developed reserves are the quantities of crude oil, natural gas liquids and natural gas expected to be recovered through existing investments in wells and field infrastructure under current operating conditions. Proved undeveloped reserves require additional investments in wells and related infrastructure in order to recover the production.

During 2007, we filed estimates of our oil and gas reserves for the year 2006 with the Energy Information Administration of the U. S. Department of Energy on Form EIA-23. The data on Form EIA-23 was presented on a different basis, and included 100% of the oil and gas volumes from our operated properties only, regardless of our net interest. The difference between the oil reserves reported on Form EIA-23 and those reported in this report exceeds 5%.

Reserve Quantity Information

	Consolidated Companies(a)		
	Crude Oil (MBbls)	**NGLs (MBbls)**	**Nat. Gas (MMcf)(b)**
Proved developed and undeveloped reserves:			
As of December 31, 2004	123,731	20,245	1,590
Revisions of previous estimates(c)	9,807	(4,278)	1,608
Improved Recovery(d)	21,715	4,847	242
Production	(13,815)	(1,920)	(1,335)
Purchases of reserves in place	513	89	48
As of December 31, 2005	141,951	18,983	2,153
Revisions of previous estimates(e)	(4,615)	(6,858)	(1,408)
Production	(13,811)	(1,817)	(461)
Purchases of reserves in place	453	25	7
As of December 31, 2006	123,978	10,333	291
Revisions of previous estimates(f)	10,361	2,784	1,077
Production	(12,984)	(2,005)	(290)
As of December 31, 2007	121,355	11,112	1,078
Proved developed reserves:			
As of December 31, 2004	71,307	8,873	1,357
As of December 31, 2005	78,755	9,918	1,650
As of December 31, 2006	69,073	5,877	291
As of December 31, 2007	70,868	5,517	1,078

(a) Amounts relate to Kinder Morgan CO2 Company, L.P. and its consolidated subsidiaries.
(b) Natural gas reserves are computed at 14.65 pounds per square inch absolute and 60 degrees fahrenheit.
(c) Crude oil revisions are based on better than expected recoveries on the SACROC unit carbon dioxide flood project. Natural gas liquids revisions are based on a lower than expected natural gas liquid yield at the SACROC unit carbon dioxide flood project.
(d) Improved recovery is due to significant additional areas of the SACROC unit being added to the future carbon dioxide flood project.
(e) Based on lower than expected recoveries of a section of the SACROC unit carbon dioxide flood project.
(f) Associated with an expansion of the carbon dioxide flood project area of the SACROC unit.

The standardized measure of discounted cash flows and summary of the changes in the standardized measure computation from year-to-year are prepared in accordance with SFAS No. 69. The assumptions that underly the computation of the standardized measure of discounted cash flows may be summarized as follows:

- the standardized measure includes our estimate of proved crude oil, natural gas liquids and natural gas reserves and projected future production volumes based upon year-end economic conditions;
- pricing is applied based upon year-end market prices adjusted for fixed or determinable contracts that are in existence at year-end;
- future development and production costs are determined based upon actual cost at year-end;
- the standardized measure includes projections of future abandonment costs based upon actual costs at year-end; and
- a discount factor of 10% per year is applied annually to the future net cash flows.

Our standardized measure of discounted future net cash flows from proved reserves were as follows (in millions):

Standardized Measure of Discounted Future Net Cash Flows From Proved Oil and Gas Reserves

	As of December 31,		
	2007	**2006**	**2005**
Consolidated Companies(a)			
Future cash inflows from production	$ 12,099.5	$ 7,534.7	$ 9,150.6
Future production costs	(3,536.2)	(2,617.9)	(2,756.6)
Future development costs(b)	(1,919.2)	(1,256.8)	(869.0)
Undiscounted future net cash flows	6,644.1	3,660.0	5,525.0
10% annual discount	(2,565.7)	(1,452.2)	(2,450.0)
Standardized measure of discounted future net cash flows	$ 4,078.4	$ 2,207.8	$ 3,075.0

(a) Amounts relate to Kinder Morgan CO_2 Company, L.P. and its consolidated subsidaries.

(b) Includes abandonment costs.

The following table represents our estimate of changes in the standardized measure of discounted future net cash flows from proved reserves (in millions):

Changes in the Standardized Measure of Discounted Future Net Cash Flows From Proved Oil and Gas Reserves

	2007	**2006**	**2005**
Consolidated Companies(a)			
Present value as of January 1	$ 2,207.8	$ 3,075.0	$ 2,045.0
Changes during the year:			
Revenues less production and other costs(b)	(722.1)	(690.0)	(624.4)
Net changes in prices, production and other costs(b)	2,153.2	(123.0)	1,013.4
Development costs incurred	244.5	261.8	281.7
Net changes in future development costs	(547.8)	(446.0)	(492.3)
Purchases of reserves in place	—	3.2	9.4
Revisions of previous quantity estimates(c)	510.8	(179.5)	51.1
Improved Recovery(d)	—	—	587.5
Accretion of discount	198.1	307.4	204.4
Timing differences and other	33.9	(1.1)	(0.8)
Net change for the year	1,870.6	(867.2)	1,030.0
Present value as of December 31	$ 4,078.4	$ 2,207.8	$ 3,075.0

(a) Amounts relate to Kinder Morgan CO2 Company, L.P. and its consolidated subsidaries.
(b) Excludes the effect of losses attributable to our hedging contracts of $434.2 million, $441.7 million and $374.3 million for the years ended December 31, 2007, 2006 and 2005, respectively.
(c) 2007 revisions are associated with an expansion of the carbon dioxide flood project area for the SACROC unit. 2006 revisions are based on lower than expected recoveries from a section of the SACROC unit carbon dioxide flood project. 2005 revisions are based on better than expected crude oil recoveries on the SACROC unit carbon dioxide flood project, partially offset by a lower than expected natural gas liquids yield at the SACROC unit carbon dioxide flood project.
(d) Improved recovery is due to significant additional areas of the SACROC unit being added to the future carbon dioxide flood project.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

KINDER MORGAN ENERGY PARTNERS, L.P.
(A Delaware Limited Partnership)

By: **KINDER MORGAN G.P., INC.,**
its sole General Partner

By: **KINDER MORGAN MANAGEMENT, LLC,**
the Delegate of Kinder Morgan G.P., Inc.

By: /s/ KIMBERLY A. DANG

Kimberly A. Dang,
Vice President and Chief Financial Officer

Date: February 25, 2008

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons in the capacities and on the dates indicated.

Signature	Title	Date
/s/ KIMBERLY A. DANG Kimberly A. Dang	Vice President and Chief Financial Officer of Kinder Morgan Management, LLC, Delegate of Kinder Morgan G.P., Inc. (principal financial officer and principal accounting officer)	February 25, 2008
/s/ RICHARD D. KINDER Richard D. Kinder	Chairman of the Board and Chief Executive Officer of Kinder Morgan Management, LLC, Delegate of Kinder Morgan G.P., Inc. (principal executive officer)	February 25, 2008
/s/ EDWARD O. GAYLORD Edward O. Gaylord	Director of Kinder Morgan Management, LLC, Delegate of Kinder Morgan G.P., Inc.	February 25, 2008
/s/ GARY L. HULTQUIST Gary L. Hultquist	Director of Kinder Morgan Management, LLC, Delegate of Kinder Morgan G.P., Inc.	February 25, 2008
/s/ PERRY M. WAUGHTAL Perry M. Waughtal	Director of Kinder Morgan Management, LLC, Delegate of Kinder Morgan G.P., Inc.	February 25, 2008
/s/ C. PARK SHAPER C. Park Shaper	Director and President of Kinder Morgan Management, LLC, Delegate of Kinder Morgan G.P., Inc.	February 25, 2008

Section 2: EX-4 (EXHIBIT 4.28)

KINDER MORGAN MANAGEMENT, LLC

KINDER MORGAN G.P., INC.

OFFICERS' CERTIFICATE
PURSUANT TO SECTION 301 OF INDENTURE

Each of the undersigned, Kimberly A. Dang and David D. Kinder, the Vice President and Chief Financial Officer and the Vice President and Treasurer, respectively, of (i) Kinder Morgan Management, LLC (the "Company"), a Delaware limited liability company and the delegate of Kinder Morgan G.P., Inc. and (ii) Kinder Morgan G.P., Inc., a Delaware corporation and the general partner of Kinder Morgan Energy Partners, L.P., a Delaware limited partnership (the "Partnership"), on behalf of the Partnership, does hereby establish the terms of a series of senior debt Securities of the Partnership under the Indenture relating to senior debt Securities, dated as of January 31, 2003 (the "Indenture"), between the Partnership and U.S. Bank National Association, as successor trustee to Wachovia Bank, National Association (the "Trustee"), pursuant to resolutions adopted by the Board of Directors of the Company, or a committee thereof, on February 28, 2007, February 4, 2008 and February 5, 2008 and in accordance with Section 301 of the Indenture, as follows:

1. The title of the Securities shall be "5.95% Senior Notes due 2018" (the "Notes");

2. The aggregate principal amount of the Notes which initially may be authenticated and delivered under the Indenture shall be limited to a maximum of $600,000,000, except for Notes authenticated and delivered upon registration of transfer of, or in exchange for, or in lieu of, other Notes pursuant to the terms of the Indenture, and except that any additional principal amount of the Notes may be issued in the future without the consent of Holders of the Notes so long as such additional principal amount of Notes are authenticated as required by the Indenture;

3. The Notes shall be issued on February 12, 2008, and the principal of the Notes shall be payable on February 15, 2018; the Notes will not be entitled to the benefit of a sinking fund;

4. The Notes shall bear interest at the rate of 5.95% per annum, which interest shall accrue from February 12, 2008, or from the most recent Interest Payment Date to which interest has been paid or duly provided for, which dates shall be February 15 and August 15 of each year, and such interest shall be payable semi-annually in arrears on February 15 and August 15 of each year, commencing August 15, 2008, to holders of record at the close of business on the February 1 or August 1, respectively, next preceding each such Interest Payment Date;

5. The principal of, premium, if any, and interest on, the Notes shall be payable at the office or agency of the Partnership maintained for that purpose in the Borough of Manhattan, New York, New York; provided, however, that at the option of the Partnership, payment of interest may be made from such office in the Borough of Manhattan, New York, New York by check mailed to the address of the person entitled thereto as such address shall appear in the Security Register. If at any time there shall be no such office or agency in the Borough of Manhattan, New York, New York, where the Notes may be presented or surrendered for

payment, the Partnership shall forthwith designate and maintain such an office or agency in the Borough of Manhattan, New York, New York, in order that the Notes shall at all times be payable in the Borough of Manhattan, New York, New York. The Partnership hereby initially designates the Corporate Trust Office of the Trustee in the Borough of Manhattan, New York, New York, as one such office or agency;

6. U.S. Bank National Association, successor trustee to Wachovia Bank, National Association, is appointed as the Trustee for the Notes, and U.S. Bank National Association, and any other banking institution hereafter selected by the officers of the Company, on behalf of the Partnership, are appointed agents of the Partnership (a) where the Notes may be presented for registration of transfer or exchange, (b) where notices and demands to or upon the Partnership in respect of the Notes or the Indenture may be made or served and (c) where the Notes may be presented for payment of principal and interest;

7. The Notes will be redeemable, at the Partnership's option, at any time in whole, or from time to time in part, upon not less than 30 and not more than 60 days notice mailed to each Holder of the Notes to be redeemed at the Holder's address appearing in the Security Register, at a price equal to 100% of the principal amount of the Notes to be redeemed plus accrued interest to the Redemption Date, subject to the right of Holders of record on the relevant Record Date to receive interest due on an Interest Payment Date that is on or prior to the Redemption Date, plus a make-whole premium, if any. In no event will the Redemption Price ever be less than 100% of the principal amount of the Notes being redeemed plus accrued interest to the Redemption Date.

The amount of the make-whole premium on any Note, or portion of a Note, to be redeemed will be equal to the excess, if any, of:

(1) the sum of the present values, calculated as of the Redemption Date, of:

- each interest payment that, but for the redemption, would have been payable on the Note, or portion of a Note, being redeemed on each interest payment date occurring after the Redemption Date, excluding any accrued interest for the period prior to the Redemption Date; and

- the principal amount that, but for the redemption, would have been payable at the stated maturity of the Note, or portion of a Note, being redeemed;

over

(2) the principal amount of the Note, or portion of a Note, being redeemed.

The present value of interest and principal payments referred to in clause (1) above will be determined in accordance with generally accepted principles of financial analysis. The present values will be calculated by discounting the amount of each payment of interest or principal from the date that each such payment would have been payable, but for the redemption, to the Redemption Date at a discount rate equal to the Treasury Yield, as defined below, plus 0.40%.

The make-whole premium will be calculated by an independent investment banking institution of national standing appointed by the Partnership. If the Partnership fails to make that appointment at least 30 business days prior to the redemption date, or if the institution so appointed is unwilling or unable to make the calculation, the financial institution named in the Notes will make the calculation. If the financial institution named in the Notes is unwilling or unable to make the calculation, an independent investment banking institution of national standing appointed by the Trustee will make the calculation.

For purposes of determining the make-whole premium, Treasury Yield refers to an annual rate of interest equal to the weekly average yield to maturity of United States Treasury Notes that have a constant maturity that corresponds to the remaining term to maturity of the Notes to be redeemed, calculated to the nearer 1/12 of a year (the "Remaining Term"). The Treasury Yield will be determined as of the third business day immediately preceding the applicable redemption date.

The weekly average yields of United States Treasury Notes will be determined by reference to the most recent statistical release published by the Federal Reserve Bank of New York and designated "H.15(519) Selected Interest Rates" or any successor release (the "H.15 Statistical Release"). If the H.15 Statistical Release sets forth a weekly average yield for United States Treasury Notes having a constant maturity that is the same as the Remaining Term of the Notes to be redeemed, then the Treasury Yield will be equal to that weekly average yield. In all other cases, the Treasury Yield will be calculated by interpolation, on a straight-line basis, between the weekly average yields on the United States Treasury Notes that have a constant maturity closest to and greater than the Remaining Term of the Notes to be redeemed and the United States Treasury Notes that have a constant maturity closest to and less than the Remaining Term, in each case as set forth in the H.15 Statistical Release. Any weekly average yields so calculated by interpolation will be rounded to the nearer 0.01%, with any figure of 0.0050% or more being rounded upward. If weekly average yields for United States Treasury Notes are not available in the H.15 Statistical Release or otherwise, then the Treasury Yield will be calculated by interpolation of comparable rates selected by the independent investment banking institution.

If less than all of the Notes are to be redeemed, the Trustee will select the Notes to be redeemed by a method that the Trustee deems fair and appropriate. The Trustee may select for redemption Notes and portions of Notes in amounts of $1,000 or whole multiples of $1,000.

8. Payment of principal of, and interest on, the Notes shall be without deduction for taxes, assessments or governmental charges paid by Holders of the Notes;

9. The Notes are approved in the form attached hereto as Exhibit A, shall be issued upon original issuance in whole in the form of one or more book-entry Global Securities, and the Depositary shall be The Depository Trust Company; and

10. The Notes shall be entitled to the benefits of the Indenture, including the covenants and agreements of the Partnership set forth therein, except to the extent expressly otherwise provided herein or in the Notes.

Any initially capitalized terms not otherwise defined herein shall have the meanings ascribed to such terms in the Indenture.

IN WITNESS WHEREOF, each of the undersigned has hereunto signed his or her name this 5th day of February, 2008.

/s/ Kimberly A. Dang

Kimberly A. Dang
Vice President and Chief Financial Officer

/s/ David D. Kinder

David D. Kinder
Vice President and Treasurer

[Signature Page to Officers' Certificate Establishing Series]

EXHIBIT A

Form of Global Note attached.

Section 3: EX-11 (EXHIBIT 11)

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES
EXHIBIT 11 – STATEMENT RE: COMPUTATION OF PER SHARE EARNINGS
(Units in millions; Dollars in millions except per unit amounts)

	Year Ended December 31,		
	2007	2006	2005
Weighted average number of limited partners' units on which limited partners' net income per unit is based:			
Basic	236.9	224.6	212.2
Add: Incremental units under common unit option plan and under contracts to issue units depending on the market price of the units at a future date	—	0.3	0.2
Assuming dilution	236.9	224.9	212.4
Calculation of Limited Partners' interest in Net Income:			
Income from Continuing Operations	$ 416.4	$ 989.8	$ 812.4
Less: General Partner's interest in Income from Continuing Operations	(609.9)	(513.2)	(477.3)
Limited Partners' interest in Income from Continuing Operations	(193.5)	476.6	335.1
Add: Limited Partners' interest in Income from Discontinued Operations	172.2	14.2	(0.2)
Limited Partners' interest in Net Income	$ (21.3)	$ 490.8	$ 334.9
Basic Limited Partners' Net Income per unit:			
Income from Continuing Operations	$ (0.82)	$ 2.12	$ 1.58
Income from Discontinued Operations	$ 0.73	$ 0.07	$ —
Net Income	$ (0.09)	$ 2.19	$ 1.58
Diluted Limited Partners' Net Income per unit:			
Income from Continuing Operations	$ (0.82)	$ 2.12	$ 1.58
Income from Discontinued Operations	$ 0.73	$ 0.06	$ —
Net Income	$ (0.09)	$ 2.18	$ 1.58

Section 4: EX-12 (EXHIBIT 12)

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES
EXHIBIT 12 – STATEMENT RE: COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES
(Dollars In millions except ratio amounts)

	Year Ended December 31,				
	2007	2006	2005	2004	2003
Earnings:					

Pre-tax income from continuing operations before cumulative effect of a change in accounting principle and before adjustment for minority interest and equity earnings (including amortization of excess cost of equity investments) per statements of income	$ 430.5	$ 965.8	$ 760.1	$ 769.6	$ 616.1
Add:					
Fixed charges	444.8	383.7	293.8	215.5	188.5
Amortization of capitalized interest	2.0	1.3	0.8	0.6	0.4
Distributed income of equity investees	101.6	66.3	61.1	63.9	81.7
Less:					
Interest capitalized from continuing operations	(31.4)	(20.3)	(9.8)	(6.3)	(5.3)
Minority interest in pre-tax income of subsidiaries with no fixed charges	(0.5)	(0.5)	(0.4)	(0.1)	—
Income as adjusted	$ 947.0	$ 1,396.3	$ 1,105.6	$ 1,043.2	$ 881.4
Fixed charges:					
Interest and debt expense, net per statements of income (includes amortization of debt discount, premium, and debt issuance costs; excludes capitalized interest)	$ 428.5	$ 365.8	$ 278.2	$ 202.5	$ 188.1
Add:					
Portion of rents representative of the interest factor	16.3	17.9	15.6	13.0	0.4
Fixed charges	$ 444.8	$ 383.7	$ 293.8	$ 215.5	$ 188.5
Ratio of earnings to fixed charges	2.13	3.64	3.76	4.84	4.68

Section 5: EX-21 (EXHIBIT 21.1)

KINDER MORGAN ENERGY PARTNERS, L.P.

Kinder Morgan Canada Company – Nova Scotia
Kinder Morgan North Texas Pipeline, L.P. - DE
Kinder Morgan Texas Gas Services LLC - DE
Kinder Morgan Transmix Company, LLC - DE
Kinder Morgan Interstate Gas Transmission LLC - CO
Kinder Morgan Trailblazer, LLC - DE
CGT Trailblazer, LLC - DE
Kinder Morgan Texas Pipeline, L.P. - DE
Kinder Morgan Operating L.P. "A" - DE
Kinder Morgan Operating L.P. "B" - DE
Kinder Morgan CO2 Company, L.P. - DE
Trailblazer Pipeline Company - IL
Kinder Morgan Bulk Terminals, Inc. - LA
Western Plant Services, Inc. - CA
Dakota Bulk Terminal, Inc. - WI
Delta Terminal Services LLC - DE
RCI Holdings, Inc. - LA
HBM Environmental, Inc. - LA
Milwaukee Bulk Terminals LLC - WI
Queen City Terminals, Inc. - DE
Kinder Morgan Port Terminals USA LLC - DE
Elizabeth River Terminals LLC - DE
Nassau Terminals LLC - DE
Fernandina Marine Construction Management LLC - DE
Kinder Morgan Port Manatee Terminal LLC - DE
Kinder Morgan Port Sutton Terminal LLC - DE

Pinney Dock & Transport LLC - OH
Kinder Morgan Operating L.P. "C" - DE
Kinder Morgan Operating L.P. "D" - DE
SFPP, L.P. - DE
Kinder Morgan Liquids Terminals LLC - DE
Kinder Morgan Pipeline LLC - DE
Kinder Morgan Tank Storage Terminals LLC - DE
Kinder Morgan 2-Mile LLC - DE
Rahway River Land LLC - DE
Central Florida Pipeline LLC - DE
Southwest Florida Pipeline LLC - DE
Calnev Pipe Line LLC - DE
Kinder Morgan Las Vegas LLC - DE
Globalplex Partners, Joint Venture - LA

Colton Processing Facility - CA
Kinder Morgan Materials Services, LLC - PA
CIG Trailblazer Gas Company, L.L.C. - DE
KM Trailblazer, LLC - DE
Kinder Morgan Border Pipeline, L.P. - DE
Tejas Gas, LLC - DE
Gulf Energy Gas, LLC - DE
Gulf Energy Gathering & Processing, LLC - DE
Gulf Energy Marketing, LLC - DE
Hydrocarbon Development, LLC - DE
Kinder Morgan Tejas Pipeline, L.P. - DE
Stellman Transportation, LLC - DE
Kinder Morgan Tejas Pipeline GP LLC - DE
Tejas Energy Partner, LLC - DE
Tejas Gas Systems, LLC - DE
Tejas-Gulf, LLC - DE
Tejas Natural Gas, LLC - DE
Kinder Morgan Pipeline Services of Mexico S. de R.L. de C.V. - Mexico
Valley Gas Transmission, LLC - DE
TransColorado LLC - DE
Silver Canyon Pipeline LLC - DE
Kinder Morgan Liquids Terminals St. Gabriel LLC - LA
Kinder Morgan Gas Natural de Mexico S. de R.L. de C.V. - Mexico
KM Production Company GP LLC - DE
Kinder Morgan Production Company LP - DE
Emory B Crane, LLC- LA
Frank L. Crane, LLC - LA
Paddy Ryan Crane, LLC - LA
Agnes B Crane, LLC - LA
KMBT LLC - DE
KM Production Company LP LLC - DE
KM Crane LLC - MD
MJR Operating LLC - MD
Kinder Morgan West Texas Pipeline, L.P. - DE
Kinder Morgan Southeast Terminals LLC - DE
International Marine Terminals - LA
I.M.T. Land Corp. - LA
ICPT, L.L.C. - LA
KM Crude Oil Pipelines GP LLC - DE
KM Crude Oil Pipelines LP LLC - DE
Kinder Morgan Crude Oil Pipelines, L.P. - DE
Kinder Morgan Carbon Dioxide Transportation Company - DE
Pecos Carbon Dioxide Transportation Company - TX
River Consulting, LLC – LA
KM Liquids Partners GP LLC - DE
KM Liquids Terminals, L.P. - DE

KM Liquids Holdings LLC - DE
Kinder Morgan Wink Pipeline, L.P. - DE
Kinder Morgan River Terminals LLC formerly Global Materials Services LLC- TN
Arrow Terminals B.V. - Dutch
Arrow Terminals Canada B. V. - Netherlands
Arrow Terminals Canada Company - NSULC
Kinder Morgan Arrow Terminals, L.P. LP - DE
Global American Terminals LLC - DE
Kinder Morgan Amory LLC - MS
Kinder Morgan Arrow Terminals Holdings, Inc. - DE
KM Decatur, Inc. - AL
Mid-South Port Transportation LLC
River Terminals Properties, LP - TN
Tajon Holdings, Inc. - PA
River Terminals Properties GP LLC - DE
Guilford County Terminal Company, LLC -NC
Johnston County Terminal, LLC
TransColorado Gas Transmission Company - CO
KM Upstream LLC -DE
Kinder Morgan Petcoke LP LLC - DE
Kinder Morgan Petcoke GP LLC - DE
Kinder Morgan Petcoke, L.P. - DE
Stevedore Holdings, L.P. - DE
Kinder Morgan NatGas Operator LLC - DE
General Stevedores Holdings LLC - DE
General Stevedores GP, LLC - TX
SRT Vessels LLC - DE
Carbon Exchange LLC - DE
Kinder Morgan Louisiana Pipeline Holding LLC - DE
Kinder Morgan Louisiana Pipeline LLC - DE
Kinder Morgan Pecos LLC - DE
Kinder Morgan W2E Pipeline LLC - DE
West2East Pipeline LLC - DE
Rockies Express Pipeline LLC formerly Entrega Gas Pipeline LLC- DE
Kinder Morgan Texas Terminals, L.P. - DE
Kinder Morgan Cameron Prairie Pipeline LLC - DE
Kinder Morgan Canada Terminals ULC - Alberta
Midcontinent Express Pipeline LLC - DE
Lomita Rail Terminal LLC - DE
Transload Services, LLC - IL
Devco USA, L.L.C. - OK
Kinder Morgan Cochin ULC - Alberta
Kinder Morgan Cochin LLC - DE
Kinder Morgan Seven Oaks LLC - DE
Kinder Morgan Columbus LLC - DE
KM Liquids Terminals LLC - DE

Kinder Morgan Production Company LLC - DE
Kinder Morgan Crude Oil Pipelines LLC - DE
Kinder Morgan Tejas Pipeline LLC - DE
Kinder Morgan Texas Pipeline LLC - DE
Kinder Morgan Wink Pipeline LLC - DE
Kinder Morgan North Texas Pipeline LLC - DE
Kinder Morgan Border Pipeline LLC - DE
Kinder Morgan Marine Services LLC - DE
Kinder Morgan Mid Atlantic Marine Services LLC - DE
TransColorado Gas Transmission Company LLC - DE
Trailblazer Pipeline Company LLC - DE

Section 6: EX-23 (EXHIBIT 23.1)

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on (i) Form S-3 (Nos. 333-25995, 333-62155, 333-33726, 333-54616, 333-60912-01, 333-55866-01, 333-91316-01, 333-102961, 333-102962-01, 333-122424, 333-124471, 333-141491 and 333-142584) and (ii) Form S-8 (Nos. 333-56343 and 333-122168) of Kinder Morgan Energy Partners, L.P. of our report dated February 25, 2008 relating to the financial statements and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
PricewaterhouseCoopers LLP
Houston, Texas
February 25, 2008

Section 7: EX-23 (EXHIBIT 23.2)

CONSENT OF NETHERLAND, SEWELL & ASSOCIATES, INC.

As oil and gas consultants, we hereby consent to the use of our name and our report dated January 18, 2008, in this Form 10-K, incorporated by reference into Kinder Morgan Energy Partners, L.P.'s previously filed Registration Statement File Nos. 333-122424, 333-25995, 333-62155, 333-33726, 333-54616, 333-60912-01, 333-55866-01, 333-91316-01, 333-102961, 333-102962-01 333-124471, 333-141491 and 333-142584 on Form S-3, and 333-122168 and 333-56343 on Form S-8.

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ Danny D. Simmons
Danny D. Simmons, P.E.
President and Chief Operating Officer

Houston, Texas
February 13, 2008

Section 8: EX-31 (EXHIBIT 31.1)

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES
EXHIBIT 31.1 – CERTIFICATION PURSUANT TO RULE 13A-14(A) OR 15D-14(A) OF THE SECURITIES EXCHANGE ACT OF 1934, AS ADOPTED PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Richard D. Kinder, certify that:

1. I have reviewed this annual report on Form 10-K of Kinder Morgan Energy Partners, L.P.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c) evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d) disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and
5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent function):
   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and
   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial information.

Date: February 25, 2008

/s/ Richard D. Kinder
Richard D. Kinder
Chairman and Chief Executive Officer

Section 9: EX-31 (EXHIBIT 31.2)

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES
EXHIBIT 31.2 – CERTIFICATION PURSUANT TO RULE 13A-14(A) OR 15D-14(A) OF THE SECURITIES EXCHANGE ACT OF 1934, AS ADOPTED PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Kimberly A. Dang certify that:

1. I have reviewed this annual report on Form 10-K of Kinder Morgan Energy Partners, L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent function):

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial information.

Date: February 25, 2008

/s/ Kimberly A. Dang
Kimberly A. Dang
Vice President and Chief Financial Officer

Section 10: EX-32 (EXHIBIT 32.1)

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES
EXHIBIT 32.1 – CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350, AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report on Form 10-K of Kinder Morgan Energy Partners, L.P. (the "Company") for the yearly period ending December 31, 2007, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), the undersigned, in the capacity and on the date indicated below, hereby certifies pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: February 25, 2008

/s/ Richard D. Kinder

Richard D. Kinder,
Chairman and Chief Executive Officer of Kinder Morgan Management, LLC, the delegate of Kinder Morgan G.P., Inc., the General Partner of Kinder Morgan Energy Partners, L.P.

Section 11: EX-32 (EXHIBIT 32.2)

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES
EXHIBIT 32.2 – CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350, AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report on Form 10-K of Kinder Morgan Energy Partners, L.P. (the "Company") for the yearly period ending December 31, 2007, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), the undersigned, in the capacity and on the date indicated below, hereby certifies pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: February 25, 2008

/s/ Kimberly A. Dang

Kimberly A. Dang
Vice President and Chief Financial Officer of Kinder Morgan Management, LLC, the delegate of Kinder Morgan G.P., Inc., the General Partner of Kinder Morgan Energy Partners, L.P.

10-Q 1 l32720ae10vq.htm NATIONAL FUEL GAS COMPANY 10-Q

Docket No. RP09-_____-000
Exhibit No. HIO-74
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

þ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended June 30, 2008

OR

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from__________ to__________

Commission File Number 1-3880

NATIONAL FUEL GAS COMPANY
(Exact name of registrant as specified in its charter)

New Jersey	**13-1086010**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
6363 Main Street Williamsville, New York	**14221**
(Address of principal executive offices)	(Zip Code)

(716) 857-7000
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months and (2) has been subject to such filing requirements for the past 90 days. YES þ NO o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer, or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer þ	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). YES o NO þ

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date:

Common stock, $1 par value, outstanding at July 31, 2008: 81,475,950 shares.

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GLOSSARY OF TERMS

Frequently used abbreviations, acronyms, or terms used in this report:

National Fuel Gas Companies

Company	The Registrant, the Registrant and its subsidiaries or the Registrant's subsidiaries as appropriate in the context of the disclosure
Data-Track	Data-Track Account Services, Inc.
Distribution Corporation	National Fuel Gas Distribution Corporation
Empire	Empire State Pipeline
ESNE	Energy Systems North East, LLC
Highland	Highland Forest Resources, Inc.
Horizon	Horizon Energy Development, Inc.
Horizon LFG	Horizon LFG, Inc.
Horizon Power	Horizon Power, Inc.
Leidy Hub	Leidy Hub, Inc.
Model City	Model City Energy, LLC
National Fuel	National Fuel Gas Company
NFR	National Fuel Resources, Inc.
Registrant	National Fuel Gas Company
SECI	Seneca Energy Canada Inc.
Seneca	Seneca Resources Corporation
Seneca Energy	Seneca Energy II, LLC
Supply Corporation	National Fuel Gas Supply Corporation

Regulatory Agencies

FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
NTSB	National Transportation Safety Board
NYDEC	New York State Department of Environmental Conservation
NYPSC	State of New York Public Service Commission
PaPUC	Pennsylvania Public Utility Commission
SEC	Securities and Exchange Commission

Other

2007 Form 10-K	The Company's Annual Report on Form 10-K for the year ended September 30, 2007
ARB 51	Accounting Research Bulletin No. 51, Consolidated Financial Statements
Bbl	Barrel (of oil)
Bcf	Billion cubic feet (of natural gas)
Board foot	A measure of lumber and/or timber equal to 12 inches in length by 12 inches in width by one inch in thickness.
Btu	British thermal unit; the amount of heat needed to raise the temperature of one pound of water one degree Fahrenheit.
Capital expenditure	Represents additions to property, plant, and equipment, or the amount of money a company spends to buy capital assets or upgrade its existing capital assets.
Cashout revenues	A cash resolution of a gas imbalance whereby a customer pays Supply Corporation for gas the customer receives in excess of amounts delivered into Supply Corporation's system by the customer's shipper.
Degree day	A measure of the coldness of the weather experienced, based on the extent to which the daily average temperature falls below a reference temperature, usually 65 degrees Fahrenheit.
Derivative	A financial instrument or other contract, the terms of which include an underlying variable (a price, interest rate, index rate, exchange rate, or other variable) and a notional amount (number of units, barrels, cubic feet, etc.). The terms also permit for the instrument or contract to be settled net and no initial net investment is required to enter into the financial instrument or contract. Examples include futures contracts, options, no cost collars and swaps.
Dth	Decatherm; one Dth of natural gas has a heating value of 1,000,000 British thermal units, approximately equal to the heating value of 1 Mcf of natural gas.

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GLOSSARY OF TERMS (Cont.)

Exchange Act	Securities Exchange Act of 1934, as amended
Expenditures for long-lived assets	Includes capital expenditures, stock acquisitions and/or investments in partnerships.
FIN	FASB Interpretation Number
FIN 48	FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes - an interpretation of SFAS 109
Firm transportation and/or storage	The transportation and/or storage service that a supplier of such service is obligated by contract to provide and for which the customer is obligated to pay whether or not the service is utilized.
GAAP	Accounting principles generally accepted in the United States of America
Goodwill	An intangible asset representing the difference between the fair value of a company and the price at which a company is purchased.
Hedging	A method of minimizing the impact of price, interest rate, and/or foreign currency exchange rate changes, often times through the use of derivative financial instruments.
Hub	Location where pipelines intersect enabling the trading, transportation, storage, exchange, lending and borrowing of natural gas.
Interruptible transportation and/or storage	The transportation and/or storage service that, in accordance with contractual arrangements, can be interrupted by the supplier of such service, and for which the customer does not pay unless utilized.
LIFO	Last-in, first-out
Mbbl	Thousand barrels (of oil)
Mcf	Thousand cubic feet (of natural gas)
MD&A	Management's Discussion and Analysis of Financial Condition and Results of Operations
MDth	Thousand decatherms (of natural gas)
MMcf	Million cubic feet (of natural gas)
Open Season	A bidding procedure used by pipelines to allocate firm transportation or storage capacity among prospective shippers, in which all bids submitted during a defined time period are evaluated as if they had been submitted simultaneously.
Proved developed reserves	Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.
Proved undeveloped reserves	Reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required to make these reserves productive.
PRP	Potentially responsible party
Reserves	The unproduced but recoverable oil and/or gas in place in a formation which has been proven by production.
Restructuring	Generally referring to partial "deregulation" of the utility industry by a statutory or regulatory process. Restructuring of federally regulated natural gas pipelines has resulted in the separation (or "unbundling") of gas commodity service from transportation service for wholesale and large-volume retail markets. State restructuring programs attempt to extend the same process to retail mass markets.
SAR	Stock-settled stock appreciation right
SFAS	Statement of Financial Accounting Standards
SFAS 87	Statement of Financial Accounting Standards No. 87, Employers' Accounting for Pensions
SFAS 88	Statement of Financial Accounting Standards No. 88, Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits
SFAS 106	Statement of Financial Accounting Standards No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions
SFAS 109	Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes

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GLOSSARY OF TERMS (Concl.)

SFAS 115	Statement of Financial Accounting Standards No. 115, Accounting for Certain Investments in Debt and Equity Securities
SFAS 123R	Statement of Financial Accounting Standards No. 123R, Share-Based Payment
SFAS 132R	Statement of Financial Accounting Standards No. 132R, Employers' Disclosures about Pensions and Other Postretirement Benefits
SFAS 133	Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities
SFAS 141R	Statement of Financial Accounting Standards No. 141R, Business Combinations
SFAS 157	Statement of Financial Accounting Standards No. 157, Fair Value Measurements
SFAS 158	Statement of Financial Accounting Standards No. 158, Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an Amendment of SFAS 87, 88, 106, and 132R
SFAS 159	Statement of Financial Accounting Standards No. 159, The Fair Value Option for Financial Assets and Financial Liabilities — Including an Amendment of SFAS 115
SFAS 160	Statement of Financial Accounting Standards No. 160, Noncontrolling Interests in Consolidated Financial Statements, an Amendment of ARB 51
SFAS 161	Statement of Financial Accounting Standards No. 161, Disclosures about Derivative Instruments and Hedging Activities, an Amendment of SFAS 133
Stock acquisitions	Investments in corporations.
Unbundled service	A service that has been separated from other services, with rates charged that reflect only the cost of the separated service.
VEBA	Voluntary Employees' Beneficiary Association
WNC	Weather normalization clause; a clause in utility rates which adjusts customer rates to allow a utility to recover its normal operating costs calculated at normal temperatures. If temperatures during the measured period are warmer than normal, customer rates are adjusted upward in order to recover projected operating costs. If temperatures during the measured period are colder than normal, customer rates are adjusted downward so that only the projected operating costs will be recovered.

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§ The Company has nothing to report under this item.

Reference to the "Company" in this report means the Registrant or the Registrant and its subsidiaries collectively, as appropriate in the context of the disclosure. All references to a certain year in this report are to the Company's fiscal year ended September 30 of that year, unless otherwise noted.

This Form 10-Q contains "forward-looking statements" within the meaning of Section 21E of the Securities Exchange Act of 1934. Forward-looking statements should be read with the cautionary statements and important factors included in this Form 10-Q at Item 2 — MD&A, under the heading "Safe Harbor for Forward-Looking Statements." Forward-looking statements are all statements other than statements of historical fact, including, without limitation, statements regarding future prospects, plans, performance and capital structure, anticipated capital expenditures, completion of construction projects, projections for pension and other post-retirement benefit obligations, impacts of the adoption of new accounting rules, and possible outcomes of litigation or regulatory proceedings, as well as statements that are identified by the use of the words "anticipates," "estimates," "expects," "forecasts," "intends," "plans," "predicts," "projects," "believes," "seeks," "will," "may," and similar expressions.

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Part I. Financial Information

Item 1. Financial Statements

National Fuel Gas Company
Consolidated Statements of Income and Earnings
Reinvested in the Business
(Unaudited)

(Thousands of Dollars, Except Per Common Share Amounts)	Three Months Ended June 30, 2008	2007
INCOME		
Operating Revenues	$ 548,382	$ 448,779
Operating Expenses		
Purchased Gas	272,893	219,075
Operation and Maintenance	102,602	90,390
Property, Franchise and Other Taxes	19,135	17,622
Depreciation, Depletion and Amortization	42,804	37,759
	437,434	364,846
Operating Income	110,948	83,933
Other Income (Expense):		
Income from Unconsolidated Subsidiaries	1,561	926
Interest Income	3,086	1,377
Other Income	1,649	787
Interest Expense on Long-Term Debt	(19,468)	(18,226)
Other Interest Expense	(1,199)	(1,512)
Income from Continuing Operations Before Income Taxes	96,577	67,285
Income Tax Expense	36,722	26,073
Income from Continuing Operations	59,855	41,212
Income from Discontinued Operations, Net of Tax	—	5,586
Net Income Available for Common Stock	59,855	46,798
EARNINGS REINVESTED IN THE BUSINESS		
Balance at April 1	1,008,084	834,902
	1,067,939	881,700
Share Repurchases	(17,083)	—
Dividends on Common Stock (2008 - $0.325 per share; 2007 - $0.31 per share)	(26,479)	(25,897)
Balance at June 30	$ 1,024,377	$ 855,803
Earnings Per Common Share:		
Basic:		
Income from Continuing Operations	$ 0.74	$ 0.49
Income from Discontinued Operations	—	0.07
Net Income Available for Common Stock	$ 0.74	$ 0.56
Diluted:		
Income from Continuing Operations	$ 0.72	$ 0.48
Income from Discontinued Operations	—	0.07
Net Income Available for Common Stock	$ 0.72	$ 0.55
Weighted Average Common Shares Outstanding:		
Used in Basic Calculation	81,342,788	83,483,718
Used in Diluted Calculation	83,712,193	85,668,055

See Notes to Condensed Consolidated Financial Statements

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Item 1. Financial Statements (Cont.)

National Fuel Gas Company
Consolidated Statements of Income and Earnings
Reinvested in the Business
(Unaudited)

(Thousands of Dollars, Except Per Common Share Amounts)	Nine Months Ended June 30, 2008	Nine Months Ended June 30, 2007
INCOME		
Operating Revenues	$ 2,002,503	$ 1,737,537
Operating Expenses		
Purchased Gas	1,082,340	938,918
Operation and Maintenance	325,642	305,502
Property, Franchise and Other Taxes	58,206	54,562
Depreciation, Depletion and Amortization	129,337	115,561
	1,595,525	1,414,543
Operating Income	406,978	322,994
Other Income (Expense):		
Income from Unconsolidated Subsidiaries	4,866	3,099
Interest Income	8,356	3,098
Other Income	4,982	4,028
Interest Expense on Long-Term Debt	(52,045)	(52,158)
Other Interest Expense	(4,209)	(4,877)
Income from Continuing Operations Before Income Taxes	368,928	276,184
Income Tax Expense	143,465	108,804
Income from Continuing Operations	225,463	167,380
Income from Discontinued Operations, Net of Tax	—	12,385
Net Income Available for Common Stock	225,463	179,765
EARNINGS REINVESTED IN THE BUSINESS		
Balance at October 1	983,776	786,013
	1,209,239	965,778
Share Repurchases	(106,647)	(34,351)
Cumulative Effect of the Adoption of FIN 48	(406)	—
Dividends on Common Stock (2008 - $0.945 per share; 2007 - $0.91 per share)	(77,809)	(75,624)
Balance at June 30	$ 1,024,377	$ 855,803
Earnings Per Common Share:		
Basic:		
Income from Continuing Operations	$ 2.72	$ 2.02
Income from Discontinued Operations	—	0.15
Net Income Available for Common Stock	$ 2.72	$ 2.17
Diluted:		
Income from Continuing Operations	$ 2.65	$ 1.96
Income from Discontinued Operations	—	0.15
Net Income Available for Common Stock	$ 2.65	$ 2.11
Weighted Average Common Shares Outstanding:		
Used in Basic Calculation	82,789,748	83,018,583
Used in Diluted Calculation	85,000,381	85,192,777

See Notes to Condensed Consolidated Financial Statements

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Item 1. Financial Statements (Cont.)

National Fuel Gas Company
Consolidated Balance Sheets
(Unaudited)

(Thousands of Dollars)	June 30, 2008	September 30, 2007
ASSETS		
Property, Plant and Equipment	$4,730,708	$4,461,586
Less — Accumulated Depreciation, Depletion and Amortization	1,686,616	1,583,181
	3,044,092	2,878,405
Current Assets		
Cash and Temporary Cash Investments	259,198	124,806
Cash Held in Escrow	—	61,964
Hedging Collateral Deposits	30,778	4,066
Receivables — Net of Allowance for Uncollectible Accounts of $35,588 and $28,654, Respectively	302,522	172,380
Unbilled Utility Revenue	19,580	20,682
Gas Stored Underground	53,735	66,195
Materials and Supplies — at average cost	33,310	35,669
Unrecovered Purchased Gas Costs	5,680	14,769
Other Current Assets	31,767	45,057
Deferred Income Taxes	84,297	8,550
	820,867	554,138
Other Assets		
Recoverable Future Taxes	83,453	83,954
Unamortized Debt Expense	14,501	12,070
Other Regulatory Assets	129,640	137,577
Deferred Charges	5,235	5,545
Other Investments	82,474	85,902
Investments in Unconsolidated Subsidiaries	16,916	18,256
Goodwill	5,476	5,476
Intangible Assets	26,839	28,836
Prepaid Pension and Post-Retirement Benefit Costs	56,926	61,006
Fair Value of Derivative Financial Instruments	—	9,188
Other	7,442	8,059
	428,902	455,869
Total Assets	$4,293,861	$3,888,412

See Notes to Condensed Consolidated Financial Statements

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Item 1. Financial Statements (Cont.)

National Fuel Gas Company
Consolidated Balance Sheets
(Unaudited)

(Thousands of Dollars)	June 30, 2008	September 30, 2007
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Comprehensive Shareholders' Equity		
Common Stock, $1 Par Value Authorized - 200,000,000 Shares; Issued and Outstanding – 81,473,550 Shares and 83,461,308 Shares, Respectively	$ 81,474	$ 83,461
Paid in Capital	583,693	569,085
Earnings Reinvested in the Business	1,024,377	983,776
Total Common Shareholder Equity Before Items of Other Comprehensive Loss	1,689,544	1,636,322
Accumulated Other Comprehensive Loss	(105,872)	(6,203)
Total Comprehensive Shareholders' Equity	1,583,672	1,630,119
Long-Term Debt, Net of Current Portion	999,000	799,000
Total Capitalization	2,582,672	2,429,119
Current and Accrued Liabilities		
Notes Payable to Banks and Commercial Paper	—	—
Current Portion of Long-Term Debt	100,000	200,024
Accounts Payable	162,838	109,757
Amounts Payable to Customers	12,864	10,409
Dividends Payable	26,479	25,873
Interest Payable on Long-Term Debt	15,774	18,158
Customer Advances	—	22,863
Other Accruals and Current Liabilities	136,458	36,062
Fair Value of Derivative Financial Instruments	180,255	16,200
	634,668	439,346
Deferred Credits		
Deferred Income Taxes	605,818	575,356
Taxes Refundable to Customers	14,037	14,026
Unamortized Investment Tax Credit	4,866	5,392
Cost of Removal Regulatory Liability	101,251	91,226
Other Regulatory Liabilities	95,846	76,659
Post-Retirement Liabilities	60,152	70,555
Asset Retirement Obligations	74,653	75,939
Other Deferred Credits	119,898	110,794
	1,076,521	1,019,947
Commitments and Contingencies	—	—
Total Capitalization and Liabilities	$4,293,861	$3,888,412

See Notes to Condensed Consolidated Financial Statements

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Item 1. Financial Statements (Cont.)

National Fuel Gas Company
Consolidated Statement of Cash Flows
(Unaudited)

(Thousands of Dollars)	Nine Months Ended June 30, 2008	2007
OPERATING ACTIVITIES		
Net Income Available for Common Stock	$ 225,463	$ 179,765
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:		
Depreciation, Depletion and Amortization	129,337	125,986
Deferred Income Taxes	27,603	27,107
Income from Unconsolidated Subsidiaries, Net of Cash Distributions	1,340	(1,486)
Excess Tax Benefits Associated with Stock-Based Compensation Awards	(16,275)	(13,689)
Other	(1,120)	4,722
Change in:		
Hedging Collateral Deposits	(26,712)	16,276
Receivables and Unbilled Utility Revenue	(129,102)	(43,733)
Gas Stored Underground and Materials and Supplies	14,819	34,725
Unrecovered Purchased Gas Costs	9,089	12,970
Prepayments and Other Current Assets	17,370	30,685
Accounts Payable	53,081	(12,560)
Amounts Payable to Customers	2,455	(4,738)
Customer Advances	(22,863)	(29,417)
Other Accruals and Current Liabilities	94,031	77,842
Other Assets	19,178	918
Other Liabilities	17,373	(821)
Net Cash Provided by Operating Activities	415,067	404,552
INVESTING ACTIVITIES		
Capital Expenditures	(264,728)	(206,509)
Investment in Partnership	—	(3,300)
Cash Held in Escrow	58,397	—
Net Proceeds from Sale of Oil and Gas Producing Properties	5,675	5,137
Other	(3,414)	(1,072)
Net Cash Used in Investing Activities	(204,070)	(205,744)
FINANCING ACTIVITIES		
Excess Tax Benefits Associated with Stock-Based Compensation Awards	16,275	13,689
Shares Repurchased under Repurchase Plan	(129,592)	(43,344)
Net Proceeds from Issuance of Long-Term Debt	296,655	—
Reduction of Long-Term Debt	(200,024)	(119,550)
Dividends Paid on Common Stock	(77,204)	(74,748)
Net Proceeds from Issuance of Common Stock	17,285	16,819
Net Cash Used in Financing Activities	(76,605)	(207,134)
Effect of Exchange Rates on Cash	—	1,245
Net Increase (Decrease) in Cash and Temporary Cash Investments	134,392	(7,081)
Cash and Temporary Cash Investments at October 1	124,806	69,611
Cash and Temporary Cash Investments at June 30	$ 259,198	$ 62,530

See Notes to Condensed Consolidated Financial Statements

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Item 1. Financial Statements (Cont.)

National Fuel Gas Company
Consolidated Statements of Comprehensive Income
(Unaudited)

(Thousands of Dollars)	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007
Net Income Available for Common Stock	$ 59,855	$46,798
Other Comprehensive Income (Loss), Before Tax:		
Foreign Currency Translation Adjustment	2	10,029
Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period	(1,603)	1,570
Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	(139,684)	13,343
Reclassification Adjustment for Realized Losses on Derivative Financial Instruments in Net Income	33,082	5,581
Other Comprehensive Income (Loss), Before Tax	(108,203)	30,523
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) On Securities Available for Sale Arising During the Period	(608)	562
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) On Derivative Financial Instruments Arising During the Period	(57,136)	5,433
Reclassification Adjustment for Income Tax Benefit on Realized Losses on Derivative Financial Instruments In Net Income	13,546	2,277
Income Taxes – Net	(44,198)	8,272
Other Comprehensive Income (Loss)	(64,005)	22,251
Comprehensive Income (Loss)	$ (4,150)	$69,049

(Thousands of Dollars)	Nine Months Ended June 30, 2008	Nine Months Ended June 30, 2007
Net Income Available for Common Stock	$ 225,463	$179,765
Other Comprehensive Income (Loss), Before Tax:		
Foreign Currency Translation Adjustment	(72)	6,384
Minimum Pension Liability Adjustment	—	(320)
Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period	(4,817)	2,844
Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	(208,256)	2,388
Reclassification Adjustment for Realized Losses on Derivative Financial Instruments in Net Income	45,242	7,799
Other Comprehensive Income (Loss), Before Tax	(167,903)	19,095
Income Tax Expense (Benefit) Related to Minimum Pension Liability Adjustment	—	(121)
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) On Securities Available for Sale Arising During the Period	(1,429)	1,046
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) On Derivative Financial Instruments Arising During the Period	(85,300)	669
Reclassification Adjustment for Income Tax Benefit on Realized Losses on Derivative Financial Instruments In Net Income	18,495	3,933
Income Taxes – Net	(68,234)	5,527
Other Comprehensive Income (Loss)	(99,669)	13,568
Comprehensive Income	$ 125,794	$193,333

See Notes to Condensed Consolidated Financial Statements

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Item 1. Financial Statements (Cont.)

National Fuel Gas Company
Notes to Condensed Consolidated Financial Statements
(Unaudited)

Note 1 — Summary of Significant Accounting Policies

Principles of Consolidation. The Company consolidates its majority owned entities. The equity method is used to account for minority owned entities. All significant intercompany balances and transactions are eliminated.

The preparation of the consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Reclassification. Certain prior year amounts have been reclassified to conform with current year presentation.

Earnings for Interim Periods. The Company, in its opinion, has included all adjustments that are necessary for a fair statement of the results of operations for the reported periods. The consolidated financial statements and notes thereto, included herein, should be read in conjunction with the financial statements and notes for the years ended September 30, 2007, 2006 and 2005 that are included in the Company's 2007 Form 10-K. The consolidated financial statements for the year ended September 30, 2008 will be audited by the Company's independent registered public accounting firm after the end of the fiscal year.

The earnings for the nine months ended June 30, 2008 should not be taken as a prediction of earnings for the entire fiscal year ending September 30, 2008. Most of the business of the Utility and Energy Marketing segments is seasonal in nature and is influenced by weather conditions. Due to the seasonal nature of the heating business in the Utility and Energy Marketing segments, earnings during the winter months normally represent a substantial part of the earnings that those segments are expected to achieve for the entire fiscal year. The Company's business segments are discussed more fully in Note 6 – Business Segment Information.

Consolidated Statement of Cash Flows. For purposes of the Consolidated Statement of Cash Flows, the Company considers all highly liquid debt instruments purchased with a maturity of generally three months or less to be cash equivalents. At June 30, 2008, the Company accrued $19.9 million of capital expenditures related to the construction of the Empire Connector project. This amount has been excluded from the Consolidated Statement of Cash Flows at June 30, 2008 since it represents a non-cash investing activity at that date.

Hedging Collateral Deposits. Cash held in margin accounts serves as collateral for open positions on exchange-traded futures contracts, exchange-traded options and over-the-counter swaps and collars.

Cash Held in Escrow. On August 31, 2007, the Company received approximately $232.1 million of proceeds from the sale of SECI, of which $58.0 million was placed in escrow pending receipt of a tax clearance certificate from the Canadian government. The escrow account was a Canadian dollar denominated account. On a U.S. dollar basis, the value of this account was $62.0 million at September 30, 2007. In December 2007, the Canadian government issued the tax clearance certificate, thereby releasing the proceeds from restriction as of December 31, 2007. To hedge against foreign currency exchange risk related to the cash being held in escrow, the Company held a forward contract to sell Canadian dollars. For presentation purposes on the Consolidated Statement of Cash Flows, for the nine months ended June 30, 2008, the Cash Held in Escrow line item within Investing Activities reflects the net proceeds to the Company (received on January 8, 2008) after adjusting for the impact of the foreign currency hedge.

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Item 1. Financial Statements (Cont.)

Gas Stored Underground — Current. In the Utility segment, gas stored underground – current is carried at lower of cost or market, on a LIFO method. Gas stored underground – current normally declines during the first and second quarters of the year and is replenished during the third and fourth quarters. In the Utility segment, the current cost of replacing gas withdrawn from storage is recorded in the Consolidated Statements of Income and a reserve for gas replacement is recorded in the Consolidated Balance Sheets under the caption "Other Accruals and Current Liabilities." Such reserve, which amounted to $77.9 million at June 30, 2008, is reduced to zero by September 30 of each year as the inventory is replenished.

Accumulated Other Comprehensive Income (Loss). The components of Accumulated Other Comprehensive Income (Loss), net of related tax effect, are as follows (in thousands):

	At June 30, 2008	At September 30, 2007
Funded Position of the Pension and Other Post-Retirement Benefit Plans Adjustment	$ (12,482)	$ (12,482)
Cumulative Foreign Currency Translation Adjustment	(155)	(83)
Net Unrealized Loss on Derivative Financial Instruments	(100,095)	(3,886)
Net Unrealized Gain on Securities Available for Sale	6,860	10,248
Accumulated Other Comprehensive Loss	$ (105,872)	$ (6,203)

Earnings Per Common Share. Basic earnings per common share is computed by dividing income available for common stock by the weighted average number of common shares outstanding for the period. Diluted earnings per common share reflects the potential dilution that could occur if securities or other contracts to issue common stock were exercised or converted into common stock. For purposes of determining earnings per common share, the only potentially dilutive securities the Company has outstanding are stock options and stock-settled SARs. The diluted weighted average shares outstanding shown on the Consolidated Statements of Income reflects the potential dilution as a result of these stock options and stock-settled SARs as determined using the Treasury Stock Method. Stock options and stock-settled SARs that are antidilutive are excluded from the calculation of diluted earnings per common share. For the quarter and nine months ended June 30, 2008, there were no stock options excluded as being antidilutive. There were 6,593 and 2,190 stock-settled SARs excluded as being antidilutive for the quarter and nine months ended June 30, 2008, respectively. For the quarter and nine months ended June 30, 2007, there were no stock options excluded as being antidilutive. There were 1,817 and 271 stock-settled SARs excluded as being antidilutive for the quarter and nine months ended June 30, 2007, respectively.

Share Repurchases. The Company considers all shares repurchased as cancelled shares restored to the status of authorized but unissued shares, in accordance with New Jersey law. The repurchases are accounted for on the date the share repurchase is settled as an adjustment to common stock (at par value) with the excess repurchase price allocated between paid in capital and retained earnings. Refer to Note 3 – Capitalization for further discussion of the share repurchase program.

Stock-Based Compensation. For the quarter ended June 30, 2008, the Company granted 30,000 performance-based stock-settled SARs having a weighted average exercise price of $58.99 per share. For the nine months ended June 30, 2008, the Company granted 321,000 performance-based stock-settled SARs having a weighted average exercise price of $48.46 per share. The weighted average grant date fair value of these stock-settled SARs was $12.23 per share and $9.06 per share for the quarter and nine months ended June 30, 2008, respectively. The accounting treatment for such stock-settled SARs is the same under SFAS 123R as the accounting for stock options under SFAS 123R. The stock-settled SARs granted for the quarter and nine months ended June 30, 2008 vest and become exercisable annually in one-third increments, provided that a performance condition for diluted earnings per share is met for the prior fiscal year. The weighted average grant date fair value of these stock-settled SARs

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Item 1. Financial Statements (Cont.)

granted during the quarter and nine months ended June 30, 2008 was estimated on the date of grant using the same accounting treatment that is applied for stock options under SFAS 123R, and assumes that the performance conditions specified will be achieved. If such conditions are not met, no compensation expense is recognized and any recognized compensation expense is reversed.

There were no stock options granted during the quarter and nine months ended June 30, 2008. The Company granted 25,000 restricted share awards (non-vested stock as defined in SFAS 123R) during the nine months ended June 30, 2008. The weighted average fair value of such restricted shares was $48.41 per share. There were no restricted share awards granted during the quarter ended June 30, 2008.

New Accounting Pronouncements. In September 2006, the FASB issued SFAS 157, “Fair Value Measurements”. SFAS 157 provides guidance for using fair value to measure assets and liabilities. The pronouncement serves to clarify the extent to which companies measure assets and liabilities at fair value, the information used to measure fair value, and the effect that fair-value measurements have on earnings. SFAS 157 is to be applied whenever another standard requires or allows assets or liabilities to be measured at fair value. In accordance with FASB Staff Position FAS No. 157-2, SFAS 157 is effective for financial assets and financial liabilities that are recognized or disclosed at fair value on a recurring basis as of the Company’s first quarter of fiscal 2009. The same FASB Staff Position delays the effective date for nonfinancial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value on a recurring basis, until the Company’s first quarter of fiscal 2010. The Company is currently evaluating the impact that the adoption of SFAS 157 will have on its consolidated financial statements.

In September 2006, the FASB also issued SFAS 158, “Employer’s Accounting for Defined Benefit Pension and Other Postretirement Plans” (an amendment of SFAS 87, SFAS 88, SFAS 106, and SFAS 132R). SFAS 158 requires that companies recognize a net liability or asset to report the underfunded or overfunded status of their defined benefit pension and other post-retirement benefit plans on their balance sheets, as well as recognize changes in the funded status of a defined benefit post-retirement plan in the year in which the changes occur through comprehensive income. The pronouncement also specifies that a plan’s assets and obligations that determine its funded status be measured as of the end of the Company’s fiscal year, with limited exceptions. In accordance with SFAS 158, the Company has recognized the funded status of its benefit plans and implemented the disclosure requirements of SFAS 158 at September 30, 2007. The requirement to measure the plan assets and benefit obligations as of the Company’s fiscal year-end date will be adopted by the Company by the end of fiscal 2009. Currently, the Company measures its plan assets and benefit obligations using a June 30th measurement date.

In February 2007, the FASB issued SFAS 159, “The Fair Value Option for Financial Assets and Financial Liabilities — Including an Amendment of SFAS 115.” SFAS 159 permits entities to choose to measure many financial instruments and certain other items at fair value that are not otherwise required to be measured at fair value under GAAP. A company that elects the fair value option for an eligible item will be required to recognize in current earnings any changes in that item’s fair value in reporting periods subsequent to the date of adoption. SFAS 159 is effective as of the Company’s first quarter of fiscal 2009. The Company is currently evaluating the impact, if any, that the adoption of SFAS 159 will have on its consolidated financial statements.

In December 2007, the FASB issued SFAS 141R, “Business Combinations.” SFAS 141R will significantly change the accounting for business combinations in a number of areas including the treatment of contingent consideration, contingencies, acquisition costs, in process research and development and restructuring costs. In addition, under SFAS 141R, changes in deferred tax asset valuation allowances and acquired income tax uncertainties in a business combination after the measurement period will impact income tax expense. SFAS 141R is effective as of the Company’s first quarter of fiscal 2010.

In December 2007, the FASB issued SFAS 160, “Noncontrolling Interests in Consolidated Financial Statements, an Amendment of ARB 51.” SFAS 160 will change the accounting and reporting for minority interests, which will be recharacterized as noncontrolling interests (NCI) and classified as a

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component of equity. This new consolidation method will significantly change the accounting for transactions with minority interest holders. SFAS 160 is effective as of the Company's first quarter of fiscal 2010. The Company currently does not have any NCI.

In March 2008, the FASB issued SFAS 161, "Disclosures about Derivative Instruments and Hedging Activities, an Amendment of SFAS 133." SFAS 161 requires entities to provide enhanced disclosures related to an entity's derivative instruments and hedging activities in order to enable investors to better understand how derivative instruments and hedging activities impact an entity's financial reporting. The additional disclosures include how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for under SFAS 133 and its related interpretations, and how derivative instruments and related hedged items affect an entity's financial position, financial performance, and cash flows. SFAS 161 is effective as of the Company's second quarter of fiscal 2009. The Company is currently evaluating the impact that the adoption of SFAS 161 will have on its disclosures in its notes to its consolidated financial statements.

Note 2 — Income Taxes

The components of federal, state and foreign income taxes included in the Consolidated Statements of Income are as follows (in thousands):

	Nine Months Ended June 30, 2008	Nine Months Ended June 30, 2007
Operating Expenses:		
Current Income Taxes		
Federal	$ 92,384	$ 65,629
State	23,388	19,259
Foreign	90	22
Deferred Income Taxes		
Federal	18,906	18,221
State	8,697	5,270
Foreign	—	3,616
	143,465	112,017
Deferred Investment Tax Credit	(523)	(523)
Total Income Taxes	$142,942	$111,494
Presented as Follows:		
Other Income	$ (523)	$ (523)
Income Tax Expense – Continuing Operations	143,465	108,804
Income from Discontinued Operations	—	3,213
Total Income Taxes	$142,942	$111,494

The U.S. and foreign components of income before income taxes are as follows (in thousands):

	Nine Months Ended June 30, 2008	Nine Months Ended June 30, 2007
U.S.	$368,191	$275,196
Foreign	214	16,063
	$368,405	$291,259

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Item 1. Financial Statements (Cont.)

Total income taxes as reported differ from the amounts that were computed by applying the federal income tax rate to income before income taxes. The following is a reconciliation of this difference (in thousands):

	Nine Months Ended June 30, 2008	2007
Income Tax Expense, Computed at Statutory Rate of 35%	$128,942	$101,941
Increase (Reduction) in Taxes Resulting From:		
State Income Taxes	20,855	15,944
Miscellaneous	(6,855)	(6,391)
Total Income Taxes	$142,942	$111,494

Significant components of the Company's deferred tax liabilities and assets are as follows (in thousands):

	At June 30, 2008	At September 30, 2007
Deferred Tax Liabilities:		
Property, Plant and Equipment	$ 669,079	$ 612,648
Other	38,451	61,616
Total Deferred Tax Liabilities	707,530	674,264
Deferred Tax Assets:		
Fair Value of Derivative Instruments and Securities	(65,192)	—
Other	(120,817)	(107,458)
Total Deferred Tax Assets	(186,009)	(107,458)
Total Net Deferred Income Taxes	$ 521,521	$ 566,806
Presented as Follows:		
Net Deferred Tax Asset – Current	$ (84,297)	$ (8,550)
Net Deferred Tax Liability – Non-Current	605,818	575,356
Total Net Deferred Income Taxes	$ 521,521	$ 566,806

Regulatory liabilities representing the reduction of previously recorded deferred income taxes with rate-regulated activities that are expected to be refundable to customers amounted to $14.0 million at both June 30, 2008 and September 30, 2007. Also, regulatory assets representing future amounts collectible from customers, corresponding to additional deferred income taxes not previously recorded because of prior ratemaking practices, amounted to $83.5 million and $84.0 million at June 30, 2008 and September 30, 2007, respectively.

The Company adopted FIN 48 on October 1, 2007. As of the date of adoption, a cumulative effect adjustment was recorded that resulted in a decrease to retained earnings of $0.4 million. Upon adoption, the unrecognized tax benefits were $1.7 million, all of which would impact the effective tax rate (net of federal benefit) if recognized. There has been no change in the balance of unrecognized tax benefits through June 30, 2008 and the Company does not anticipate any significant change in this liability over the next twelve months.

The Company recognizes estimated interest payable relating to income taxes in Other Interest Expense and estimated penalties relating to income taxes in Other Income. The Company has accrued interest of $0.5 million through June 30, 2008 and has not accrued any penalties.

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The Company files U.S. federal and various state income tax returns. The Internal Revenue Service (IRS) is currently conducting an examination of the Company for fiscal 2008 in accordance with the Compliance Assurance Process ("CAP"). The CAP audit employs a real time review of the Company's books and tax records by the IRS that is intended to permit issue resolution prior to the filing of the tax return. The IRS has issued a Full Acceptance Letter for the fiscal 2007 CAP audit, and is in the process of completing the post-filing review of this return. While the federal statute of limitations remains open for fiscal 2005 and later years, IRS examinations for years prior to fiscal 2007 have been completed and the Company believes such years are effectively settled.

For the major states in which the various subsidiary companies operate, the earliest tax year open for examination is as follows:

New York	Fiscal 2002
Pennsylvania	Fiscal 2003
California	Fiscal 2003
Texas	Fiscal 2003

Note 3 — Capitalization

Common Stock. During the nine months ended June 30, 2008, the Company issued 884,644 original issue shares of common stock as a result of stock option exercises and 25,000 original issue shares for restricted stock awards (non-vested stock as defined in SFAS 123R). The Company also issued 7,200 original issue shares of common stock to the eight non-employee directors of the Company who receive compensation under the Company's Retainer Policy for Non-Employee Directors, as partial consideration for the directors' services during the nine months ended June 30, 2008. Holders of stock options or restricted stock will often tender shares of common stock to the Company for payment of option exercise prices and/or applicable withholding taxes. During the nine months ended June 30, 2008, 72,205 shares of common stock were tendered to the Company for such purposes. The Company considers all shares tendered as cancelled shares restored to the status of authorized but unissued shares, in accordance with New Jersey law.

On December 8, 2005, the Company's Board of Directors authorized the Company to implement a share repurchase program, whereby the Company may repurchase outstanding shares of common stock, up to an aggregate amount of 8 million shares in the open market or through privately negotiated transactions. During the nine months ended June 30, 2008, the Company repurchased 2,832,397 shares for $129.6 million under this program, funded with cash provided by operating activities. Since the repurchase program was implemented, the Company has repurchased 6,667,275 shares for $262.8 million.

Shareholder Rights Plan. On February 21, 2008, the Board of Directors of the Company approved amendments to the Company's Amended and Restated Rights Agreement (the "Rights Agreement"). The amendments modify the rights of holders of the Company's Common Stock Purchase Rights (the "Rights"). The principal amendments are an extension of the expiration date of the Rights Agreement from July 31, 2008 to July 31, 2018 and an increase in the exercise price of the Rights from $65 to $150 per full share. The Board also approved amendments to the Rights Agreement (i) to provide that the phrase "then outstanding," when used with reference to a person's beneficial ownership of securities of the Company, means the number of securities then issued and outstanding together with the number of such securities not then actually issued and outstanding which such person would be deemed to own beneficially under the Rights Agreement, including, among other things, certain derivative or synthetic arrangements having characteristics of a long position in the Company's common stock, (ii) to eliminate certain restrictive covenants that would have applied to the Company after the distribution date of the Rights, and (iii) to clarify and update the Rights Agreement in various respects. The Company, on July 11, 2008, entered into an amended and restated Rights Agreement, reflecting the changes described in this paragraph, with the Bank of New York, as Rights Agent, and on July 15, 2008, filed with the SEC copies of that agreement as exhibits to Forms 8-A and Form 8-K.

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Item 1. Financial Statements (Cont.)

Long-Term Debt. In April 2008, the Company issued $300.0 million of 6.50% senior, unsecured notes in a private placement exempt from registration under the Securities Act of 1933. The notes have a term of 10 years, with a maturity date in April 2018. The holders of the notes may require the Company to repurchase their notes in the event of a change in control at a price equal to 101% of the principal amount. In addition, the Company is required to either offer to exchange the notes for substantially similar notes as are registered under the Securities Act of 1933 or, in certain circumstances, register the resale of the notes. The Company used $200.0 million of the proceeds to refund $200.0 million of 6.303% medium-term notes that subsequently matured on May 27, 2008.

Note 4 — Commitments and Contingencies

Environmental Matters. The Company is subject to various federal, state and local laws and regulations relating to the protection of the environment. The Company has established procedures for the ongoing evaluation of its operations to identify potential environmental exposures and comply with regulatory policies and procedures. It is the Company's policy to accrue estimated environmental clean-up costs (investigation and remediation) when such amounts can reasonably be estimated and it is probable that the Company will be required to incur such costs.

As disclosed in Note H of the Company's 2007 Form 10-K, the Company received, in 1998 and again in October 1999, notice that the NYDEC believes the Company is responsible for contamination discovered at a former manufactured gas plant site located in New York for which the Company had not been named as a PRP. In February 2007, the NYDEC identified the Company as a PRP for the site and issued a proposed remedial action plan. The NYDEC estimated clean-up costs under its proposed remedy to be $8.9 million if implemented. Although the Company commented to the NYDEC that the proposed remedial action plan contained a number of material errors, omissions and procedural defects, the NYDEC, in a March 2007 Record of Decision, selected the remedy it had previously proposed. In July 2007, the Company appealed the NYDEC's Record of Decision to the New York State Supreme Court, Albany County. The Court dismissed the appeal in January 2008. The Company filed a notice of appeal in February 2008. In July 2008, the Company withdrew its appeal and agreed to the terms of an Order on Consent issued by the NYDEC. Pursuant to the order, the Company will remediate the site consistent with the remedy selected in the NYDEC's Record of Decision. The Company will also reimburse the NYDEC in the amount of approximately $1.5 million for costs incurred in connection with the site from 1998 through May 30, 2007. The Company acknowledged that additional charges related to the site will be billed to the Company at a later date, including costs incurred by the NYDEC after May 30, 2007 and any costs incurred by the New York Department of Health. The Company has not received any estimates of such additional costs. The Company has recorded an estimated minimum liability of $10.4 million associated with this site.

At June 30, 2008, the Company has estimated its remaining clean-up costs related to former manufactured gas plant sites and third party waste disposal sites (including the former manufactured gas plant site discussed above) will be in the range of $13.5 million to $17.2 million. The minimum estimated liability of $13.5 million has been recorded on the Consolidated Balance Sheet at June 30, 2008, including the $10.4 million discussed above. The Company expects to recover its environmental clean-up costs from a combination of rate recovery and deferred insurance proceeds that are currently recorded as a regulatory liability on the Consolidated Balance Sheet.

The Company is currently not aware of any material additional exposure to environmental liabilities. However, changes in environmental regulations or other factors could adversely impact the Company.

Other. The Company is involved in other litigation and regulatory matters arising in the normal course of business. These other matters may include, for example, negligence claims and tax, regulatory or other governmental audits, inspections, investigations and other proceedings. These matters may involve state and federal taxes, safety, compliance with regulations, rate base, cost of service and purchased gas cost issues, among other things. While these normal-course matters could have a material effect on earnings

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Item 1. Financial Statements (Cont.)

and cash flows in the quarterly and annual period in which they are resolved, they are not expected to change materially the Company's present liquidity position, nor to have a material adverse effect on the financial condition of the Company.

Note 5 — Discontinued Operations

On August 31, 2007, the Company, in its Exploration and Production segment, completed the sale of SECI, Seneca's wholly owned subsidiary that operated in Canada. The Company received approximately $232.1 million of proceeds from the sale, of which $58.0 million was placed in escrow pending receipt of a tax clearance certificate from the Canadian government. In December 2007, the Canadian government issued the tax clearance certificate, thereby releasing the proceeds from restriction as of December 31, 2007. The sale resulted in the recognition of a gain of approximately $120.3 million, net of tax, during the fourth quarter of 2007. SECI is engaged in the exploration for, and the development and purchase of, natural gas and oil reserves in the provinces of Alberta, Saskatchewan and British Columbia in Canada. The decision to sell was based on lower than expected returns from the Canadian oil and gas properties combined with difficulty in finding significant new reserves. Seneca will continue its exploration and development activities in Appalachia, the Gulf of Mexico, and California. As a result of the decision to sell SECI, the Company began presenting all SECI operations as discontinued operations during the fourth quarter of 2007.

The following is selected financial information of the discontinued operations for SECI:

(Thousands)	Three Months Ended June 30, 2007	Nine Months Ended June 30, 2007
Operating Revenues	$14,366	$42,004
Operating Expenses	9,915	27,205
Operating Income	4,451	14,799
Interest Income	272	799
Income before Income Taxes	4,723	15,598
Income Tax Expense (Benefit)	(863)	3,213
Income from Discontinued Operations	$ 5,586	$12,385

Note 6 — Business Segment Information

The Company has five reportable segments: Utility, Pipeline and Storage, Exploration and Production, Energy Marketing, and Timber. The division of the Company's operations into the reportable segments is based upon a combination of factors including differences in products and services, regulatory environment and geographic factors.

The data presented in the tables below reflect the reportable segments and reconciliations to consolidated amounts. As stated in the 2007 Form 10-K, the Company evaluates segment performance based on income before discontinued operations, extraordinary items and cumulative effects of changes in accounting (where applicable). When these items are not applicable, the Company evaluates performance based on net income. There have been no changes in the basis of segmentation nor in the basis of measuring segment profit or loss from those used in the Company's 2007 Form 10-K. There have been no material changes in the amount of assets for any operating segment from the amounts disclosed in the 2007 Form 10-K.

Item 1. Financial Statements (Cont.)

Quarter Ended June 30, 2008 (Thousands)	Utility	Pipeline and Storage	Exploration and Production	Energy Marketing	Timber	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
Revenue from External Customers	$217,339	$32,054	$126,154	$162,129	$10,114	$547,790	$ 395	$ 197	$ 548,382
Intersegment Revenues	$ 3,154	$20,131	$ —	$ —	$ —	$ 23,285	$4,439	$ (27,724)	$ —
Segment Profit (Loss): Net Income (Loss)	$ 7,848	$12,534	$ 39,791	$ 478	$ (2,066)	$ 58,585	$1,106	$ 164	$ 59,855

Nine Months Ended June 30, 2008 (Thousands)	Utility	Pipeline and Storage	Exploration and Production	Energy Marketing	Timber	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
Revenue from External Customers	$1,067,194	$101,871	$348,829	$440,111	$40,438	$1,998,443	$ 3,564	$ 496	$2,002,503
Intersegment Revenues	$ 13,567	$ 61,340	$ —	$ —	$ —	$ 74,907	$10,251	$ (85,158)	$ —
Segment Profit (Loss): Net Income (Loss)	$ 62,228	$ 40,931	$108,385	$ 7,079	$ 2,214	$ 220,837	$ 5,137	$ (511)	$ 225,463

Quarter Ended June 30, 2007 (Thousands)	Utility	Pipeline and Storage	Exploration and Production	Energy Marketing	Timber	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
Revenue from External Customers	$210,604	$30,128	$80,028	$113,380	$13,131	$447,271	$1,308	$ 200	$ 448,779
Intersegment Revenues	$ 2,586	$20,332	$ —	$ —	$ —	$ 22,918	$2,253	$ (25,171)	$ —
Segment Profit (Loss): Income (Loss) from Continuing Operations	$ 3,705	$15,451	$18,849	$ 1,233	$ (364)	$ 38,874	$ 458	$ 1,880	$ 41,212

Nine Months Ended June 30, 2007 (Thousands)	Utility	Pipeline and Storage	Exploration and Production	Energy Marketing	Timber	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
Revenue from External Customers	$1,000,860	$94,889	$233,708	$360,036	$43,079	$1,732,572	$4,387	$ 578	$1,737,537
Intersegment Revenues	$ 12,556	$61,585	$ —	$ —	$ —	$ 74,141	$6,540	$ (80,681)	$ —
Segment Profit: Income from Continuing Operations	$ 54,322	$43,075	$ 52,573	$ 8,431	$ 3,053	$ 161,454	$1,911	$ 4,015	$ 167,380

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Item 1. Financial Statements (Cont.)

Note 7 — Intangible Assets

The components of the Company's intangible assets were as follows (in thousands):

	At June 30, 2008			At September 30, 2007
	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Net Carrying Amount
Intangible Assets Subject to Amortization:				
Long-Term Transportation Contracts	$ 8,580	$ (5,791)	$ 2,789	$ 3,591
Long-Term Gas Purchase Contracts	31,864	(7,814)	24,050	25,245
	$40,444	$(13,605)	$26,839	$ 28,836

Aggregate Amortization Expense:	
(Thousands)	
Three Months Ended June 30, 2008	$ 666
Three Months Ended June 30, 2007	$ 666
Nine Months Ended June 30, 2008	$ 1,997
Nine Months Ended June 30, 2007	$ 1,997

The gross carrying amount of intangible assets subject to amortization at June 30, 2008 remained unchanged from September 30, 2007. The only activity with regard to intangible assets subject to amortization was amortization expense as shown in the table above. Amortization expense for the long-term transportation contracts is estimated to be $0.3 million for the remainder of 2008 and $0.5 million for fiscal 2009. Amortization expense for transportation contracts is estimated to be $0.4 million annually for 2010, 2011 and 2012. Amortization expense for the long-term gas purchase contracts is estimated to be $0.4 million for the remainder of 2008 and $1.6 million annually for 2009, 2010, 2011 and 2012.

Note 8 — Retirement Plan and Other Post-Retirement Benefits

Components of Net Periodic Benefit Cost (in thousands):

	Retirement Plan		Other Post-Retirement Benefits	
Three months ended June 30,	2008	2007	2008	2007
Service Cost	$ 3,149	$ 3,225	$ 1,276	$ 1,403
Interest Cost	11,237	11,087	6,770	6,800
Expected Return on Plan Assets	(13,750)	(12,809)	(8,428)	(6,740)
Amortization of Prior Service Cost	202	220	1	1
Amortization of Transition Amount	—	—	1,782	1,782
Amortization of Losses	2,766	3,382	732	2,053
Net Amortization and Deferral for Regulatory Purposes (Including Volumetric Adjustments) (1)	783	(344)	4,354	3,382
Net Periodic Benefit Cost	$ 4,387	$ 4,761	$ 6,487	$ 8,681

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Item 1. Financial Statements (Cont.)

	Retirement Plan		Other Post-Retirement Benefits	
Nine months ended June 30,	2008	2007	2008	2007
Service Cost	$ 9,448	$ 9,674	$ 3,828	$ 4,210
Interest Cost	33,712	33,263	20,311	20,399
Expected Return on Plan Assets	(41,250)	(38,427)	(25,286)	(20,220)
Amortization of Prior Service Cost	606	661	3	3
Amortization of Transition Amount	—	—	5,346	5,345
Amortization of Losses	8,298	10,146	2,195	6,160
Net Amortization and Deferral for Regulatory Purposes (Including Volumetric Adjustments) (1)	7,597	3,885	20,028	16,453
Net Periodic Benefit Cost	$ 18,411	$ 19,202	$ 26,425	$ 32,350

(1) The Company's policy is to record retirement plan and other post-retirement benefit costs in the Utility segment on a volumetric basis to reflect the fact that the Utility segment experiences higher throughput of natural gas in the winter months and lower throughput of natural gas in the summer months.

Employer Contributions. During the nine months ended June 30, 2008, the Company contributed $3.8 million to its retirement plan and $25.3 million to its VEBA trusts and 401(h) accounts in its other post-retirement benefit plan. In the remainder of 2008, the Company expects to contribute $12.2 million to its retirement plan and $3.8 million to its VEBA trusts and 401(h) accounts in its other post-retirement benefit plan.

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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

OVERVIEW

The Company is a diversified energy company and reports its operating results in five reportable business segments. For the quarter ended June 30, 2008 compared to the quarter ended June 30, 2007, the Company has experienced an increase in earnings of $13.1 million, primarily due to higher earnings in the Exploration and Production segment. The Utility segment and the All Other category also contributed to the increase in earnings. These earnings increases discussed above were slightly offset by lower earnings in the Pipeline and Storage and Energy Marketing segments as well as in the Corporate category, combined with a higher loss in the Timber segment. For the nine months ended June 30, 2008 compared to the nine months ended June 30, 2007, the Company experienced an increase in earnings of $45.7 million, due primarily to higher earnings in the Exploration and Production segment. The Utility segment and the All Other category also contributed to the increase in earnings. These earnings increases discussed above were slightly offset by lower earnings in the Pipeline and Storage, Energy Marketing, and Timber segments as well as in the Corporate category. The Company's earnings are discussed further in the Results of Operations section that follows.

From a capital resources and liquidity perspective, the Company spent $284.6 million on capital expenditures during the nine months ended June 30, 2008, with approximately 49% being spent in the Exploration and Production segment, 37% in the Pipeline and Storage segment and 14% in the Utility segment. The amounts spent in the various segments reflect the Company's belief that the Exploration and Production segment and the Pipeline and Storage segment currently provide the best earnings growth opportunities for shareholders. In the Exploration and Production segment, the Company's principal focus continues to be the development of its nearly one million acres in the Appalachian region along with continued exploration and development in the Gulf and West Coast regions. In the Pipeline and Storage segment, the majority of the expenditures were for construction costs of the Empire Connector project. The project is on schedule to be completed by the planned in-service date of November 2008, although the actual in-service date will depend upon the completion of the Millennium Pipeline. This project and other capital expenditures are discussed further in the Capital Resources and Liquidity section that follows.

The Company regularly considers the repurchase of outstanding shares of common stock under a share repurchase program authorized by the Company's Board of Directors. The program authorizes the Company to repurchase up to an aggregate amount of 8 million shares. Through June 30, 2008, the Company had repurchased 6,667,275 shares for $262.8 million under this program, including 2,832,397 shares for $129.6 million during the nine months ended June 30, 2008. These matters are discussed further in the Capital Resources and Liquidity section that follows.

The Company has begun to explore the sale of Horizon LFG, a New York corporation that owns and operates short-distance landfill gas pipeline companies that are engaged in the purchase, sale and transportation of landfill gas in Ohio, Michigan, Kentucky, Missouri, Maryland and Indiana. Horizon LFG is included in the Company's All Other category. The Company is also exploring the sale of Horizon Power's unconsolidated subsidiaries. This includes ESNE, which generates electricity from an 80-megawatt, combined cycle, natural gas-fired power plant in North East, Pennsylvania, as well as Seneca Energy and Model City, which generate and sell electricity using methane gas obtained from landfills owned by outside parties.

CRITICAL ACCOUNTING ESTIMATES

For a complete discussion of critical accounting estimates, refer to "Critical Accounting Estimates" in Item 7 of the Company's 2007 Form 10-K. There have been no subsequent changes to that disclosure.

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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations (Cont.)

RESULTS OF OPERATIONS

Earnings

The Company's earnings were $59.9 million for the quarter ended June 30, 2008 compared to earnings of $46.8 million for the quarter ended June 30, 2007. As previously discussed, the Company has presented its Canadian operations in the Exploration and Production segment (in conjunction with the sale of SECI) as discontinued operations. The Company's earnings from continuing operations were $59.9 million for the quarter ended June 30, 2008 compared to earnings from continuing operations of $41.2 million for the quarter ended June 30, 2007. The increase in earnings from continuing operations of $18.7 million is primarily the result of higher earnings in the Exploration and Production segment. The Utility segment and the All Other category also contributed to the increase in earnings. These earnings increases discussed above were slightly offset by lower earnings in the Pipeline and Storage and Energy Marketing segments, as well as in the Corporate category, combined with a higher loss in the Timber segment.

The Company's earnings were $225.5 million for the nine months ended June 30, 2008 compared to earnings of $179.8 million for the nine months ended June 30, 2007. The Company's earnings from continuing operations were $225.5 million for the nine months ended June 30, 2008 compared to earnings from continuing operations of $167.4 million for the nine months ended June 30, 2007. The increase in earnings from continuing operations of $58.1 million is primarily the result of higher earnings in the Exploration and Production segment. The Utility segment and the All Other category also contributed to the increase in earnings. These earnings increases discussed above were slightly offset by lower earnings in the Pipeline and Storage, Energy Marketing, and Timber segments as well as in the Corporate category.

Additional discussion of earnings in each of the business segments can be found in the business segment information that follows. Note that all amounts used in the earnings discussions are after tax amounts, unless otherwise noted.

Earnings (Loss) by Segment

	Three Months Ended June 30,			Nine Months Ended June 30,		
(Thousands)	2008	2007	Increase/ (Decrease)	2008	2007	Increase/ (Decrease)
Utility	$ 7,848	$ 3,705	$ 4,143	$ 62,228	$ 54,322	$ 7,906
Pipeline and Storage	12,534	15,451	(2,917)	40,931	43,075	(2,144)
Exploration and Production	39,791	18,849	20,942	108,385	52,573	55,812
Energy Marketing	478	1,233	(755)	7,079	8,431	(1,352)
Timber	(2,066)	(364)	(1,702)	2,214	3,053	(839)
Total Reportable Segments	58,585	38,874	19,711	220,837	161,454	59,383
All Other	1,106	458	648	5,137	1,911	3,226
Corporate	164	1,880	(1,716)	(511)	4,015	(4,526)
Total Earnings from Continuing Operations	59,855	41,212	18,643	225,463	167,380	58,083
Earnings from Discontinued Operations	—	5,586	(5,586)	—	12,385	(12,385)
Total Consolidated	$59,855	$46,798	$ 13,057	$225,463	$179,765	$ 45,698

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Utility

Utility Operating Revenues

	Three Months Ended June 30,			Nine Months Ended June 30,		
(Thousands)	2008	2007	Increase/ (Decrease)	2008	2007	Increase/ (Decrease)
Retail Sales Revenues:						
Residential	$153,058	$158,922	$ (5,864)	$ 793,124	$ 778,572	$ 14,552
Commercial	20,459	24,380	(3,921)	124,582	127,485	(2,903)
Industrial	1,178	1,432	(254)	6,754	7,081	(327)
	174,695	184,734	(10,039)	924,460	913,138	11,322
Transportation	21,584	21,017	567	97,345	86,358	10,987
Off-System Sales	20,540	3,727	16,813	48,606	3,727	44,879
Other	3,674	3,712	(38)	10,350	10,193	157
	$220,493	$213,190	$ 7,303	$1,080,761	$1,013,416	$ 67,345

Utility Throughput

	Three Months Ended June 30,			Nine Months Ended June 30,		
(MMcf)	2008	2007	Increase/ (Decrease)	2008	2007	Increase/ (Decrease)
Retail Sales:						
Residential	8,618	10,679	(2,061)	53,881	56,729	(2,848)
Commercial	1,334	1,836	(502)	9,197	10,132	(935)
Industrial	77	113	(36)	524	628	(104)
	10,029	12,628	(2,599)	63,602	67,489	(3,887)
Transportation	12,086	12,981	(895)	55,966	53,556	2,410
Off-System Sales	1,711	467	1,244	4,790	467	4,323
	23,826	26,076	(2,250)	124,358	121,512	2,846

Degree Days

				Percent Colder (Warmer) Than	
	Normal	2008	2007	Normal	Prior Year
Three Months Ended June 30					
Buffalo	927	817	921	(11.9)	(11.3)
Erie	885	762	900	(13.9)	(15.3)
Nine Months Ended June 30					
Buffalo	6,551	6,175	6,195	(5.7)	(0.3)
Erie	6,142	5,737	5,930	(6.6)	(3.3)

2008 Compared with 2007

Operating revenues for the Utility segment increased $7.3 million for the quarter ended June 30, 2008 as compared with the quarter ended June 30, 2007. The increase for the quarter is primarily attributable to a $16.8 million increase in off-system sales revenue (see discussion below) partially offset by a $10.0 million decrease in retail sales revenue. The $10.0 million decrease in retail gas sales revenues was a function of lower throughput volumes, partially offset by the recovery of higher gas costs (subject to certain timing variations, gas costs are recovered dollar for dollar in revenues) coupled with the revenue impact of a rate design change. In December 2007, the NYPSC issued an order providing for an annual rate increase of $1.8 million beginning December 28, 2007. As part of this rate order, a rate design change was adopted that shifts a greater amount of cost recovery into the minimum bill amount,

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thus spreading the recovery of such costs more evenly throughout the year. This rate design change resulted in lower retail and transportation revenues in the quarter ended March 31, 2008 compared to the quarter ended March 31, 2007. The rate order caused higher retail and transportation revenues in the quarter ended June 30, 2008 compared to the quarter ended June 30, 2007. However, on a year-to-date basis, retail and transportation revenues for the nine months ended June 30, 2008 (exclusive of the impact of higher gas costs) are still lower than the nine months ended June 30, 2007 as a result of the rate design change. It is expected that there will also be an increase in retail and transportation revenue in the fourth quarter of this year compared to the prior year as a result of the rate design change.

Operating revenues for the Utility segment increased $67.3 million for the nine months ended June 30, 2008 as compared with the nine months ended June 30, 2007. This increase largely resulted from a $44.9 million increase in off-system sales revenue (see discussion below) and an $11.3 million increase in retail sales revenue coupled with an $11.0 million increase in transportation revenues. The increase in retail gas sales revenues for the Utility segment was largely a function of higher gas costs (subject to certain timing variations, gas costs are recovered dollar for dollar in revenues) partially offset by the revenue impact of the rate design change discussed above. The increase in transportation revenues was primarily due to a 2.4 Bcf increase in transportation throughput, largely due to the migration of customers from retail sales to transportation service.

As reported in 2006, on November 17, 2006, the U.S. Court of Appeals vacated and remanded the FERC's Order No. 2004 regarding affiliate standards of conduct with respect to natural gas pipelines. The Court's decision became effective on January 5, 2007, and on January 9, 2007, the FERC issued Order No. 690, its Interim Rule, designed to respond to the Court's decision. In Order No. 690, as clarified by the FERC on March 21, 2007, the FERC readopted, on an interim basis, certain provisions that existed prior to the issuance of Order No. 2004 that had made it possible for the Utility segment to engage in certain off-system sales without triggering the adverse consequences that would otherwise arise under the Order No. 2004 standards of conduct. As a result, the Utility segment resumed engaging in off-system sales on non-affiliated pipelines as of May 2007. Total off-system sales revenues for the quarters ended June 30, 2008 and June 30, 2007 amounted to $20.5 million and $3.7 million, respectively. Total off-system sales revenues for the nine months ended June 30, 2008 and June 30, 2007 amounted to $48.6 million and $3.7 million, respectively. Due to profit sharing with retail customers, the margins resulting from off-system sales are minimal and there was not a material impact to margins for the quarters and nine months ended June 30, 2008 and 2007.

The Utility segment's earnings for the quarter ended June 30, 2008 were $7.8 million, an increase of $4.1 million compared to earnings of $3.7 million for the quarter ended June 30, 2007. In the New York jurisdiction, earnings increased by $4.4 million. As a result of the rate design change in the New York jurisdiction, earnings for the third quarter of fiscal 2008 increased by $1.7 million from the third quarter of fiscal 2007. A $1.7 million decrease in operating costs (mostly due to lower post-retirement benefit costs), a non-recurring regulatory adjustment made in 2007 ($0.9 million), and the positive impact of a lower effective tax rate ($0.8 million) also contributed to the overall increase in earnings for the New York jurisdiction. These increases were partly offset by lower usage per account ($1.0 million). In the Pennsylvania jurisdiction, earnings decreased by $0.3 million due primarily to lower usage per account offset in part by lower operating costs and lower interest expense.

The impact of weather variations on earnings in the New York jurisdiction is mitigated by that jurisdiction's weather normalization clause (WNC). The WNC in New York, which covers the eight-month period from October through May, has had a stabilizing effect on earnings for the New York jurisdiction. For the quarter ended June 30, 2008, the WNC preserved earnings of approximately $0.4 million, as weather was warmer than normal for the period. For the quarter ended June 30, 2007, the WNC did not have a significant impact on earnings as the weather was close to normal.

The Utility segment's earnings for the nine months ended June 30, 2008 were $62.2 million; an increase of $7.9 million when compared with earnings of $54.3 million for the nine months ended June 30, 2007. In the New York jurisdiction, earnings increased $5.2 million. Lower operating costs of $4.5 million (mostly due to lower post-retirement benefit costs and lower bad debt expense), the positive impact of non-recurring regulatory adjustments made in 2007 ($0.9 million), the positive impact of a lower effective

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tax rate ($0.9 million), a routine regulatory adjustment ($0.7 million), lower property taxes ($0.7 million), and higher customer usage per account ($0.3 million) also contributed to the overall increase in earnings for the New York jurisdiction. These increases were partly offset by a $3.1 million decrease in earnings associated with the rate design change discussed above. In the Pennsylvania jurisdiction, earnings increased $2.7 million due primarily to a base rate increase that became effective in January 2007 ($2.6 million), higher usage per account ($0.9 million), and a decrease in operating costs of $1.1 million (mostly due to lower bad debt expense). These increases were partially offset by the negative earnings impact associated with warmer weather ($1.5 million).

For the nine months ended June 30, 2008, the WNC preserved earnings of approximately $2.5 million, as the weather was warmer than normal. For the nine months ended June 30, 2007, the WNC preserved earnings of approximately $2.3 million, as the weather was also warmer than normal.

Pipeline and Storage

Pipeline and Storage Operating Revenues

	Three Months Ended June 30,			Nine Months Ended June 30,		
(Thousands)	2008	2007	Increase/ (Decrease)	2008	2007	Increase
Firm Transportation	$29,020	$28,556	$ 464	$ 93,427	$ 89,819	$ 3,608
Interruptible Transportation	1,151	1,170	(19)	3,237	3,071	166
	30,171	29,726	445	96,664	92,890	3,774
Firm Storage Service	16,754	17,002	(248)	50,325	50,194	131
Other	5,260	3,732	1,528	16,222	13,390	2,832
	$52,185	$50,460	$ 1,725	$163,211	$156,474	$ 6,737

Pipeline and Storage Throughput

	Three Months Ended June 30,			Nine Months Ended June 30,		
(MMcf)	2008	2007	Decrease	2008	2007	Increase
Firm Transportation	68,263	78,455	(10,192)	283,104	273,513	9,591
Interruptible Transportation	1,540	1,670	(130)	3,844	3,597	247
	69,803	80,125	(10,322)	286,948	277,110	9,838

2008 Compared with 2007

Operating revenues for the Pipeline and Storage segment increased $1.7 million for the quarter ended June 30, 2008 as compared with the quarter ended June 30, 2007. The increase was primarily due to increased efficiency gas revenues ($1.9 million) reported as part of other revenues in the table above. The majority of this increase was due to higher gas prices in the quarter ended June 30, 2008 as compared with the quarter ended June 30, 2007. Overall, throughput decreased during the quarter ended June 30, 2008 as compared with the quarter ended June 30, 2007. While Supply Corporation's and Empire's transportation volumes decreased during the quarter, volume fluctuations generally do not have a significant impact on revenues as a result of Supply Corporation's straight fixed-variable rate design and Empire's modified fixed-variable rate design.

Operating revenues for the nine months ended June 30, 2008 increased $6.7 million as compared with the nine months ended June 30, 2007. The increase was primarily due to a $3.8 million increase in transportation revenue primarily due to the fact that the Pipeline and Storage segment was able to renew existing contracts at higher rates due to favorable market conditions related to the demand for transportation service associated with storage. In addition, there was a $3.1 million increase in efficiency gas revenues reported as part of other revenues in the table above. This increase was due primarily to higher gas prices in the nine months ended June 30, 2008 as compared with the nine months ended June 30, 2007.

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The Pipeline and Storage segment's earnings for the quarter ended June 30, 2008 were $12.5 million, a decrease of $2.9 million when compared to earnings of $15.4 million for the quarter ended June 30, 2007. The decrease in earnings primarily reflects the earnings impact associated with higher operation and maintenance expenses resulting from the non-recurrence in 2008 of a reversal of a reserve for preliminary survey costs ($4.8 million) related to the Empire Connector project recognized in the quarter ended June 30, 2007. In addition, there was an earnings decrease associated with higher interest expense ($0.8 million). These earnings decreases were partially offset by an increase in the allowance for funds used during construction ($1.0 million), higher efficiency gas revenues ($1.2 million) and the earnings benefit associated with lower income taxes ($0.5 million).

The Pipeline and Storage segment's earnings for the nine months ended June 30, 2008 were $40.9 million, a decrease of $2.1 million when compared to earnings of $43.0 million for the nine months ended June 30, 2007. The main factors contributing to this decrease were higher operation and maintenance expenses ($5.7 million), resulting from the non-recurrence in 2008 of a reversal of a reserve for preliminary survey costs ($4.8 million) related to the Empire Connector project recognized during the quarter ended June 30, 2007. In addition, there was a $1.9 million positive earnings impact during the nine months ended June 30, 2007 associated with the discontinuance of hedge accounting for Empire's interest rate collar that did not recur during the nine months ended June 30, 2008. There was also an earnings decrease associated with higher interest expense ($1.1 million). These earnings decreases were partially offset by an increase in the allowance for funds used during construction ($2.3 million), higher efficiency gas revenues ($2.0 million), and higher transportation and storage revenues ($2.5 million).

Exploration and Production

Exploration and Production Operating Revenues

	Three Months Ended June 30,			Nine Months Ended June 30,		
(Thousands)	2008	2007	Increase/ (Decrease)	2008	2007	Increase/ (Decrease)
Gas (after Hedging) from Continuing Operations	$ 56,591	$34,712	$ 21,879	$155,793	$107,976	$ 47,817
Oil (after Hedging) from Continuing Operations	66,695	42,577	24,118	185,650	117,084	68,566
Gas Processing Plant from Continuing Operations	13,566	10,466	3,100	35,674	28,212	7,462
Other from Continuing Operations	(291)	(291)	—	(3,174)	165	(3,339)
Intrasegment Elimination from Continuing Operations (1)	(10,407)	(7,436)	(2,971)	(25,114)	(19,729)	(5,385)
Operating Revenues from Continuing Operations	$126,154	$80,028	$ 46,126	$348,829	$233,708	$115,121
Operating Revenues from Canada – Discontinued Operations	$ —	$14,366	$(14,366)	$ —	$ 42,004	$ (42,004)

(1) Represents the elimination of certain West Coast gas production revenue included in "Gas (after Hedging) from Continuing Operations" in the table above that was sold to the gas processing plant shown in the table above. An elimination for the same dollar amount was made to reduce the gas processing plant's Purchased Gas expense.

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Production Volumes

	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Increase/ (Decrease)	Nine Months Ended June 30, 2008	Nine Months Ended June 30, 2007	Increase/ (Decrease)
Gas Production *(MMcf)*						
Gulf Coast	3,019	2,317	702	8,868	7,934	934
West Coast	1,007	1,019	(12)	3,010	2,883	127
Appalachia	1,793	1,266	527	5,538	3,998	1,540
Total Production from Continuing Operations	5,819	4,602	1,217	17,416	14,815	2,601
Canada — Discontinued Operations	—	1,639	(1,639)	—	5,216	(5,216)
Total Production	5,819	6,241	(422)	17,416	20,031	(2,615)
Oil Production *(Mbbl)*						
Gulf Coast	124	165	(41)	409	540	(131)
West Coast	598	599	(1)	1,825	1,789	36
Appalachia	23	32	(9)	88	91	(3)
Total Production from Continuing Operations	745	796	(51)	2,322	2,420	(98)
Canada — Discontinued Operations	—	58	(58)	—	175	(175)
Total Production	745	854	(109)	2,322	2,595	(273)

Average Prices

	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Increase	Nine Months Ended June 30, 2008	Nine Months Ended June 30, 2007	Increase
Average Gas Price/Mcf						
Gulf Coast	$ 12.17	$ 7.37	$ 4.80	$ 9.66	$ 6.74	$ 2.92
West Coast	$ 10.61	$ 7.20	$ 3.41	$ 8.43	$ 6.76	$ 1.67
Appalachia	$ 11.53	$ 8.59	$ 2.94	$ 9.25	$ 7.71	$ 1.54
Weighted Average for Continuing Operations	$ 11.71	$ 7.67	$ 4.04	$ 9.32	$ 7.01	$ 2.31
Weighted Average After Hedging for Continuing Operations	$ 9.73	$ 7.54	$ 2.19	$ 8.95	$ 7.29	$ 1.66
Canada - Discontinued Operations	N/M	$ 6.82	N/M	N/M	$ 6.34	N/M
Average Oil Price/bbl						
Gulf Coast	$124.43	$65.17	$59.26	$103.46	$59.37	$44.09
West Coast	$114.35	$57.77	$56.58	$ 94.64	$52.96	$41.68
Appalachia	$114.99	$60.43	$54.56	$ 94.18	$59.35	$34.83
Weighted Average for Continuing Operations	$116.05	$59.41	$56.64	$ 96.17	$54.63	$41.54
Weighted Average After Hedging for Continuing Operations	$ 89.55	$53.54	$36.01	$ 79.97	$48.39	$31.58
Canada - Discontinued Operations	N/M	$51.58	N/M	N/M	$48.16	N/M

2008 Compared with 2007

Operating revenues from continuing operations for the Exploration and Production segment increased $46.1 million for the quarter ended June 30, 2008 as compared with the quarter ended June 30, 2007. Oil production revenue after hedging from continuing operations increased $24.1 million due to a

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$36.01 per barrel increase in weighted average prices after hedging for continuing operations. Gas production revenue after hedging from continuing operations increased $21.9 million due to an increase in the weighted average price of gas after hedging for continuing operations ($2.19 per Mcf) as well as an increase in gas production of 1,217 MMcf. The Gulf Coast region of this segment was primarily responsible for the increase in natural gas production from continuing operations (702 MMcf). Production from new fields in 2008 (primarily in the High Island area) outpaced declines in production from some existing fields, quarter to quarter. The Appalachian region of this segment also contributed to the increase in natural gas production from continuing operations (527 MMcf), consistent with increased drilling activity in the region.

Operating revenues from continuing operations for the Exploration and Production segment increased $115.1 million for the nine months ended June 30, 2008 as compared with the nine months ended June 30, 2007. Oil production revenue after hedging from continuing operations increased $68.6 million due primarily to a $31.58 per barrel increase in weighted average prices after hedging for continuing operations. Gas production revenue after hedging from continuing operations increased $47.8 million due to an increase in the weighted average price of gas after hedging for continuing operations ($1.66 per Mcf) and an increase in gas production of 2,601 MMcf. The increase in gas production from continuing operations occurred primarily in the Appalachian region (1,540 MMcf), consistent with increased drilling activity in the region. The Gulf Coast region also contributed to the increase in natural gas production from continuing operations (934 MMcf). Production from new fields in 2008 (primarily in the High Island area) outpaced declines in production from some existing fields, period to period, as discussed above.

The Exploration and Production segment's earnings from continuing operations for the quarter ended June 30, 2008 were $39.8 million, an increase of $21.0 million when compared with earnings from continuing operations of $18.8 million for the quarter ended June 30, 2007. Higher crude oil prices, higher natural gas prices and higher natural gas production increased earnings by $17.4 million, $8.3 million and $6.0 million, respectively, while lower crude oil production decreased earnings by $1.8 million. Higher lease operating costs ($4.2 million), higher depletion expense ($3.1 million), higher state income tax expense ($2.5 million) and higher general and administrative and other operating expenses ($1.5 million) also negatively impacted earnings. Lower interest expense of $2.1 million slightly offset these decreases.

The Exploration and Production segment's earnings from continuing operations for the nine months ended June 30, 2008 were $108.4 million, an increase of $55.8 million when compared with earnings from continuing operations of $52.6 million for the nine months ended June 30, 2007. Higher crude oil prices, higher natural gas prices and higher natural gas production increased earnings by $47.7 million, $18.8 million and $12.3 million, respectively, while lower crude oil production decreased earnings by $3.1 million. Higher lease operating costs ($9.0 million), higher depletion expense ($8.9 million), higher state income tax expense ($3.4 million), higher general and administrative and other operating expenses ($3.8 million), and mark-to-market adjustments on derivative financial instruments ($1.3 million) also negatively impacted earnings. Lower interest expense of $4.5 million and higher interest income of $1.6 million slightly offset these decreases.

Energy Marketing

Energy Marketing Operating Revenues

	Three Months Ended June 30,			Nine Months Ended June 30,		
(Thousands)	2008	2007	Increase/ (Decrease)	2008	2007	Increase/ (Decrease)
Natural Gas (after Hedging)	$162,127	$113,351	$ 48,776	$440,123	$359,895	$ 80,228
Other	2	29	(27)	(12)	141	(153)
	$162,129	$113,380	$ 48,749	$440,111	$360,036	$ 80,075

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Energy Marketing Volumes

	Three Months Ended June 30,			Nine Months Ended June 30,		
	2008	2007	Increase	2008	2007	Increase
Natural Gas — (MMcf)	14,641	13,014	1,627	47,189	44,063	3,126

2008 Compared with 2007

Operating revenues for the Energy Marketing segment increased $48.7 million and $80.1 million, respectively, for the quarter and nine months ended June 30, 2008 as compared with the quarter and nine months ended June 30, 2007. The increase for both the quarter and nine months ended June 30, 2008 is primarily due to higher gas sales revenue due to an increase in the price of natural gas that was recovered through revenues as well as an increase in volumes. The increase in volumes is attributable to an increase in volumes sold to low-margin wholesale customers, as well as an increase in the number of commercial and industrial customers served by the Energy Marketing segment.

Earnings in the Energy Marketing segment decreased $0.8 million and $1.4 million, respectively, for the quarter and nine months ended June 30, 2008 as compared with the quarter and nine months ended June 30, 2007. For the quarter ended June 30, 2008, higher operating costs of $0.8 million, primarily due to an increase in bad debt expense, are responsible for the decrease in earnings. Despite higher operating revenues and volumes, margins did not change significantly because the volume increase is primarily attributable to low-margin customers. For the nine months ended June 30, 2008, higher operating costs of $1.0 million (primarily due to an increase in bad debt expense) coupled with lower margins of $0.5 million are responsible for the decrease in earnings. A major factor in the margin decrease is the non-recurrence of a purchased gas expense adjustment recorded during the quarter ended March 31, 2007. During that quarter, the Energy Marketing segment reversed an accrual for $2.3 million of purchased gas expense due to the resolution of a contingency. The increase in volumes noted above, the profitable sale of certain gas held as inventory, and the marketing flexibility that the Energy Marketing segment derives from its contracts for significant storage capacity partially offset this decrease.

Timber

Timber Operating Revenues

	Three Months Ended June 30,			Nine Months Ended June 30,		
(Thousands)	2008	2007	Decrease	2008	2007	Increase/ (Decrease)
Log Sales	$ 2,726	$ 3,504	$ (778)	$16,649	$16,950	$ (301)
Green Lumber Sales	958	1,318	(360)	3,872	3,582	290
Kiln-Dried Lumber Sales	5,846	7,247	(1,401)	18,612	20,742	(2,130)
Other	584	1,062	(478)	1,305	1,805	(500)
Operating Revenues	$10,114	$13,131	$ (3,017)	$40,438	$43,079	$ (2,641)

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Timber Board Feet

	Three Months Ended June 30,			Nine Months Ended June 30,		
(Thousands)	2008	2007	Decrease	2008	2007	Increase/ (Decrease)
Log Sales	1,527	1,724	(197)	7,140	6,458	682
Green Lumber Sales	2,273	2,709	(436)	7,496	6,619	877
Kiln-Dried Lumber Sales	3,436	4,001	(565)	10,536	10,953	(417)
	7,236	8,434	(1,198)	25,172	24,030	1,142

2008 Compared with 2007

Operating revenues for the Timber segment decreased $3.0 million for the quarter ended June 30, 2008 as compared with the quarter ended June 30, 2007. The decrease can be primarily attributed to a decrease in both log sales and kiln-dried lumber sales of $0.8 million and $1.4 million, respectively. Overall, the Timber segment is currently selling a greater amount of lower priced, low margin species than higher margin species due to poor market conditions and wet weather that hampered harvesting, resulting in a decline in revenues. The decrease in log sales is due to a decline in cherry veneer log sales volumes of 106,000 board feet that can be attributed to the mix of logs being harvested in the current quarter as compared to the quarter ended June 30, 2007. Cherry veneer logs are more valuable and sell at higher prices than other species and have the largest impact on overall log sales revenue. The decrease in kiln-dried lumber sales is due to both a decline in sales volumes of 565,000 board feet as well as a decline in the market price of kiln-dried lumber.

Operating revenues for the Timber segment decreased $2.6 million for the nine months ended June 30, 2008 as compared with the nine months ended June 30, 2007. This decrease is largely due to a decline in kiln-dried lumber sales of $2.1 million. The decrease in kiln-dried lumber sales is due to both a decline in the market price of kiln-dried lumber as well as a decline in kiln-dried lumber sales volumes of 417,000 board feet. Log sales also decreased $0.3 million primarily due to a decline in cherry veneer log sales volumes of 130,000 board feet, partially offset by increases in log sales volumes from lower priced logs. Cherry veneer logs are more valuable and sell at higher prices than other species and have the largest impact on overall log sales revenue.

The Timber segment recorded a loss of $2.1 million for the quarter ended June 30, 2008, a decrease of $1.7 million when compared with a loss of $0.4 million for the quarter ended June 30, 2007. This decrease was the result of lower margins of $1.7 million, largely from lumber and log sales due to the decrease in revenues noted above.

The Timber segment's earnings for the nine months ended June 30, 2008 were $2.2 million, a decrease of $0.9 million when compared with earnings of $3.1 million for the nine months ended June 30, 2007. The decrease was primarily due to an increase in depletion and depreciation expense of $0.6 million due to harvesting more timber from Company owned land than the prior year combined with the addition of a lumber sorter for Highland's sawmill operations that was placed into service in October 2007. Lower margins of $0.1 million also contributed to the decrease in earnings. During the six months ended March 31, 2008, margins were up over the prior year, largely due to favorable weather conditions, resulting in an increase in the harvesting of higher margin species. The change in market and weather conditions in the quarter ended June 30, 2008, as discussed above, eliminated the margin improvements seen during the six months ended March 31, 2008.

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Corporate and All Other

2008 Compared with 2007

Corporate and All Other recorded earnings of $1.3 million for the quarter ended June 30, 2008 compared with earnings of $2.3 million for the quarter ended June 30, 2007. The positive earnings impacts of higher income from unconsolidated subsidiaries ($0.4 million) and lower income tax expense ($0.4 million) were more than offset by higher interest expense ($1.2 million) and higher operating costs ($0.8 million). The increase in operating costs can be attributed to the proxy contest with New Mountain Vantage GP, L.L.C.

For the nine months ended June 30, 2008, Corporate and All Other had earnings of $4.6 million compared with earnings of $5.9 million for the nine months ended June 30, 2007. The positive earnings impacts of higher income from unconsolidated subsidiaries ($1.1 million), lower income tax expense ($0.8 million), lower interest expense ($0.7 million), a gain on the sale of a turbine by Horizon Power ($0.6 million), and slightly higher margins by Horizon LFG ($0.3 million) were more than offset by higher operating costs ($4.5 million) and lower interest income ($0.6 million). The increase in operating costs can be attributed to the proxy contest with New Mountain Vantage GP, L.L.C.

Interest Income

Interest income was $1.7 million higher in the quarter ended June 30, 2008 as compared to the quarter ended June 30, 2007. For the nine months ended June 30, 2008, interest income increased $5.3 million as compared with the nine months ended June 30, 2007. These increases are mainly due to higher interest income (excluding intercompany interest income) in the Exploration and Production segment of $1.1 million and $4.0 million, respectively, for the quarter and nine months ended June 30, 2008 as compared to the quarter and nine months ended June 30, 2007 as a result of the investment of cash proceeds received from the sale of SECI in August 2007.

Interest Expense on Long-Term Debt

Interest on long-term debt increased $1.2 million for the quarter ended June 30, 2008 as compared with the quarter ended June 30, 2007. For the nine months ended June 30, 2008, interest on long-term debt decreased $0.1 million as compared with the nine months ended June 30, 2007. The increase in the quarter ended June 30, 2008 is due to the issuance in April 2008 of a $300 million, 6.5% Note due in April 2018. This increase was offset slightly by the repayment of $200 million of 6.303% medium-term notes that matured on May 27, 2008. The decrease in the nine months ended June 30, 2008 as compared to the nine months ended June 30, 2007 is due to an overall decline in interest on long-term debt as a result of a lower average amount of long-term debt outstanding. The Company repaid $22.8 million of Empire's secured debt in December 2006. It also redeemed $96.3 million of 6.5% unsecured notes in April 2007.

CAPITAL RESOURCES AND LIQUIDITY

The Company's primary sources of cash during the nine-month period ended June 30, 2008 consisted of cash provided by operating activities and proceeds from the issuance of long-term debt. These sources of cash were supplemented by issues of new shares of common stock as a result of stock option exercises. During the nine months ended June 30, 2008, the common stock used to fulfill the requirements of the Company's 401(k) plans and Direct Stock Purchase and Dividend Reinvestment Plan was obtained via open market purchases. During fiscal 2006, the Company began repurchasing outstanding shares of its common stock under a share repurchase program, which is discussed below under Financing Cash Flow.

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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations (Cont.)

Operating Cash Flow

Internally generated cash from operating activities consists of net income available for common stock, adjusted for non-cash expenses, non-cash income and changes in operating assets and liabilities. Non-cash items include depreciation, depletion and amortization, deferred income taxes, and income or loss from unconsolidated subsidiaries net of cash distributions.

Cash provided by operating activities in the Utility and the Pipeline and Storage segments may vary from period to period because of the impact of rate cases. In the Utility segment, over- or under-recovered purchased gas costs and weather may also significantly impact cash flow. The impact of weather on cash flow is tempered in the Utility segment's New York rate jurisdiction by its WNC and in the Pipeline and Storage segment by Supply Corporation's straight fixed-variable rate design.

Because of the seasonal nature of the heating business in the Utility and Energy Marketing segments, revenues in these segments are relatively high during the heating season, primarily the first and second quarters of the fiscal year, and receivable balances historically increase during these periods from the balances receivable at September 30.

The storage gas inventory normally declines during the first and second quarters of the fiscal year and is replenished during the third and fourth quarters. For storage gas inventory accounted for under the LIFO method, the current cost of replacing gas withdrawn from storage is recorded in the Consolidated Statements of Income and a reserve for gas replacement is recorded in the Consolidated Balance Sheets under the caption "Other Accruals and Current Liabilities." Such reserve is reduced as the inventory is replenished.

Cash provided by operating activities in the Exploration and Production segment may vary from period to period as a result of changes in the commodity prices of natural gas and crude oil. The Company uses various derivative financial instruments, including price swap agreements, no cost collars and futures contracts in an attempt to manage this energy commodity price risk.

Net cash provided by operating activities totaled $415.1 million for the nine months ended June 30, 2008, an increase of $10.5 million compared with $404.6 million provided by operating activities for the nine months ended June 30, 2007. The increase is partially due to lower working capital requirements in the Utility segment for the nine months ended June 30, 2008 as compared to the nine months ended June 30, 2007. In the Exploration and Production segment, for the nine months ended June 30, 2008 as compared to the nine months ended June 30, 2007, cash provided by operations increased due to higher commodity prices, partially offset by the decrease in cash provided by operations that resulted from the sale of SECI in August 2007. Offsetting these increases were higher working capital requirements in the Energy Marketing segment.

Investing Cash Flow

Expenditures for Long-Lived Assets

The Company's expenditures for long-lived assets totaled $284.6 million during the nine months ended June 30, 2008. The table below presents these expenditures:

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Nine Months Ended June 30, 2008 (*in millions of dollars*)

	Total Expenditures for Long-Lived Assets
Utility	$ 38.8
Pipeline and Storage (1)	106.2
Exploration and Production	140.6
Timber	1.2
Corporate and All Other	0.2
Eliminations (2)	(2.4)
	$ 284.6

(1) Amount includes $19.9 million of accrued capital expenditures related to the Empire Connector project. This amount has been excluded from the Consolidated Statement of Cash Flows at June 30, 2008 since it represents a non-cash investing activity at that date.

(2) Represents $2.4 million of capital expenditures included in the Appalachian region of the Exploration and Production segment for the purchase of storage facilities, buildings, and base gas from Supply Corporation during the quarter ended March 31, 2008.

Utility

The majority of the Utility capital expenditures for the nine months ended June 30, 2008 were made for replacement of mains and main extensions, as well as for the replacement of service lines.

Pipeline and Storage

The majority of the Pipeline and Storage capital expenditures for the nine months ended June 30, 2008 were related to the Empire Connector project costs, which is discussed below, as well as for additions, improvements, and replacements to this segment's transmission and gas storage systems.

The Company continues to explore various opportunities to expand its capabilities to transport gas to the East Coast, either through the Supply Corporation or Empire systems or in partnership with others. Construction of the Empire Connector, a pipeline designed to transport up to approximately 250 MDth of natural gas per day that will connect the Empire Pipeline with the Millennium Pipeline, began in September 2007. The Empire Connector is on schedule to be completed by the planned in-service date of November 2008, although the actual in-service date will depend upon the completion of the Millennium Pipeline. Refer to the Rate and Regulatory Matters section that follows for further discussion of this matter. The total cost to the Company of the Empire Connector project is estimated at $180 million, after giving effect to sales tax exemptions worth approximately $3.7 million. As of June 30, 2008, the Company had incurred approximately $107.7 million in costs related to this project. Of this amount, $42.7 million and $88.0 million were incurred during the quarter and nine months ended June 30, 2008, respectively, and $2.1 million and $3.5 million were incurred during the quarter and nine months ended June 30, 2007, respectively. All project costs incurred as of June 30, 2008 have been capitalized as Construction Work in Progress. The Company anticipates financing the remaining cost of this project with cash on hand.

Supply Corporation continues to view its potential Tuscarora Extension project as an important link to Millennium and potential storage development in the Corning, New York area. This new pipeline, which would expand the Supply Corporation system from its Tuscarora storage field to the intersection of the proposed Millennium and Empire Connector pipelines, could be designed initially to transport up to approximately 130 MDth of natural gas per day. It may also provide Supply Corporation with the opportunity to increase the deliverability of the existing Tuscarora storage field. Using the results of a preliminary Open Season, Supply Corporation is also exploring a new project (the West to East project) that would provide for new capacity from the Rockies Express Project, Appalachian production, storage and other points to Leidy and to interconnections with Millennium and Empire at Corning. The West to East project could include the Tuscarora Extension project, or could be a second phase following the development of the Tuscarora Extension project.

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In light of the rapidly growing demand for pipeline capacity to move natural gas from new wells being drilled in Appalachia, Supply Corporation recently initiated a new Open Season for its "Appalachian Lateral," a project designed to complement the West to East project. The Appalachian Lateral is expected to be located through an area where producers are actively drilling and seeking to find access to the market for their newly discovered reserves.

In conjunction with the West to East and Appalachian Lateral projects, Supply Corporation has plans to develop new storage capacity by pursuing expansion of certain of its existing storage facilities. The expansion of these fields, which Supply Corporation hopes to market through one offering at market-based rates, could provide approximately 8.5 Bcf of incremental storage capacity with incremental withdrawal deliverability of up to 121 MDth of natural gas per day, available in 2011. Supply Corporation expects that the availability of this incremental storage capacity will complement the West to East and Appalachian Lateral pipeline projects and help meet the demand for storage created by the prospective increased flow of Rockies and Appalachian gas supply into the western Pennsylvania area, although traditional gas supplies will also be able to take advantage of this incremental storage capacity. An Open Season for this storage capacity is planned to be held later in 2008.

The timeline associated with Supply Corporation's pipeline and storage projects depends on market development. Should the market materialize, the Company anticipates financing the Tuscarora Extension project and/or the storage expansion(s) with cash on hand and/or through the use of the Company's lines of credit. The capital cost of the West to East and Appalachian Lateral projects would amount to at least $700 million, which would be financed by a combination of debt and equity. As of June 30, 2008, there have been no costs incurred by Supply Corporation related to the Tuscarora Extension project, $0.1 million has been spent to study the West to East and Appalachian Lateral projects, and approximately $0.2 million has been spent to study the storage expansion project. Supply Corporation has not yet filed an application with the FERC for the authority to build either pipeline project or the storage expansion(s).

Exploration and Production

The Exploration and Production segment capital expenditures for the nine months ended June 30, 2008 included approximately $46.9 million for the Gulf Coast region, substantially all of which was for the off-shore program in the shallow waters of the Gulf of Mexico, $51.1 million for the West Coast region and $42.6 million for the Appalachian region. The Appalachian region capital expenditures include $2.4 million for the purchase of storage facilities, buildings, and base gas from Supply Corporation, as shown in the table on the previous page. These amounts included approximately $20.7 million spent to develop proved undeveloped reserves.

Timber

The majority of the Timber segment capital expenditures for the nine months ended June 30, 2008 were for construction of a lumber sorter for Highland's sawmill operations that was placed into service in October 2007 as well as for purchases of equipment for Highland's sawmill and kiln operations.

All Other

In March 2008, Horizon Power sold a gas-powered turbine that it had planned to use in the development of a co-generation plant. Horizon Power received proceeds of $5.3 million and recorded a pre-tax gain of $0.9 million associated with the sale.

The Company continuously evaluates capital expenditures and investments in corporations, partnerships, and other business entities. The amounts are subject to modification for opportunities such as the acquisition of attractive oil and gas properties, timber or natural gas storage facilities and the expansion of transmission line capacities. While the majority of capital expenditures in the Utility segment are necessitated by the continued need for replacement and upgrading of mains and service lines, the magnitude of future capital expenditures or other investments in the Company's other business segments depends, to a large degree, upon market conditions.

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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations (Cont.)

Financing Cash Flow

The Company did not have any outstanding short-term notes payable to banks or commercial paper at June 30, 2008. However, the Company continues to consider short-term debt (consisting of short-term notes payable to banks and commercial paper) an important source of cash for temporarily financing capital expenditures and investments in corporations and/or partnerships, gas-in-storage inventory, unrecovered purchased gas costs, margin calls on derivative financial instruments, exploration and development expenditures, repurchases of stock, and other working capital needs. Fluctuations in these items can have a significant impact on the amount and timing of short-term debt. As for bank loans, the Company maintains a number of individual uncommitted or discretionary lines of credit with certain financial institutions for general corporate purposes. Borrowings under these lines of credit are made at competitive market rates. These credit lines, which aggregate to $430.0 million, are revocable at the option of the financial institutions and are reviewed on an annual basis. The Company anticipates that these lines of credit will continue to be renewed, or replaced by similar lines. The total amount available to be issued under the Company's commercial paper program is $300.0 million. The commercial paper program is backed by a syndicated committed credit facility which totals $300.0 million and extends through September 30, 2010.

Under the Company's committed credit facility, the Company has agreed that its debt to capitalization ratio will not exceed .65 at the last day of any fiscal quarter through September 30, 2010. At June 30, 2008, the Company's debt to capitalization ratio (as calculated under the facility) was .41. The constraints specified in the committed credit facility would permit an additional $1.84 billion in short-term and/or long-term debt to be outstanding (further limited by the indenture covenants discussed below) before the Company's debt to capitalization ratio would exceed .65. If a downgrade in any of the Company's credit ratings were to occur, access to the commercial paper markets might not be possible. However, the Company expects that it could borrow under its uncommitted bank lines of credit or rely upon other liquidity sources, including cash provided by operations.

Under the Company's existing indenture covenants, at June 30, 2008, the Company would have been permitted to issue up to a maximum of $1.2 billion in additional long-term unsecured indebtedness at then-current market interest rates in addition to being able to issue new indebtedness to replace maturing debt. The Company's present liquidity position is believed to be adequate to satisfy known demands.

The Company's 1974 indenture pursuant to which $199.0 million (or 18%) of the Company's long-term debt (as of June 30, 2008) was issued contains a cross-default provision whereby the failure by the Company to perform certain obligations under other borrowing arrangements could trigger an obligation to repay the debt outstanding under the indenture. In particular, a repayment obligation could be triggered if the Company fails to (i) pay any scheduled principal or interest on any debt under any other indenture or agreement, or (ii) perform any other term in any other such indenture or agreement, and the effect of the failure causes, or would permit the holders of the debt to cause, the debt under such indenture or agreement to become due prior to its stated maturity, unless cured or waived.

The Company's $300.0 million committed credit facility also contains a cross-default provision whereby the failure by the Company or its significant subsidiaries to make payments under other borrowing arrangements, or the occurrence of certain events affecting those other borrowing arrangements, could trigger an obligation to repay any amounts outstanding under the committed credit facility. In particular, a repayment obligation could be triggered if (i) the Company or any of its significant subsidiaries fail to make a payment when due of any principal or interest on any other indebtedness aggregating $20.0 million or more, or (ii) an event occurs that causes, or would permit the holders of any other indebtedness aggregating $20.0 million or more to cause, such indebtedness to become due prior to its stated maturity. As of June 30, 2008, the Company had no debt outstanding under the committed credit facility.

In April 2008, the Company issued $300.0 million of 6.50% senior, unsecured notes in a private placement exempt from registration under the Securities Act of 1933. The notes have a term of 10 years, with a maturity date in April 2018. The holders of the notes may require the Company to repurchase their notes in the event of a change in control at a price equal to 101% of the principal amount. In addition, the

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Company is required to either offer to exchange the notes for substantially similar notes as are registered under the Securities Act of 1933 or, in certain circumstances, register the resale of the notes. The Company used $200.0 million of the proceeds to refund $200.0 million of 6.303% medium-term notes that subsequently matured on May 27, 2008.

On December 8, 2005, the Company's Board of Directors authorized the Company to implement a share repurchase program, whereby the Company may repurchase outstanding shares of common stock, up to an aggregate amount of 8 million shares in the open market or through privately negotiated transactions. As of June 30, 2008, the Company has repurchased 6,667,275 shares for $262.8 million under this program, including 439,722 and 2,832,397 shares for $20.7 million and $129.6 million, respectively, during the quarter and nine months ended June 30, 2008. These share repurchases were funded with cash provided by operating activities and/or through the use of the Company's lines of credit. In the future, it is expected that this share repurchase program will continue to be funded with cash provided by operating activities and/or through the use of the Company's lines of credit. It is anticipated that open market repurchases will continue from time to time depending on market conditions.

The Company may issue debt or equity securities in a public offering or a private placement from time to time. The amounts and timing of the issuance and sale of debt or equity securities will depend on market conditions, indenture requirements, regulatory authorizations and the capital requirements of the Company.

OFF-BALANCE SHEET ARRANGEMENTS

The Company has entered into certain off-balance sheet financing arrangements. These financing arrangements are primarily operating and capital leases. The Company's consolidated subsidiaries have operating leases, the majority of which are with the Utility and the Pipeline and Storage segments, having a remaining lease commitment of approximately $30.7 million. These leases have been entered into for the use of buildings, vehicles, construction tools, meters, computer equipment and other items and are accounted for as operating leases. The Company's unconsolidated subsidiaries, which are accounted for under the equity method, have capital leases of electric generating equipment having a remaining lease commitment of approximately $3.9 million. The Company has guaranteed 50% or $2.0 million of these capital lease commitments.

OTHER MATTERS

In addition to the legal proceedings disclosed in Part II, Item 1 of this report, the Company is involved in other litigation and regulatory matters arising in the normal course of business. These other matters may include, for example, negligence claims and tax, regulatory or other governmental audits, inspections, investigations or other proceedings. These matters may involve state and federal taxes, safety, compliance with regulations, rate base, cost of service and purchased gas cost issues, among other things. While these normal-course matters could have a material effect on earnings and cash flows in the quarterly and annual period in which they are resolved, they are not expected to change materially the Company's present liquidity position, nor are they expected to have a material adverse effect on the financial condition of the Company.

Market Risk Sensitive Instruments

For a complete discussion of market risk sensitive instruments, refer to "Market Risk Sensitive Instruments" in Item 7 of the Company's 2007 Form 10-K. There have been no subsequent material changes to the Company's exposure to market risk sensitive instruments.

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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations (Cont.)

Rate and Regulatory Matters

Utility Operation

Base rate adjustments in both the New York and Pennsylvania rate jurisdictions do not reflect the recovery of purchased gas costs. Such costs are recovered through operation of the purchased gas adjustment clauses of the appropriate regulatory authorities.

New York Jurisdiction

On January 29, 2007, Distribution Corporation commenced a rate case by filing proposed tariff amendments and supporting testimony requesting approval to increase its annual revenues by $52.0 million. Following standard procedure, the NYPSC suspended the proposed tariff amendments to enable its staff and intervenors to conduct a routine investigation and hold hearings. Distribution Corporation explained in the filing that its request for rate relief was necessitated by decreased revenues resulting from customer conservation efforts and increased customer uncollectibles, among other things. The rate filing also included a proposal for an efficiency and conservation initiative with a revenue decoupling mechanism designed to render the Company indifferent to throughput reductions resulting from conservation. On September 20, 2007, the NYPSC issued an order approving, with modifications, Distribution Corporation's conservation program for implementation on an accelerated basis. Associated ratemaking issues, however, were reserved for consideration in the rate case.

On December 21, 2007, the NYPSC issued a rate order providing for an annual rate increase of $1.8 million, together with a monthly bill surcharge that would collect up to $10.8 million to recover expenses for implementation of the conservation program. The rate increase and bill surcharge became effective December 28, 2007. The rate order further provided for a return on equity of 9.1%. The rate order also adopted Distribution Corporation's proposed revenue decoupling mechanism. The revenue decoupling mechanism, like others, "decouples" revenues from throughput by enabling the Company to collect from small volume customers its allowed margin on average weather normalized usage per customer. The effect of the revenue decoupling mechanism is to render the Company financially indifferent to throughput decreases resulting from conservation. The Company surcharges or credits any difference from the average weather normalized usage per customer account. The surcharge or credit is calculated to recover total margin for the most recent twelve-month period ending December 31, and applied to customer bills annually, beginning March 1st.

On April 18, 2008, Distribution Corporation filed an appeal with Supreme Court, Albany County, seeking review of the rate order. The appeal contends that portions of the rate order should be invalidated because they fail to meet the applicable legal standard for agency decisions. Among the issues challenged by the Company are the reasonableness of the NYPSC's disallowance of expense items, including health care costs, and the methodology used for calculating rate of return, which the appeal contends understated the Company's cost of equity. The Company cannot predict the outcome of the appeal at this time.

Pennsylvania Jurisdiction

On June 1, 2006, Distribution Corporation filed proposed tariff amendments with PaPUC to increase annual revenues by $25.9 million to cover increases in the cost of service to be effective July 30, 2006. The rate request was filed to address increased costs associated with Distribution Corporation's ongoing construction program as well as increases in operating costs, particularly uncollectible accounts. Following standard regulatory procedure, the PaPUC issued an order on July 20, 2006 instituting a rate proceeding and suspending the proposed tariff amendments until March 2, 2007. On October 2, 2006, the parties, including Distribution Corporation, Staff of the PaPUC and intervenors, executed an agreement (Settlement) proposing to settle all issues in the rate proceeding. The Settlement includes an increase in annual revenues of $14.3 million to non-gas revenues, an agreement not to file a rate case until January 28, 2008 at the earliest and an early implementation date. The Settlement was approved by the PaPUC at its meeting on November 30, 2006, and the new rates became effective January 1, 2007.

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On June 8, 2006, the NTSB issued safety recommendations to Distribution Corporation, the PaPUC and certain other parties as a result of an investigation of a natural gas explosion that occurred on Distribution Corporation's system in Dubois, Pennsylvania in August 2004. The explosion destroyed a residence, resulting in the death of two people who lived there, and damaged a number of other houses in the immediate vicinity. Without admitting liability, Distribution Corporation settled all significant third-party claims against it related to the explosion.

The NTSB's safety recommendations to Distribution Corporation involved revisions to its butt-fusion procedures for joining plastic pipe, and revisions to its procedures for qualifying personnel who perform plastic fusions. Although not required by law to do so, Distribution Corporation implemented those recommendations. In December 2006, the NTSB classified its recommendations as "closed" after determining that Distribution Corporation took acceptable action with respect to the recommendations.

The NTSB's recommendation to the PaPUC was to require an analysis of the integrity of butt-fusion joints in Distribution Corporation's system and replacement of those joints that are determined to have unacceptable characteristics. Distribution Corporation has worked cooperatively with the Staff of the PaPUC to permit the PaPUC to undertake the analysis recommended by the NTSB.

In late November 2007, Distribution Corporation reached a tentative settlement with the Law Bureau Prosecutory Staff of the PaPUC (the "Law Bureau") regarding the explosion and the PaPUC's subsequent investigation. The Law Bureau and Distribution Corporation jointly submitted the terms of the settlement to the PaPUC for approval. The PaPUC issued the Settlement Agreement for public comment with a comment period ending April 3, 2008. While no comments were filed, the Chairman of the PaPUC recommended that, pursuant to revised provisions of the Settlement Agreement, Distribution Corporation should, without admitting liability, make a $100,000 payment to an assistance fund for payment-troubled customers and make an additional $50,000 payment to fund safety-related activities. The PaPUC adopted the Chairman's recommendation unanimously at its public meeting held on May 1, 2008, and a tentative final order was issued on May 21, 2008. Distribution Corporation accepted the proposed Settlement Agreement. No other comments were filed, and by its terms the tentative order approving the Settlement Agreement became final on June 5, 2008 without further action by the PaPUC. On June 19, 2008, Distribution Corporation fulfilled the last condition for closing the proceeding by providing notice to the Secretary of the PaPUC that the $100,000 payment to the assistance fund had been made. Distribution Corporation is working with the Staff of the PaPUC to determine how the additional $50,000 in safety-related funding will be spent.

Pipeline and Storage

Supply Corporation currently does not have a rate case on file with the FERC. A rate settlement approved by the FERC on February 9, 2007 requires Supply Corporation to make a general rate filing to be effective December 1, 2011, and bars Supply Corporation from making a general rate filing before then, with some exceptions specified in the settlement.

Empire currently does not have a rate case on file with the NYPSC. Among the issues resolved in connection with Empire's FERC application to build the Empire Connector are the rates and terms of service that will become applicable to all of Empire's business, effective upon Empire constructing and placing its new facilities into service (currently expected for November 2008). At that time, Empire will become an interstate pipeline subject to FERC regulation. The order described in the following paragraph requires Empire to make a filing at the FERC within three years after the in-service date justifying Empire's existing recourse rates or proposing alternative rates.

On December 21, 2006, the FERC issued an order granting a Certificate of Public Convenience and Necessity authorizing the construction and operation of the Empire Connector and various other related pipeline projects by other unaffiliated companies. The Empire Certificate contains various environmental and other conditions. Empire accepted that Certificate and received additional environmental permits from the U.S. Army Corps of Engineers and state environmental agencies. Empire also received, from all six upstate New York counties in which it will build the Empire Connector

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project, final approval of sales tax exemptions and temporary partial property tax abatements. In June 2007, Empire signed a firm transportation service agreement with KeySpan Gas East Corporation, under which Empire is obligated to provide transportation service that will require construction of this project. Construction began in September 2007 and is on schedule to be completed by the planned in-service date of November 2008, although the actual in-service date will depend upon the completion of the Millennium Pipeline.

Environmental Matters

The Company is subject to various federal, state and local laws and regulations relating to the protection of the environment. The Company has established procedures for the ongoing evaluation of its operations to identify potential environmental exposures and comply with regulatory policies and procedures. It is the Company's policy to accrue estimated environmental clean-up costs (investigation and remediation) when such amounts can reasonably be estimated and it is probable that the Company will be required to incur such costs.

The Company received, in 1998 and again in October 1999, notice that the NYDEC believes the Company is responsible for contamination discovered at a former manufactured gas plant site located in New York for which the Company had not been named as a PRP. In February 2007, the NYDEC identified the Company as a PRP for the site and issued a proposed remedial action plan. The NYDEC estimated clean-up costs under its proposed remedy to be $8.9 million if implemented. Although the Company commented to the NYDEC that the proposed remedial action plan contained a number of material errors, omissions and procedural defects, the NYDEC, in a March 2007 Record of Decision, selected the remedy it had previously proposed. In July 2007, the Company appealed the NYDEC's Record of Decision to the New York State Supreme Court, Albany County. The Court dismissed the appeal in January 2008. The Company filed a notice of appeal in February 2008. In July 2008, the Company withdrew its appeal and agreed to the terms of an Order on Consent issued by the NYDEC. Pursuant to the order, the Company will remediate the site consistent with the remedy selected in the NYDEC's Record of Decision. The Company will also reimburse the NYDEC in the amount of approximately $1.5 million for costs incurred in connection with the site from 1998 through May 30, 2007. The Company acknowledged that additional charges related to the site will be billed to the Company at a later date, including costs incurred by the NYDEC after May 30, 2007 and any costs incurred by the New York Department of Health. The Company has not received any estimates of such additional costs. The Company has recorded an estimated minimum liability of $10.4 million associated with this site.

At June 30, 2008, the Company has estimated its remaining clean-up costs related to former manufactured gas plant sites and third party waste disposal sites (including the former manufactured gas plant site discussed above) will be in the range of $13.5 million to $17.2 million. The minimum estimated liability of $13.5 million has been recorded on the Consolidated Balance Sheet at June 30, 2008, including the $10.4 million discussed above. The Company expects to recover its environmental clean-up costs from a combination of rate recovery and deferred insurance proceeds that are currently recorded as a regulatory liability on the Consolidated Balance Sheet.

The Company is currently not aware of any material additional exposure to environmental liabilities. However, changes in environmental regulations or other factors could adversely impact the Company.

New Accounting Pronouncements

In September 2006, the FASB issued SFAS 157. SFAS 157 provides guidance for using fair value to measure assets and liabilities. The pronouncement serves to clarify the extent to which companies measure assets and liabilities at fair value, the information used to measure fair value, and the effect that fair-value measurements have on earnings. SFAS 157 is to be applied whenever another standard requires or allows assets or liabilities to be measured at fair value. In accordance with FASB Staff Position FAS No. 157-2, SFAS 157 is effective for financial assets and financial liabilities that are recognized or disclosed at fair value on a recurring basis as of the Company's first quarter of fiscal 2009. The same FASB Staff Position delays the effective date for nonfinancial assets and nonfinancial liabilities, except for

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items that are recognized or disclosed at fair value on a recurring basis, until the Company's first quarter of fiscal 2010. The Company is currently evaluating the impact that the adoption of SFAS 157 will have on its consolidated financial statements.

In September 2006, the FASB also issued SFAS 158, (an amendment of SFAS 87, SFAS 88, SFAS 106, and SFAS 132R). SFAS 158 requires that companies recognize a net liability or asset to report the underfunded or overfunded status of their defined benefit pension and other post-retirement benefit plans on their balance sheets, as well as recognize changes in the funded status of a defined benefit post-retirement plan in the year in which the changes occur through comprehensive income. The pronouncement also specifies that a plan's assets and obligations that determine its funded status be measured as of the end of the Company's fiscal year, with limited exceptions. In accordance with SFAS 158, the Company has recognized the funded status of its benefit plans and implemented the disclosure requirements of SFAS 158 at September 30, 2007. The requirement to measure the plan assets and benefit obligations as of the Company's fiscal year-end date will be adopted by the Company by the end of fiscal 2009. Currently, the Company measures its plan assets and benefit obligations using a June 30th measurement date.

In February 2007, the FASB issued SFAS 159. SFAS 159 permits entities to choose to measure many financial instruments and certain other items at fair value that are not otherwise required to be measured at fair value under GAAP. A company that elects the fair value option for an eligible item will be required to recognize in current earnings any changes in that item's fair value in reporting periods subsequent to the date of adoption. SFAS 159 is effective as of the Company's first quarter of fiscal 2009. The Company is currently evaluating the impact, if any, that the adoption of SFAS 159 will have on its consolidated financial statements.

In December 2007, the FASB issued SFAS 141R. SFAS 141R will significantly change the accounting for business combinations in a number of areas including the treatment of contingent consideration, contingencies, acquisition costs, in process research and development and restructuring costs. In addition, under SFAS 141R, changes in deferred tax asset valuation allowances and acquired income tax uncertainties in a business combination after the measurement period will impact income tax expense. SFAS 141R is effective as of the Company's first quarter of fiscal 2010.

In December 2007, the FASB issued SFAS 160. SFAS 160 will change the accounting and reporting for minority interests, which will be recharacterized as noncontrolling interests (NCI) and classified as a component of equity. This new consolidation method will significantly change the accounting for transactions with minority interest holders. SFAS 160 is effective as of the Company's first quarter of fiscal 2010. The Company currently does not have any NCI.

In March 2008, the FASB issued SFAS 161. SFAS 161 requires entities to provide enhanced disclosures related to an entity's derivative instruments and hedging activities in order to enable investors to better understand how derivative instruments and hedging activities impact an entity's financial reporting. The additional disclosures include how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for under SFAS 133 and its related interpretations, and how derivative instruments and related hedged items affect an entity's financial position, financial performance, and cash flows. SFAS 161 is effective as of the Company's second quarter of fiscal 2009. The Company is currently evaluating the impact that the adoption of SFAS 161 will have on its disclosures in its notes to its consolidated financial statements.

Safe Harbor for Forward-Looking Statements

The Company is including the following cautionary statement in this Form 10-Q to make applicable and take advantage of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 for any forward-looking statements made by, or on behalf of, the Company. Forward-looking statements include statements concerning plans, objectives, goals, projections, strategies, future events or performance, and underlying assumptions and other statements which are other than statements of historical facts. From time to time, the Company may publish or otherwise make available forward-looking statements of this nature. All such subsequent forward-looking statements, whether written or oral and

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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations (Cont.)

whether made by or on behalf of the Company, are also expressly qualified by these cautionary statements. Certain statements contained in this report, including, without limitation, statements regarding future prospects, plans, performance and capital structure, anticipated capital expenditures, completion of construction projects, projections for pension and other post-retirement benefit obligations, impacts of the adoption of new accounting rules, and possible outcomes of litigation or regulatory proceedings, as well as statements that are identified by the use of the words "anticipates," "estimates," "expects," "forecasts," "intends," "plans," "predicts," "projects," "believes," "seeks," "will," "may," and similar expressions, are "forward-looking" statements as defined in the Private Securities Litigation Reform Act of 1995 and accordingly involve risks and uncertainties which could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. The forward-looking statements contained herein are based on various assumptions, many of which are based, in turn, upon further assumptions. The Company's expectations, beliefs and projections are expressed in good faith and are believed by the Company to have a reasonable basis, including, without limitation, management's examination of historical operating trends, data contained in the Company's records and other data available from third parties, but there can be no assurance that management's expectations, beliefs or projections will result or be achieved or accomplished. In addition to other factors and matters discussed elsewhere herein, the following are important factors that, in the view of the Company, could cause actual results to differ materially from those discussed in the forward-looking statements:

1. Changes in economic conditions, including economic disruptions caused by terrorist activities, acts of war or major accidents, and downturns in economic activity including national or regional recessions;
2. Changes in demographic patterns and weather conditions, including the occurrence of severe weather such as hurricanes;
3. Changes in the availability and/or price of natural gas or oil and the effect of such changes on the accounting treatment of derivative financial instruments or the valuation of the Company's natural gas and oil reserves;
4. Uncertainty of oil and gas reserve estimates;
5. Ability to successfully identify, drill for and produce economically viable natural gas and oil reserves, including shortages, delays or unavailability of equipment and services required in drilling operations;
6. Significant changes from expectations in the Company's actual production levels for natural gas or oil;
7. Changes in the availability and/or price of derivative financial instruments;
8. Changes in the price differentials between various types of oil;
9. Inability to obtain new customers or retain existing ones;
10. Significant changes in competitive factors affecting the Company;
11. Changes in laws and regulations to which the Company is subject, including changes in tax, environmental, safety and employment laws and regulations;
12. Governmental/regulatory actions, initiatives and proceedings, including those involving acquisitions, financings, rate cases (which address, among other things, allowed rates of return, rate design and retained gas), affiliate relationships, industry structure, franchise renewal, and environmental/safety requirements;
13. Unanticipated impacts of restructuring initiatives in the natural gas and electric industries;
14. Significant changes from expectations in actual capital expenditures and operating expenses and unanticipated project delays or changes in project costs or plans;

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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations (Concl.)

15. The nature and projected profitability of pending and potential projects and other investments, and the ability to obtain necessary governmental approvals and permits;

16. Occurrences affecting the Company's ability to obtain funds from operations, from borrowings under our credit lines or other credit facilities or from issuances of other short-term notes or debt or equity securities to finance needed capital expenditures and other investments, including any downgrades in the Company's credit ratings;

17. Ability to successfully identify and finance acquisitions or other investments and ability to operate and integrate existing and any subsequently acquired business or properties;

18. Impairments under the SEC's full cost ceiling test for natural gas and oil reserves;

19. Changes in the market price of timber and the impact such changes might have on the types and quantity of timber harvested by the Company;

20. Significant changes in tax rates or policies or in rates of inflation or interest;

21. Significant changes in the Company's relationship with its employees or contractors and the potential adverse effects if labor disputes, grievances or shortages were to occur;

22. Changes in accounting principles or the application of such principles to the Company;

23. The cost and effects of legal and administrative claims against the Company;

24. Changes in actuarial assumptions and the return on assets with respect to the Company's retirement plan and post-retirement benefit plans;

25. Increasing health care costs and the resulting effect on health insurance premiums and on the obligation to provide post-retirement benefits; or

26. Increasing costs of insurance, changes in coverage and the ability to obtain insurance.

The Company disclaims any obligation to update any forward-looking statements to reflect events or circumstances after the date hereof.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Refer to the "Market Risk Sensitive Instruments" section in Item 2 — MD&A.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

The term "disclosure controls and procedures" is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act. These rules refer to the controls and other procedures of a company that are designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed is accumulated and communicated to the company's management, including its principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure. The Company's management, including the Chief Executive Officer and Principal Financial Officer, evaluated the effectiveness of the Company's disclosure controls and procedures as of the end of the period covered by this report. Based upon that evaluation, the Company's Chief Executive Officer and Principal Financial Officer concluded that the Company's disclosure controls and procedures were effective as of June 30, 2008.

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Item 4. Controls and Procedures (Concl.)

Changes in Internal Controls Over Financial Reporting

There were no changes in the Company's internal control over financial reporting that occurred during the quarter ended June 30, 2008 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Part II. Other Information

Item 1. Legal Proceedings

On June 8, 2006, the NTSB issued safety recommendations to Distribution Corporation, the PaPUC and certain others as a result of its investigation of a natural gas explosion that occurred on Distribution Corporation's system in Dubois, Pennsylvania in August 2004. For a discussion of this matter, refer to Part II, Item 7 — MD&A of this report under the heading "Other Matters — Rate and Regulatory Matters."

For a discussion of various environmental and other matters, refer to Part I, Item 1 at Note 4 — Commitments and Contingencies, and Part I, Item 2 — MD&A of this report under the heading "Other Matters — Environmental Matters."

In addition to the matters referenced above, the Company is involved in other litigation and regulatory matters arising in the normal course of business. These other matters may include, for example, negligence claims and tax, regulatory or other governmental audits, inspections, investigations or other proceedings. These matters may involve state and federal taxes, safety, compliance with regulations, rate base, cost of service, and purchased gas cost issues, among other things. While these normal-course matters could have a material effect on earnings and cash flows in the quarterly and annual period in which they are resolved, they are not expected to change materially the Company's present liquidity position, nor to have a material adverse effect on the financial condition of the Company.

Item 1A. Risk Factors

The risk factors in Item 1A of the Company's 2007 Form 10-K, as amended by Item 1A of the Company's Form 10-Q for the quarter ended March 31, 2008, have not materially changed other than as set forth below. The risk factor presented below supersedes the risk factor having the same caption in the 2007 Form 10-K and should otherwise be read in conjunction with all of the risk factors disclosed in the 2007 Form 10-K and the March 31, 2008 Form 10-Q.

National Fuel may be adversely affected by economic conditions.

Periods of slowed economic activity generally result in decreased energy consumption, particularly by industrial and large commercial companies. As a consequence, national or regional recessions or other downturns in economic activity could adversely affect National Fuel's revenues and cash flows or restrict its future growth. Economic conditions in National Fuel's utility service territories and energy marketing territories also impact its collections of accounts receivable. Customers of National Fuel's Utility and Energy Marketing segments may have particular trouble paying their bills during periods of declining economic activity and high commodity prices, potentially resulting in increased bad debt expense and reduced earnings.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

On April 1, 2008, the Company issued a total of 2,400 unregistered shares of Company common stock to the eight non-employee directors of the Company who receive compensation under the Company's Retainer Policy for Non-Employee Directors, 300 shares to each such director. All of these unregistered shares were issued as partial consideration for the directors' services during the quarter ended June 30, 2008. These transactions were exempt from registration by Section 4(2) of the Securities Act of 1933 as transactions not involving a public offering.

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Item 2. Unregistered Sales of Equity Securities and Use of Proceeds (Concl.)

Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased(a)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Share Repurchase Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under Share Repurchase Plans or Programs (b)
Apr. 1 - 30, 2008	446,666	$ 46.99	439,722	1,332,725
May 1 - 31, 2008	32,337	$ 57.99	—	1,332,725
June 1 - 30, 2008	9,686	$ 58.43	—	1,332,725
Total	488,689	$ 47.94	439,722	1,332,725

(a) Represents (i) shares of common stock of the Company purchased on the open market with Company "matching contributions" for the accounts of participants in the Company's 401(k) plans, and (ii) shares of common stock of the Company tendered to the Company by holders of stock options or shares of restricted stock for the payment of option exercise prices or applicable withholding taxes, and (iii) shares of common stock of the Company purchased on the open market pursuant to the Company's publicly announced share repurchase program. Shares purchased other than through a publicly announced share repurchase program totaled 6,944 in April 2008, 32,337 in May 2008 and 9,686 in June 2008 (a three month total of 48,967). Of those shares, 19,363 were purchased for the Company's 401(k) plans and 29,604 were purchased as a result of shares tendered to the Company by holders of stock options or shares of restricted stock.

(b) On December 8, 2005, the Company's Board of Directors authorized the repurchase of up to eight million shares of the Company's common stock. Repurchases may be made from time to time in the open market or through private transactions.

Item 6. Exhibits

(a) Exhibits

Exhibit Number	Description of Exhibit
3(ii)	By-Laws:
•	National Fuel Gas Company By-Laws as amended June 11, 2008 (incorporated herein by reference to Exhibit 3.1, Form 8-K dated June 16, 2008).
4	Instruments defining the rights of security holders:
4.1	Officer's Certificate establishing 6.50% Notes due 2018, dated April 11, 2008
•	Amended and Restated Rights Agreement, dated as of July 11, 2008, between National Fuel Gas Company and The Bank of New York, as rights agent (incorporated herein by reference to Exhibit 4.1, Form 8-K dated July 15, 2008).
10	Material contracts:
•	Director Services Agreement, dated as of June 1, 2008, between National Fuel Gas Company and Philip C. Ackerman (incorporated herein by reference to Exhibit 99, Form 8-K dated June 16, 2008).
12	Statements regarding Computation of Ratios:
	Ratio of Earnings to Fixed Charges for the Twelve Months Ended June 30, 2008 and the Fiscal Years Ended September 30, 2004 through 2007.

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Item 6. Exhibits (Concl.)

Exhibit Number	Description of Exhibit
31.1	Written statements of Chief Executive Officer pursuant to Rule 13a-14(a) or Rule 15d-14(a) under the Securities Exchange Act of 1934.
31.2	Written statements of Principal Financial Officer pursuant to Rule 13a-14(a) or Rule 15d-14(a) under the Securities Exchange Act of 1934.
32	Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99	National Fuel Gas Company Consolidated Statement of Income for the Twelve Months Ended June 30, 2008 and 2007.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

NATIONAL FUEL GAS COMPANY
(Registrant)

/s/ R. J. Tanski
R. J. Tanski
Treasurer and Principal Financial Officer

/s/ K. M. Camiolo
K. M. Camiolo
Controller and Principal Accounting Officer

Date: August 8, 2008

10-K 1 l28879ae10vk.htm NATIONAL FUEL GAS COMPANY 10-K

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Fiscal Year Ended September 30, 2007

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Transition Period from to

Commission File Number 1-3880

National Fuel Gas Company
(Exact name of registrant as specified in its charter)

New Jersey *(State or other jurisdiction of incorporation or organization)*	**13-1086010** *(I.R.S. Employer Identification No.)*
6363 Main Street **Williamsville, New York** *(Address of principal executive offices)*	**14221** *(Zip Code)*

(716) 857-7000
Registrant's telephone number, including area code

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, $1 Par Value, and Common Stock Purchase Rights	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes þ No o

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15 (d) of the Act. Yes o No þ

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months and (2) has been subject to such filing requirements for the past 90 days. Yes þ No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. þ

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act.

Large Accelerated Filer þ Accelerated Filer o Non-Accelerated Filer o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes o No þ

The aggregate market value of the voting stock held by nonaffiliates of the registrant amounted to $3,540,898,000 as of March 31, 2007.

Common Stock, $1 Par Value, outstanding as of October 31, 2007: 83,473,107 shares.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive Proxy Statement for its 2008 Annual Meeting of Stockholders are incorporated by reference into Part III of this report.

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Glossary of Terms

Frequently used abbreviations, acronyms, or terms used in this report:

National Fuel Gas Companies

Company The Registrant, the Registrant and its subsidiaries or the Registrant's subsidiaries as appropriate in the context of the disclosure

Data-Track Data-Track Account Services, Inc.

Distribution Corporation National Fuel Gas Distribution Corporation

Empire Empire State Pipeline

ESNE Energy Systems North East, LLC

Highland Highland Forest Resources, Inc.

Horizon Horizon Energy Development, Inc.

Horizon B.V. Horizon Energy Development B.V.

Horizon LFG Horizon LFG, Inc.

Horizon Power Horizon Power, Inc.

Leidy Hub Leidy Hub, Inc.

Model City Model City Energy, LLC

National Fuel National Fuel Gas Company

NFR National Fuel Resources, Inc.

Registrant National Fuel Gas Company

SECI Seneca Energy Canada Inc.

Seneca Seneca Resources Corporation

Seneca Energy Seneca Energy II, LLC

Supply Corporation National Fuel Gas Supply Corporation

Toro Toro Partners, LP

U.E. United Energy, a.s.

Regulatory Agencies

EPA United States Environmental Protection Agency

FASB Financial Accounting Standards Board

FERC Federal Energy Regulatory Commission

NTSB National Transportation Safety Board

NYDEC New York State Department of Environmental Conservation

NYPSC State of New York Public Service Commission

PaPUC Pennsylvania Public Utility Commission

SEC Securities and Exchange Commission

Other

APB 18 Accounting Principles Board Opinion No. 18, The Equity Method of Accounting for Investments in Common Stock

APB 20 Accounting Principles Board Opinion No. 20, Accounting Changes

APB 25 Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees

Bbl Barrel (of oil)

Bcf Billion cubic feet (of natural gas)

Bcfe (or Mcfe) — represents Bcf (or Mcf) Equivalent The total heat value (Btu) of natural gas and oil expressed as a volume of natural gas. National Fuel uses a conversion formula of 1 barrel of oil = 6 Mcf of natural gas.

Board foot A measure of lumber and/or timber equal to 12 inches in length by 12 inches in width by one inch in thickness.

Btu British thermal unit; the amount of heat needed to raise the temperature of one pound of water one degree Fahrenheit.

Capital expenditure Represents additions to property, plant, and equipment, or the amount of money a company spends to buy capital assets or upgrade its existing capital assets.

Cashout revenues A cash resolution of a gas imbalance whereby a customer pays Supply Corporation for gas the customer receives in excess of amounts delivered into Supply Corporation's system by the customer's shipper.

CTA Cumulative Foreign Currency Translation Adjustment

Degree day A measure of the coldness of the weather experienced, based on the extent to which the daily average temperature falls below a reference temperature, usually 65 degrees Fahrenheit.

Derivative A financial instrument or other contract, the terms of which include an underlying variable (a price, interest rate, index rate, exchange rate, or other variable) and a notional amount (number of units, barrels, cubic feet, etc.). The terms also permit for the instrument or contract to be settled net, and no initial net investment is required to enter into the financial instrument or contract. Examples include futures contracts, options, no cost collars and swaps.

Development costs Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas.

Development well A well drilled to a known producing formation in a previously discovered field.

Dth Decatherm; one Dth of natural gas has a heating value of 1,000,000 British thermal units, approximately equal to the heating value of 1 Mcf of natural gas.

Exchange Act Securities Exchange Act of 1934, as amended

Expenditures for long-lived assets Includes capital expenditures, stock acquisitions and/or investments in partnerships.

Exploitation Development of a field, including the location, drilling, completion and equipment of wells necessary to produce the commercially recoverable oil and gas in the field.

Exploration costs Costs incurred in identifying areas that may warrant examination, as well as costs incurred in examining specific areas, including drilling exploratory wells.

Exploratory well A well drilled in unproven or semi-proven territory for the purpose of ascertaining the presence underground of a commercial hydrocarbon deposit.

FIN FASB Interpretation Number

FIN 47 FASB Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations — an Interpretation of SFAS 143.

FIN 48 FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes — an Interpretation of SFAS 109.

Firm transportation and/or storage The transportation and/or storage service that a supplier of such service is obligated by contract to provide and for which the customer is obligated to pay whether or not the service is utilized.

GAAP Accounting principles generally accepted in the United States of America

Goodwill An intangible asset representing the difference between the fair value of a company and the price at which a company is purchased.

Grid The layout of the electrical transmission system or a synchronized transmission network.

Heavy oil A type of crude petroleum that usually is not economically recoverable in its natural state without being heated or diluted.

Hedging A method of minimizing the impact of price, interest rate, and/or foreign currency exchange rate changes, often times through the use of derivative financial instruments.

Hub Location where pipelines intersect enabling the trading, transportation, storage, exchange, lending and borrowing of natural gas.

Interruptible transportation and/or storage The transportation and/or storage service that, in accordance with contractual arrangements, can be interrupted by the supplier of such service, and for which the customer does not pay unless utilized.

LIBOR London Interbank Offered Rate

LIFO Last-in, first-out

Mbbl Thousand barrels (of oil)

Mcf Thousand cubic feet (of natural gas)

MD&A Management's Discussion and Analysis of Financial Condition and Results of Operations

MDth Thousand decatherms (of natural gas)

MMcf Million cubic feet (of natural gas)

MMcfe Million cubic feet equivalent

NYMEX New York Mercantile Exchange. An exchange which maintains a futures market for crude oil and natural gas.

Order 636 An order issued by FERC entitled "Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations."

Proved developed reserves Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Proved undeveloped reserves Reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required to make these reserves productive.

PRP Potentially responsible party

PUHCA 1935 Public Utility Holding Company Act of 1935

PUHCA 2005 Public Utility Holding Company Act of 2005

Reserves The unproduced but recoverable oil and/or gas in place in a formation which has been proven by production.

Restructuring Generally referring to partial "deregulation" of the utility industry by statutory or regulatory process. Restructuring of federally regulated natural gas pipelines resulted in the separation (or "unbundled") of gas commodity service from transportation service for wholesale and large- volume retail markets. State restructuring programs attempt to extend the same process to retail mass markets.

SAR Stock-settled stock appreciation right

SFAS Statement of Financial Accounting Standards

SFAS 5 Statement of Financial Accounting Standards No. 5, Accounting for Contingencies

SFAS 43 Statement of Financial Accounting Standards No. 43, Accounting for Compensated Absences

SFAS 69 Statement of Financial Accounting Standards No. 69, Disclosures about Oil and Gas Producing Activities

SFAS 71 Statement of Financial Accounting Standards No. 71, Accounting for the Effects of Certain Types of Regulation

SFAS 87 Statement of Financial Accounting Standards No. 87, Employers' Accounting for Pensions

SFAS 88 Statement of Financial Accounting Standards No. 88, Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits

SFAS 106 Statement of Financial Accounting Standards No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions.

SFAS 109 Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes

SFAS 112 Statement of Financial Accounting Standards No. 112, Employers' Accounting for Postemployment Benefits, an amendment of SFAS 5 and 43

SFAS 115 Statement of Financial Accounting Standards No. 115, Accounting for Certain Investments in Debt and Equity Securities

SFAS 123 Statement of Financial Accounting Standards No. 123, Accounting for Stock-Based Compensation

SFAS 123R Statement of Financial Accounting Standards No. 123R, Share-Based Payment

SFAS 132R Statement of Financial Accounting Standards No. 132R, Employers' Disclosures about Pensions and Other Postretirement Benefits

SFAS 133 Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities

SFAS 142 Statement of Financial Accounting Standards No. 142, Goodwill and Other Intangible Assets

SFAS 143 Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations

SFAS 157 Statement of Financial Accounting Standards No. 157, Fair Value Measurements

SFAS 158 Statement of Financial Accounting Standards No. 158, Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an Amendment of SFAS 87, 88, 106, and 132R

SFAS 159 Statement of Financial Accounting Standards No. 159, The Fair Value Option for Financial Assets and Financial Liabilities — Including an Amendment of SFAS 115

Spot gas purchases The purchase of natural gas on a short-term basis.

Stock acquisitions Investments in corporations.

Unbundled service A service that has been separated from other services, with rates charged that reflect only the cost of the separated service.

VEBA Voluntary Employees' Beneficiary Association

WNC Weather normalization clause; a clause in utility rates which adjusts customer rates to allow a utility to recover its normal operating costs calculated at normal temperatures. If temperatures during the measured period are warmer than normal, customer rates are adjusted upward in order to recover projected operating costs. If temperatures during the measured period are colder than normal, customer rates are adjusted downward so that only the projected operating costs will be recovered.

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For the Fiscal Year Ended September 30, 2007

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This Form 10-K contains "forward-looking statements" as defined by the Private Securities Litigation Reform Act of 1995. Forward-looking statements should be read with the cautionary statements included in this Form 10-K at Item 7, MD&A, under the heading "Safe Harbor for Forward-Looking Statements." Forward-looking statements are all statements other than statements of historical fact, including, without limitation, statements regarding future prospects, plans, performance and capital structure, anticipated capital expenditures, completion of construction projects, projections for pension and other post-retirement benefit obligations, impacts of the adoption of new accounting rules, and possible outcomes of litigation or regulatory proceedings, as well as statements that are identified by the use of the words "anticipates," "estimates," "expects," "forecasts," "intends," "plans," "predicts," "projects," "believes," "seeks," "will," and "may" and similar expressions.

PART I

Item 1 *Business*

The Company and its Subsidiaries

National Fuel Gas Company (the Registrant), incorporated in 1902, is a holding company organized under the laws of the State of New Jersey. Except as otherwise indicated below, the Registrant owns directly or indirectly all of the outstanding securities of its subsidiaries. Reference to "the Company" in this report means the Registrant, the Registrant and its subsidiaries or the Registrant's subsidiaries as appropriate in the context of the disclosure. Also, all references to a certain year in this report relate to the Company's fiscal year ended September 30 of that year unless otherwise noted.

The Company is a diversified energy company consisting of five reportable business segments.

1. The Utility segment operations are carried out by National Fuel Gas Distribution Corporation (Distribution Corporation), a New York corporation. Distribution Corporation sells natural gas or provides natural gas transportation services to approximately 725,000 customers through a local distribution system located in western New York and northwestern Pennsylvania. The principal metropolitan areas served by Distribution Corporation include Buffalo, Niagara Falls and Jamestown, New York and Erie and Sharon, Pennsylvania.

2. The Pipeline and Storage segment operations are carried out by National Fuel Gas Supply Corporation (Supply Corporation), a Pennsylvania corporation, and Empire State Pipeline (Empire), a New York joint venture between two wholly owned subsidiaries of the Company. Supply Corporation provides interstate natural gas transportation and storage services for affiliated and nonaffiliated companies through (i) an integrated gas pipeline system extending from southwestern Pennsylvania to the New York-Canadian border at the Niagara River and eastward to Ellisburg and Leidy, Pennsylvania, and (ii) 28 underground natural gas storage fields owned and operated by Supply Corporation as well as four other underground natural gas storage fields owned and operated jointly with various other interstate gas pipeline companies. Supply Corporation is in the process of shutting down one of its smallest storage fields, which accounts for less than one percent of its marketable storage capacity. Empire, an intrastate pipeline company acquired by the Company in February 2003, transports natural gas for Distribution Corporation and for other utilities, large industrial customers and power producers in New York State. Empire owns a 157-mile pipeline that extends from the United States/Canadian border at the Niagara River near Buffalo, New York to near Syracuse, New York. Empire is constructing the Empire Connector project, which consists of a compressor station and a 78-mile pipeline extension from near Rochester, New York to an interconnection near Corning, New York with the unaffiliated Millennium Pipeline, which is also under construction. The Millennium Pipeline is expected to serve the New York City area upon its completion. Upon completion of the Empire and Millennium construction projects, which is currently expected to occur in November 2008, the Company expects that Empire will become an interstate pipeline company and will merge into Empire Pipeline, Inc. as described below.

3. The Exploration and Production segment operations are carried out by Seneca Resources Corporation (Seneca), a Pennsylvania corporation. Seneca is engaged in the exploration for, and the development and purchase of, natural gas and oil reserves in California, in the Appalachian region of the United States, in Wyoming, and in the Gulf Coast region of Texas, Louisiana, and Alabama, including offshore areas in federal waters and some state waters.

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In 2007, Seneca sold its subsidiary, Seneca Energy Canada Inc. (SECI), which conducted Exploration and Production operations in the provinces of Alberta, Saskatchewan and British Columbia in Canada. At September 30, 2007, the Company had U.S. reserves of 47,586 Mbbl of oil and 205,389 MMcf of natural gas.

4. The Energy Marketing segment operations are carried out by National Fuel Resources, Inc. (NFR), a New York corporation, which markets natural gas to industrial, commercial, public authority and residential end-users in western and central New York and northwestern Pennsylvania, offering competitively priced energy and energy management services for its customers.

5. The Timber segment operations are carried out by Highland Forest Resources, Inc. (Highland), a New York corporation, and by a division of Seneca known as its Northeast Division. This segment markets timber from its New York and Pennsylvania land holdings, owns two sawmill operations in northwestern Pennsylvania and processes timber consisting primarily of high quality hardwoods. At September 30, 2007, the Company owned 103,700 acres of timber property and managed an additional 3,105 acres of timber rights.

Financial information about each of the Company's business segments can be found in Item 7, MD&A and also in Item 8 at Note J — Business Segment Information.

The Company's other direct wholly owned subsidiaries are not included in any of the five reportable business segments and consist of the following:

- Horizon Energy Development, Inc. (Horizon), a New York corporation formed to engage in foreign and domestic energy projects through investments as a sole or substantial owner in various business entities. These entities include Horizon's wholly owned subsidiary, Horizon Energy Holdings, Inc., a New York corporation, which owns 100% of Horizon Energy Development B.V. (Horizon B.V.). Horizon B.V. is a Dutch company that is in the process of winding up or selling certain power development projects in Europe;
- Horizon LFG, Inc. (Horizon LFG), a New York corporation engaged through subsidiaries in the purchase, sale and transportation of landfill gas in Ohio, Michigan, Kentucky, Missouri, Maryland and Indiana. Horizon LFG and one of its wholly owned subsidiaries own all of the partnership interests in Toro Partners, LP (Toro), a limited partnership which owns and operates short-distance landfill gas pipeline companies. The Company acquired Toro in June 2003;
- Leidy Hub, Inc. (Leidy Hub), a New York corporation formed to provide various natural gas hub services to customers in the eastern United States;
- Data-Track Account Services, Inc. (Data-Track), a New York corporation formed to provide collection services principally for the Company's subsidiaries;
- Horizon Power, Inc. (Horizon Power), a New York corporation which is an "exempt wholesale generator" under PUHCA 2005 and is developing or operating mid-range independent power production facilities and landfill gas electric generation facilities; and
- Empire Pipeline, Inc., a New York corporation formed in 2005 to be the surviving corporation of a planned future merger with Empire, which is expected to occur after construction of the Empire Connector project (described below under the heading "Rates and Regulation" and under Item 7, MD&A under the headings "Investing Cash Flow" and "Rate and Regulatory Matters").

No single customer, or group of customers under common control, accounted for more than 10% of the Company's consolidated revenues in 2007.

Rates and Regulation

The Registrant is a holding company as defined under PUHCA 2005. PUHCA 2005 repealed PUHCA 1935, to which the Company was formerly subject, and granted the FERC and state public utility commissions access to certain books and records of companies in holding company systems. Pursuant to the FERC's regulations under PUHCA 2005, the Company and its subsidiaries are exempt from the FERC's books and records regulations under PUHCA 2005.

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The Utility segment's rates, services and other matters are regulated by the NYPSC with respect to services provided within New York and by the PaPUC with respect to services provided within Pennsylvania. For additional discussion of the Utility segment's rates and regulation, see Item 7, MD&A under the heading "Rate and Regulatory Matters" and Item 8 at Note C-Regulatory Matters.

The Pipeline and Storage segment's rates, services and other matters are currently regulated by the FERC with respect to Supply Corporation and by the NYPSC with respect to Empire. The FERC has authorized Empire to construct and operate additional facilities (the Empire Connector project) and to become a FERC-regulated interstate pipeline company upon placement of those facilities into service, which is currently expected to occur in November 2008. For additional discussion of the Pipeline and Storage segment's rates and regulation, see Item 7, MD&A under the heading "Rate and Regulatory Matters" and Item 8 at Note C-Regulatory Matters. For further discussion of the Empire Connector project, refer to Item 7, MD&A under the headings "Investing Cash Flow" and "Rate and Regulatory Matters."

The discussion under Item 8 at Note C-Regulatory Matters includes a description of the regulatory assets and liabilities reflected on the Company's Consolidated Balance Sheets in accordance with applicable accounting standards. To the extent that the criteria set forth in such accounting standards are not met by the operations of the Utility segment or the Pipeline and Storage segment, as the case may be, the related regulatory assets and liabilities would be eliminated from the Company's Consolidated Balance Sheets and such accounting treatment would be discontinued.

In addition, the Company and its subsidiaries are subject to the same federal, state and local (including foreign) regulations on various subjects, including environmental matters, to which other companies doing similar business in the same locations are subject.

The Utility Segment

The Utility segment contributed approximately 25.2% of the Company's 2007 income from continuing operations and 15.1% of the Company's 2007 net income available for common stock.

Additional discussion of the Utility segment appears below in this Item 1 under the headings "Sources and Availability of Raw Materials," "Competition: The Utility Segment" and "Seasonality," in Item 7, MD&A and in Item 8, Financial Statements and Supplementary Data.

The Pipeline and Storage Segment

The Pipeline and Storage segment contributed approximately 28.0% of the Company's 2007 income from continuing operations and 16.7% of the Company's 2007 net income available for common stock.

Supply Corporation has service agreements for all of its firm storage capacity, which totals approximately 68,408 MDth. The Utility segment has contracted for 27,865 MDth or 40.7% of the total firm storage capacity, and the Energy Marketing segment accounts for another 3,888 MDth or 5.7% of the total firm storage capacity. Nonaffiliated customers have contracted for the remaining 36,655 MDth or 53.6% of the total firm storage capacity. A majority of Supply Corporation's storage and transportation services is performed under contracts that allow Supply Corporation or the shipper to terminate the contract upon six or twelve months' notice effective at the end of the contract term. The contracts also typically include "evergreen" language designed to allow the contracts to extend year-to-year at the end of the primary term. At the beginning of 2008, 66.9% of Supply Corporation's total firm storage capacity was committed under contracts that, subject to 2007 shipper or Supply Corporation notifications, could have been terminated effective in 2008. Supply Corporation received one termination notice in 2007, for a 1.5 Bcf storage contract. Termination of that contract will be effective March 31, 2008, and Supply Corporation expects to remarket that capacity for service commencing April 1, 2008, at maximum tariff rates. The strong demand for market-area storage enabled Supply Corporation to eliminate its remaining storage service rate discounts in 2007. Supply Corporation anticipates that, effective April 1, 2008, all of its storage services will be contracted at the maximum tariff rates.

Supply Corporation's firm transportation capacity is not a fixed quantity, due to the diverse weblike nature of its pipeline system, and is subject to change as the market identifies different transportation paths and receipt/delivery

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point combinations. Supply Corporation currently has firm transportation service agreements for approximately 2,001 MDth per day (contracted transportation capacity). The Utility segment accounts for approximately 1,093 MDth per day or 54.6% of contracted transportation capacity, and the Energy Marketing and Exploration and Production segments represent another 100 MDth per day or 5.0% of contracted transportation capacity. The remaining 808 MDth or 40.4% of contracted transportation capacity is subject to firm contracts with nonaffiliated customers.

At the beginning of 2008, 58.0% of Supply Corporation's contracted transportation capacity was committed under affiliate contracts that were scheduled to expire in 2008 or, subject to 2007 shipper or Supply Corporation notifications, could have been terminated effective in 2008. Based on contract expirations and termination notices received in 2007 for 2008 termination, and taking into account any known contract additions, contracted transportation capacity with affiliates is expected to decrease 2.5% in 2008. Similarly, 24.3% of contracted transportation capacity was committed under unaffiliated shipper contracts that were scheduled to expire in 2008 or, subject to 2007 shipper or Supply Corporation notifications, could have been terminated effective in 2008. Based on contract expirations and termination notices received in 2007 for 2008 termination, and taking into account any known contract additions, contracted transportation capacity with unaffiliated shippers is expected to increase 2.1% in 2008. Supply Corporation previously has been successful in marketing and obtaining executed contracts for available transportation capacity (at discounted rates when necessary), and expects this success to continue.

Empire has service agreements for the 2007-2008 winter period for all of its firm transportation capacity, which totals approximately 565 MDth per day. Empire provides service under both annual contracts (service 12 months per year; contract term one or more years) and seasonal contracts (service during winter or summer only; contract term one or more partial years). Approximately 90.8% of Empire's firm contracted capacity is under multi-year annual contracts that expire after 2008. Approximately 2.7% of Empire's firm contracted capacity is under multi-year seasonal contracts that expire after 2008. The remaining capacity, which represents 6.5% of Empire's firm contracted capacity, is under single season or annual contracts which will expire before the end of 2008. Empire expects that all of this expiring capacity will be re-contracted under seasonal and/or annual arrangements for future contracting periods. The Utility segment accounts for approximately 7.7% of Empire's firm contracted capacity, and the Energy Marketing segment accounts for approximately 2.0% of Empire's firm contracted capacity, with the remaining 90.3% of Empire's firm contracted transportation capacity subject to contracts with nonaffiliated customers.

Additional discussion of the Pipeline and Storage segment appears below under the headings "Sources and Availability of Raw Materials," "Competition: The Pipeline and Storage Segment" and "Seasonality," in Item 7, MD&A and in Item 8, Financial Statements and Supplementary Data.

The Exploration and Production Segment

The Exploration and Production segment contributed approximately 37.1% of the Company's 2007 income from continuing operations and 62.4% of the Company's 2007 net income available for common stock.

Additional discussion of the Exploration and Production segment appears below under the headings "Discontinued Operations," "Sources and Availability of Raw Materials" and "Competition: The Exploration and Production Segment," in Item 7, MD&A and in Item 8, Financial Statements and Supplementary Data.

The Energy Marketing Segment

The Energy Marketing segment contributed approximately 3.8% of the Company's 2007 income from continuing operations and 2.3% of the Company's 2007 net income available for common stock.

Additional discussion of the Energy Marketing segment appears below under the headings "Sources and Availability of Raw Materials," "Competition: The Energy Marketing Segment" and "Seasonality," in Item 7, MD&A and in Item 8, Financial Statements and Supplementary Data.

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The Timber Segment

The Timber segment contributed approximately 1.9% of the Company's 2007 income from continuing operations and 1.1% of the Company's 2007 net income available for common stock.

Additional discussion of the Timber segment appears below under the headings "Sources and Availability of Raw Materials," "Competition: The Timber Segment" and "Seasonality," in Item 7, MD&A and in Item 8, Financial Statements and Supplementary Data.

All Other Category and Corporate Operations

The All Other category and Corporate operations contributed approximately 4.0% of the Company's 2007 income from continuing operations and 2.4% of the Company's 2007 net income available for common stock.

Additional discussion of the All Other category and Corporate operations appears below in Item 7, MD&A and in Item 8, Financial Statements and Supplementary Data.

Discontinued Operations

In August 2007, Seneca sold all of the issued and outstanding shares of SECI. SECI's operations are presented in the Company's financial statements as discontinued operations.

In July 2005, Horizon B.V. sold its entire 85.16% interest in United Energy, a.s. (U.E.), a district heating and electric generation business in the Czech Republic. United Energy's operations are presented in the Company's financial statements as discontinued operations.

Additional discussion of the Company's discontinued operations appears in Item 7, MD&A and in Item 8, Financial Statements and Supplementary Data.

Sources and Availability of Raw Materials

Natural gas is the principal raw material for the Utility segment. In 2007, the Utility segment purchased 79.6 Bcf of gas for core market demand. Gas purchased from producers and suppliers in the southwestern United States and Canada under firm contracts (seasonal and longer) accounted for 85% of these purchases. Purchases of gas on the spot market (contracts for one month or less) accounted for 15% of the Utility segment's 2007 purchases. Purchases from Chevron Natural Gas (21%), ConocoPhillips Company (15%) and Total Gas & Power North America Inc. (14%) accounted for 50% of the Utility's 2007 gas purchases. No other producer or supplier provided the Utility segment with more than 10% of its gas requirements in 2007.

Supply Corporation transports and stores gas owned by its customers, whose gas originates in the southwestern, mid-continent and Appalachian regions of the United States as well as in Canada. Empire transports gas owned by its customers, whose gas originates in the southwestern and mid-continent regions of the United States as well as in Canada. Additional discussion of proposed pipeline projects appears below under "Competition: The Pipeline and Storage Segment" and in Item 7, MD&A.

The Exploration and Production segment seeks to discover and produce raw materials (natural gas, oil and hydrocarbon liquids) as further described in this report in Item 7, MD&A and Item 8 at Note J-Business Segment Information and Note O-Supplementary Information for Oil and Gas Producing Activities.

With respect to the Timber segment, Highland requires an adequate supply of timber to process in its sawmill and kiln operations. Forty-nine percent of the timber processed during 2007 in Highland's sawmill operations came from land owned by the Company's subsidiaries, and 51% came from outside sources. Timber cut for gas well drilling locations, access roads, and pipelines constituted an increasing portion of Highland's timber supply, both from land owned by the Company's subsidiaries and from outside sources. In addition, Highland purchased approximately 6.5 million board feet of green lumber to augment lumber supply for its kiln operations.

The Energy Marketing segment depends on an adequate supply of natural gas to deliver to its customers. In 2007, this segment purchased 53 Bcf of natural gas, of which 51 Bcf served core market demands. The remaining

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2 Bcf largely represents gas used in operations. The gas purchased by the Energy Marketing segment originates in either the Appalachian or mid-continent regions of the United States or in Canada.

Competition

Competition in the natural gas industry exists among providers of natural gas, as well as between natural gas and other sources of energy. The natural gas industry has gone through various stages of regulation. Apart from environmental and state utility commission regulation, the natural gas industry has experienced considerable deregulation. This has enhanced the competitive position of natural gas relative to other energy sources, such as fuel oil or electricity, since some of the historical regulatory impediments to adding customers and responding to market forces have been removed. In addition, management believes that the environmental advantages of natural gas have enhanced its competitive position relative to other fuels.

The electric industry has been moving toward a more competitive environment as a result of changes in federal law in 1992 and initiatives undertaken by the FERC and various states. It remains unclear what the impact of any further restructuring in response to legislation or other events may be.

The Company competes on the basis of price, service and reliability, product performance and other factors. Sources and providers of energy, other than those described under this "Competition" heading, do not compete with the Company to any significant extent.

Competition: The Utility Segment

The changes precipitated by the FERC's restructuring of the natural gas industry in Order No. 636, which was issued in 1992, continue to reshape the roles of the gas utility industry and the state regulatory commissions. In both New York and Pennsylvania, Distribution Corporation has retained substantial numbers of residential and small commercial customers as sales customers. However, for many years almost all the industrial and a substantial number of commercial customers have purchased their gas supplies from marketers and utilized Distribution Corporation's gas transportation services. Regulators in both New York and Pennsylvania have adopted retail competition programs for natural gas supply purchases by the remaining utility sales customers. To date, the Utility segment's traditional distribution function remains largely unchanged; however, in New York, the Utility segment has instituted a number of programs to accommodate more widespread customer choice. In Pennsylvania, the PaPUC issued a report in October 2005 that concluded "effective competition" does not exist in the retail natural gas supply market statewide. In 2006, the PaPUC reconvened a stakeholder group to explore ways to increase the participation of retail customers in choice programs. A decision by the PaPUC on retail competition matters remains pending.

Competition for large-volume customers continues with local producers or pipeline companies attempting to sell or transport gas directly to end-users located within the Utility segment's service territories without use of the utility's facilities (i.e., bypass). In addition, competition continues with fuel oil suppliers and may increase with electric utilities making retail energy sales.

The Utility segment competes in its most vulnerable markets (the large commercial and industrial markets) by offering unbundled, flexible services. The Utility segment continues to develop or promote new sources and uses of natural gas or new services, rates and contracts. The Utility segment also emphasizes and provides high quality service to its customers.

Competition: The Pipeline and Storage Segment

Supply Corporation competes for market growth in the natural gas market with other pipeline companies transporting gas in the northeast United States and with other companies providing gas storage services. Supply Corporation has some unique characteristics which enhance its competitive position. Its facilities are located adjacent to Canada and the northeastern United States and provide part of the link between gas-consuming regions of the eastern United States and gas-producing regions of Canada and the southwestern, southern and other continental regions of the United States. This location offers the opportunity for increased transportation and storage services in the future.

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Empire competes for market growth in the natural gas market with other pipeline companies transporting gas in the northeast United States and upstate New York in particular. Empire is well situated to provide transportation from Canadian sourced gas, and its facilities are readily expandable. These characteristics provide Empire the opportunity to compete for an increased share of the gas transportation markets. As noted above, Empire is constructing the Empire Connector project, which will expand its natural gas pipeline and enable Empire to serve new markets in New York and elsewhere in the Northeast. For further discussion of this project, refer to Item 7, MD&A under the headings "Investing Cash Flow" and "Rate and Regulatory Matters."

Competition: The Exploration and Production Segment

The Exploration and Production segment competes with other oil and natural gas producers and marketers with respect to sales of oil and natural gas. The Exploration and Production segment also competes, by competitive bidding and otherwise, with other oil and natural gas producers with respect to exploration and development prospects.

To compete in this environment, Seneca originates and acts as operator on certain of its prospects, seeks to minimize the risk of exploratory efforts through partnership-type arrangements, utilizes technology for both exploratory studies and drilling operations, and seeks market niches based on size, operating expertise and financial criteria.

Competition: The Energy Marketing Segment

The Energy Marketing segment competes with other marketers of natural gas and with other providers of energy management services. Competition in this area is well developed with regard to price and services from local, regional and, more recently, national marketers.

Competition: The Timber Segment

With respect to the Timber segment, Highland competes with other sawmill operations and with other suppliers of timber, logs and lumber. These competitors may be local, regional, national or international in scope. This competition, however, is primarily limited to those entities which either process or supply high quality hardwoods species such as cherry, oak and maple as veneer logs, saw logs, export logs or lumber ultimately used in the production of high-end furniture, cabinetry and flooring. The Timber segment sells its products in domestic and international markets.

Seasonality

Variations in weather conditions can materially affect the volume of gas delivered by the Utility segment, as virtually all of its residential and commercial customers use gas for space heating. The effect that this has on Utility segment margins in New York is mitigated by a WNC, which covers the eight-month period from October through May. Weather that is more than 2.2% warmer than normal results in a surcharge being added to customers' current bills, while weather that is more than 2.2% colder than normal results in a refund being credited to customers' current bills.

Volumes transported and stored by Supply Corporation may vary materially depending on weather, without materially affecting its revenues. Supply Corporation's allowed rates are based on a straight fixed-variable rate design which allows recovery of fixed costs in fixed monthly reservation charges. Variable charges based on volumes are designed to recover only the variable costs associated with actual transportation or storage of gas.

Volumes transported by Empire may vary materially depending on weather, which can have a moderate effect on its revenues. Empire's allowed rates currently are based on a modified fixed-variable rate design, which allows recovery of most fixed costs in fixed monthly reservation charges. Variable charges based on volumes are designed to recover variable costs associated with actual transportation of gas, to recover return on equity, and to recover income taxes. When Empire becomes a FERC-regulated interstate pipeline company (which is currently expected to occur in November 2008), Empire's allowed rates, like Supply Corporation's, will be based on a straight fixed-variable design. Under that rate design, weather-related variations in transportation volumes will not materially affect revenues.

Variations in weather conditions materially affect the volume of gas consumed by customers of the Energy Marketing segment. Volume variations have a corresponding impact on revenues within this segment.

The activities of the Timber segment vary on a seasonal basis and are subject to weather constraints. Traditionally, the timber harvesting season occurs when timber growth is dormant and runs from approximately September to March. The operations conducted in the summer months typically focus on pulpwood and on thinning lower-grade or lower value trees from timber stands to encourage the growth of higher-grade or higher value trees.

Capital Expenditures

A discussion of capital expenditures by business segment is included in Item 7, MD&A under the heading "Investing Cash Flow."

Environmental Matters

A discussion of material environmental matters involving the Company is included in Item 7, MD&A under the heading "Environmental Matters" and in Item 8, Note H — Commitments and Contingencies.

Miscellaneous

The Company and its wholly owned or majority-owned subsidiaries had a total of 1,952 full-time employees at September 30, 2007. Excluding the 23 employees the Company had in its Canadian operations at SECI, this is a decrease of approximately one percent from the 1,970 employees in the Company's U.S. operations at September 30, 2006.

Agreements covering employees in collective bargaining units in New York are scheduled to expire in February 2008. The Company has reached new agreements with the local leadership of those collective bargaining units, and the members of each collective bargaining unit have either approved their respective new agreement or are scheduled to vote on their respective new agreement in December 2007. The new agreements provide for an effective date of February 2008 and an expiration date of February 2013. Certain agreements covering employees in collective bargaining units in Pennsylvania are scheduled to expire in April 2009, and other agreements covering employees in collective bargaining units in Pennsylvania are scheduled to expire in May 2009.

The Utility segment has numerous municipal franchises under which it uses public roads and certain other rights-of-way and public property for the location of facilities. When necessary, the Utility segment renews such franchises.

The Company makes its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and any amendments to those reports, available free of charge on the Company's internet website, www.nationalfuelgas.com, as soon as reasonably practicable after they are electronically filed with or furnished to the SEC. The information available at the Company's internet website is not part of this Form 10-K or any other report filed with or furnished to the SEC.

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Executive Officers of the Company as of November 15, 2007 (except as otherwise noted)(1)

Name and Age (as of November 15, 2007)	Current Company Positions and Other Material Business Experience During Past Five Years
Philip C. Ackerman (63)	Chairman of the Board of Directors since January 2002; Chief Executive Officer since October 2001; and President of Horizon since September 1995. Mr. Ackerman has served as a Director of the Company since March 1994, and previously served as President of the Company from July 1999 through January 2006.
David F. Smith (54)	President of the Company since February 2006; Chief Operating Officer of the Company since February 2006; President of Supply Corporation since April 2005; President of Empire since April 2005. Mr. Smith previously served as Vice President of the Company from April 2005 through January 2006; President of Distribution Corporation from July 1999 to April 2005; and Senior Vice President of Supply Corporation from July 2000 to April 2005.
Ronald J. Tanski (55)	Treasurer and Principal Financial Officer of the Company since April 2004; President of Distribution Corporation since February 2006; Treasurer of Distribution Corporation since April 2004; Treasurer of Horizon since February 1997. Mr. Tanski previously served as Controller of the Company from February 2003 through March 2004; Senior Vice President of Distribution Corporation from July 2001 through January 2006; and Controller of Distribution Corporation from February 1997 through March 2004.
Matthew D. Cabell (49)	President of Seneca since December 2006. Prior to joining Seneca, Mr. Cabell served as Executive Vice President and General Manager of Marubeni Oil & Gas (USA) Inc., an exploration and production company, from June 2003 to December 2006. From January 2002 to June 2003, Mr. Cabell served as a consultant assisting oil companies in upstream acquisition and divestment transactions as well as Gulf of Mexico entry strategy, first as an independent consultant and then as Vice President of Randall & Dewey, Inc., a major oil and gas transaction advisory firm. Mr. Cabell's prior employers are not subsidiaries or affiliates of the Company.
Karen M. Camiolo (48)	Controller and Principal Accounting Officer of the Company since April 2004; Controller of Distribution Corporation and Supply Corporation since April 2004; and Chief Auditor of the Company from July 1994 through March 2004.
Anna Marie Cellino (54)	Secretary of the Company since October 1995; Secretary of Distribution Corporation since September 1999; Senior Vice President of Distribution Corporation since July 2001.
Paula M. Ciprich (47)	General Counsel of the Company since January 2005; Assistant Secretary of Distribution Corporation since February 1997.
Donna L. DeCarolis (48)	Vice President Business Development of the Company since October 2007. Ms. DeCarolis previously served as President of NFR from January 2005 to October 2007; Secretary of NFR from March 2002 to October 2007; and Vice President of NFR from May 2001 to January 2005.
John R. Pustulka (55)	Senior Vice President of Supply Corporation since July 2001.
James D. Ramsdell (52)	Senior Vice President of Distribution Corporation since July 2001.

(1) The executive officers serve at the pleasure of the Board of Directors. The information provided relates to the Company and its principal subsidiaries. Many of the executive officers also have served or currently serve as officers or directors of other subsidiaries of the Company.

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Item 1A ***Risk Factors***

As a holding company, National Fuel depends on its operating subsidiaries to meet its financial obligations.

National Fuel is a holding company with no significant assets other than the stock of its operating subsidiaries. In order to meet its financial needs, National Fuel relies exclusively on repayments of principal and interest on intercompany loans made by National Fuel to its operating subsidiaries and income from dividends and other cash flow from the subsidiaries. Such operating subsidiaries may not generate sufficient net income to pay upstream dividends or generate sufficient cash flow to make payments of principal or interest on such intercompany loans.

National Fuel is dependent on bank credit facilities and continued access to capital markets to successfully execute its operating strategies.

In addition to its longer term debt that is issued to the public under its indentures, National Fuel relies upon shorter term bank borrowings and commercial paper to finance a portion of its operations. National Fuel is dependent on these capital sources to provide capital to its subsidiaries to allow them to acquire, maintain and develop their properties. The availability and cost of these credit sources is cyclical and these capital sources may not remain available to National Fuel or National Fuel may not be able to obtain money at a reasonable cost in the future. National Fuel's ability to borrow under its credit facilities and commercial paper agreements depends on National Fuel's compliance with its obligations under the facilities and agreements. In addition, all of National Fuel's short-term bank loans are in the form of floating rate debt or debt that may have rates fixed for very short periods of time. At present, National Fuel has no active interest rate hedges in place to protect against interest rate fluctuations on short-term bank debt. In addition, the interest rates on National Fuel's short-term bank loans and the ability of National Fuel to issue commercial paper are affected by its debt credit ratings published by Standard & Poor's Ratings Service, Moody's Investors Service and Fitch Ratings Service. A ratings downgrade could increase the interest cost of this debt and decrease future availability of money from banks, commercial paper purchasers and other sources. National Fuel believes it is important to maintain investment grade credit ratings to conduct its business.

National Fuel's credit ratings may not reflect all the risks of an investment in its securities.

National Fuel's credit ratings are an independent assessment of its ability to pay its obligations. Consequently, real or anticipated changes in the Company's credit ratings will generally affect the market value of the specific debt instruments that are rated, as well as the market value of the Company's common stock. National Fuel's credit ratings, however, may not reflect the potential impact on the value of its common stock of risks related to structural, market or other factors discussed in this Form 10-K.

National Fuel's need to comply with comprehensive, complex, and sometimes unpredictable government regulations may increase its costs and limit its revenue growth, which may result in reduced earnings.

While National Fuel generally refers to its Utility segment and its Pipeline and Storage segment as its "regulated segments," there are many governmental regulations that have an impact on almost every aspect of National Fuel's businesses. Existing statutes and regulations may be revised or reinterpreted and new laws and regulations may be adopted or become applicable to the Company, which may affect its business in ways that the Company cannot predict.

In its Utility segment, the operations of Distribution Corporation are subject to the jurisdiction of the NYPSC and the PaPUC. The NYPSC and the PaPUC, among other things, approve the rates that Distribution Corporation may charge to its utility customers. Those approved rates also impact the returns that Distribution Corporation may earn on the assets that are dedicated to those operations. If Distribution Corporation is required in a rate proceeding to reduce the rates it charges its utility customers, or if Distribution Corporation is unable to obtain approval for rate increases from these regulators, particularly when necessary to cover increased costs (including costs that may be incurred in connection with governmental investigations or

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proceedings or mandated infrastructure inspection, maintenance or replacement programs), earnings may decrease.

In addition to their historical methods of utility regulation, both the PaPUC and NYPSC have sought to establish competitive markets in which customers may purchase supplies of gas from marketers, rather than from utility companies. In June 1999, the Governor of Pennsylvania signed into law the Natural Gas Choice and Competition Act. The Act revised the Public Utility Code relating to the restructuring of the natural gas industry, to permit consumer choice of natural gas suppliers. The early programs instituted to comply with the Act have not resulted in significant change, and many residential customers currently continue to purchase natural gas from the utility companies. In October 2005, the PaPUC concluded that "effective competition" does not exist in the retail natural gas supply market statewide. The PaPUC has reconvened a stakeholder group to explore ways to increase the participation of retail customers in choice programs. In New York, in August 2004, the NYPSC issued its Statement of Policy on Further Steps Toward Competition in Retail Energy Markets. This policy statement has a similar goal of encouraging customer choice of alternative natural gas providers. In 2005, the NYPSC stepped up its efforts to encourage customer choice at the retail residential level, and customer choice activities increased in Distribution Corporation's New York service territory. In April 2007, the NYPSC, noting that the retail energy marketplace in New York is established and continuing to expand, commenced a review to determine if existing programs initially designed to promote competition had outlived their usefulness and whether the cost of programs currently funded by utility rate payers should be shifted to market competitors. Increased retail choice activities, to the extent they occur, may increase Distribution Corporation's cost of doing business, put an additional portion of its business at regulatory risk, and create uncertainty for the future, all of which may make it more difficult to manage Distribution Corporation's business profitably.

In its Pipeline and Storage segment, National Fuel is subject to the jurisdiction of the FERC with respect to Supply Corporation, and to the jurisdiction of the NYPSC with respect to Empire. (The FERC has authorized Empire to construct and operate additional facilities (the Empire Connector project). When Empire completes construction and commences operations of the Empire Connector, Empire will at that time become a FERC-regulated pipeline company.) The FERC and the NYPSC, among other things, approve the rates that Supply Corporation and Empire, respectively, may charge to their natural gas transportation and/or storage customers. Those approved rates also impact the returns that Supply Corporation and Empire may earn on the assets that are dedicated to those operations. State commissions can also petition the FERC to investigate whether Supply Corporation's rates are still just and reasonable, and if not, to reduce those rates prospectively. If Supply Corporation or Empire is required in a rate proceeding to reduce the rates it charges its natural gas transportation and/or storage customers, or if Supply Corporation or Empire is unable to obtain approval for rate increases, particularly when necessary to cover increased costs, Supply Corporation's or Empire's earnings may decrease.

National Fuel's liquidity, and in certain circumstances, its earnings, could be adversely affected by the cost of purchasing natural gas during periods in which natural gas prices are rising significantly.

Tariff rate schedules in each of the Utility segment's service territories contain purchased gas adjustment clauses which permit Distribution Corporation to file with state regulators for rate adjustments to recover increases in the cost of purchased gas. Assuming those rate adjustments are granted, increases in the cost of purchased gas have no direct impact on profit margins. Nevertheless, increases in the cost of purchased gas affect cash flows and can therefore impact the amount or availability of National Fuel's capital resources. National Fuel has issued commercial paper and used short-term borrowings in the past to temporarily finance storage inventories and purchased gas costs, and although National Fuel expects to do so in the future, it may not be able to access the markets for such borrowings at attractive interest rates or at all. Distribution Corporation is required to file an accounting reconciliation with the regulators in each of the Utility segment's service territories regarding the costs of purchased gas. Due to the nature of the regulatory process, there is a risk of a disallowance of full recovery of these costs during any period in which there has been a substantial upward spike in these costs. Any material disallowance of purchased gas costs could have a material adverse effect on cash flow and earnings. In addition, even when Distribution Corporation is allowed full recovery of these purchased gas costs, during periods when natural gas prices are significantly higher than historical levels, customers may

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have trouble paying the resulting higher bills, and Distribution Corporation's bad debt expenses may increase and ultimately reduce earnings.

Uncertain economic conditions may affect National Fuel's ability to finance capital expenditures and to refinance maturing debt.

National Fuel's ability to finance capital expenditures and to refinance maturing debt will depend upon general economic conditions in the capital markets. The direction in which interest rates may move is uncertain. Declining interest rates have generally been believed to be favorable to utilities, while rising interest rates are generally believed to be unfavorable, because of the levels of debt that utilities may have outstanding. In addition, National Fuel's authorized rate of return in its regulated businesses is based upon certain assumptions regarding interest rates. If interest rates are lower than assumed rates, National Fuel's authorized rate of return could be reduced. If interest rates are higher than assumed rates, National Fuel's ability to earn its authorized rate of return may be adversely impacted.

Decreased oil and natural gas prices could adversely affect revenues, cash flows and profitability.

National Fuel's exploration and production operations are materially dependent on prices received for its oil and natural gas production. Both short-term and long-term price trends affect the economics of exploring for, developing, producing, gathering and processing oil and natural gas. Oil and natural gas prices can be volatile and can be affected by: weather conditions, including natural disasters; the supply and price of foreign oil and natural gas; the level of consumer product demand; national and worldwide economic conditions, including economic disruptions caused by terrorist activities, acts of war or major accidents; political conditions in foreign countries; the price and availability of alternative fuels; the proximity to, and availability of capacity on transportation facilities; regional levels of supply and demand; energy conservation measures; and government regulations, such as regulation of natural gas transportation, royalties, and price controls. National Fuel sells most of its oil and natural gas at current market prices rather than through fixed-price contracts, although as discussed below, National Fuel frequently hedges the price of a significant portion of its future production in the financial markets. The prices National Fuel receives depend upon factors beyond National Fuel's control, including the factors affecting price mentioned above. National Fuel believes that any prolonged reduction in oil and natural gas prices would restrict its ability to continue the level of exploration and production activity National Fuel otherwise would pursue, which could have a material adverse effect on its revenues, cash flows and results of operations.

National Fuel has significant transactions involving price hedging of its oil and natural gas production as well as its fixed price purchase and sale commitments.

In order to protect itself to some extent against unusual price volatility and to lock in fixed pricing on oil and natural gas production for certain periods of time, National Fuel periodically enters into commodity price derivatives contracts (hedging arrangements) with respect to a portion of its expected production. These contracts may at any time cover as much as approximately 80% of National Fuel's expected energy production during the upcoming 12-month period. These contracts reduce exposure to subsequent price drops but can also limit National Fuel's ability to benefit from increases in commodity prices. In addition, the Energy Marketing segment enters into certain hedging arrangements, primarily with respect to its fixed price purchase and sales commitments and its volumes of gas stored underground. National Fuel's Pipeline and Storage segment enters into hedging arrangements with respect to certain sales of efficiency gas, and the All Other category has hedging arrangements in place with respect to certain volumes of landfill gas committed for sale.

Under the applicable accounting rules, the Company's hedging arrangements are subject to quarterly effectiveness tests. Inherent within those effectiveness tests are assumptions concerning the long-term price differential between different types of crude oil, assumptions concerning the difference between published natural gas price indexes established by pipelines in which hedged natural gas production is delivered and the reference price established in the hedging arrangements, assumptions regarding the levels of production that will be achieved and, with regard to fixed price commitments, assumptions regarding the creditworthiness of certain customers and their forecasted consumption of natural gas. Depending on market conditions for natural

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gas and crude oil and the levels of production actually achieved, it is possible that certain of those assumptions may change in the future, and, depending on the magnitude of any such changes, it is possible that a portion of the Company's hedges may no longer be considered highly effective. In that case, gains or losses from the ineffective derivative financial instruments would be marked-to-market on the income statement without regard to an underlying physical transaction. Gains would occur to the extent that hedge prices exceed market prices, and losses would occur to the extent that market prices exceed hedge prices.

Use of energy commodity price hedges also exposes National Fuel to the risk of non-performance by a contract counterparty. These parties might not be able to perform their obligations under the hedge arrangements.

It is National Fuel's policy that the use of commodity derivatives contracts comply with various restrictions in effect in respective business segments. For example, in the Exploration and Production segment, commodity derivatives contracts must be confined to the price hedging of existing and forecast production, and in the Energy Marketing segment, commodity derivatives with respect to fixed price purchase and sales commitments must be matched against commitments reasonably certain to be fulfilled. Similar restrictions apply in the Pipeline and Storage segment and the All Other category. National Fuel maintains a system of internal controls to monitor compliance with its policy. However, unauthorized speculative trades, if they were to occur, could expose National Fuel to substantial losses to cover positions in its derivatives contracts. In addition, in the event the Company's actual production of oil and natural gas falls short of hedged forecast production, the Company may incur substantial losses to cover its hedges.

You should not place undue reliance on reserve information because such information represents estimates.

This Form 10-K contains estimates of National Fuel's proved oil and natural gas reserves and the future net cash flows from those reserves that were prepared by National Fuel's petroleum engineers and audited by independent petroleum engineers. Petroleum engineers consider many factors and make assumptions in estimating National Fuel's oil and natural gas reserves and future net cash flows. These factors include: historical production from the area compared with production from other producing areas; the assumed effect of governmental regulation; and assumptions concerning oil and natural gas prices, production and development costs, severance and excise taxes, and capital expenditures. Lower oil and natural gas prices generally cause estimates of proved reserves to be lower. Estimates of reserves and expected future cash flows prepared by different engineers, or by the same engineers at different times, may differ substantially. Ultimately, actual production, revenues and expenditures relating to National Fuel's reserves will vary from any estimates, and these variations may be material. Accordingly, the accuracy of National Fuel's reserve estimates is a function of the quality of available data and of engineering and geological interpretation and judgment.

If conditions remain constant, then National Fuel is reasonably certain that its reserve estimates represent economically recoverable oil and natural gas reserves and future net cash flows. If conditions change in the future, then subsequent reserve estimates may be revised accordingly. You should not assume that the present value of future net cash flows from National Fuel's proved reserves is the current market value of National Fuel's estimated oil and natural gas reserves. In accordance with SEC requirements, National Fuel bases the estimated discounted future net cash flows from its proved reserves on prices and costs as of the date of the estimate. Actual future prices and costs may differ materially from those used in the net present value estimate. Any significant price changes will have a material effect on the present value of National Fuel's reserves.

Petroleum engineering is a subjective process of estimating underground accumulations of natural gas and other hydrocarbons that cannot be measured in an exact manner. The process of estimating oil and natural gas reserves is complex. The process involves significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. Future economic and operating conditions are uncertain, and changes in those conditions could cause a revision to National Fuel's future reserve estimates. Estimates of economically recoverable oil and natural gas reserves and of future net cash flows depend upon a number of variable factors and assumptions, including historical production from the area compared with production from other comparable producing areas, and the assumed effects of regulations by

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governmental agencies. Because all reserve estimates are to some degree subjective, each of the following items may differ materially from those assumed in estimating reserves: the quantities of oil and natural gas that are ultimately recovered, the timing of the recovery of oil and natural gas reserves, the production and operating costs incurred, the amount and timing of future development and abandonment expenditures, and the price received for the production.

The amount and timing of actual future oil and natural gas production and the cost of drilling are difficult to predict and may vary significantly from reserves and production estimates, which may reduce National Fuel's earnings.

There are many risks in developing oil and natural gas, including numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves and in projecting future rates of production and timing of development expenditures. The future success of National Fuel's Exploration and Production segment depends on its ability to develop additional oil and natural gas reserves that are economically recoverable, and its failure to do so may reduce National Fuel's earnings. The total and timing of actual future production may vary significantly from reserves and production estimates. National Fuel's drilling of development wells can involve significant risks, including those related to timing, success rates, and cost overruns, and these risks can be affected by lease and rig availability, geology, and other factors. Drilling for oil and natural gas can be unprofitable, not only from dry wells, but from productive wells that do not produce sufficient revenues to return a profit. Also, title problems, weather conditions, governmental requirements, and shortages or delays in the delivery of equipment and services can delay drilling operations or result in their cancellation. The cost of drilling, completing, and operating wells is often uncertain, and new wells may not be productive or National Fuel may not recover all or any portion of its investment. Without continued successful exploitation or acquisition activities, National Fuel's reserves and revenues will decline as a result of its current reserves being depleted by production. National Fuel cannot assure you that it will be able to find or acquire additional reserves at acceptable costs.

Financial accounting requirements regarding exploration and production activities may affect National Fuel's profitability.

National Fuel accounts for its exploration and production activities under the full cost method of accounting. Each quarter, on a country-by-country basis, National Fuel must compare the level of its unamortized investment in oil and natural gas properties to the present value of the future net revenue projected to be recovered from those properties according to methods prescribed by the SEC. In determining present value, the Company uses quarter-end spot prices for oil and natural gas (as adjusted for hedging). If, at the end of any quarter, the amount of the unamortized investment exceeds the net present value of the projected future cash flows, such investment may be considered to be "impaired," and the full cost accounting rules require that the investment must be written down to the calculated net present value. Such an instance would require National Fuel to recognize an immediate expense in that quarter, and its earnings would be reduced. National Fuel's Exploration and Production segment last recorded an impairment charge under the full cost method of accounting in 2006. Because of the variability in National Fuel's investment in oil and natural gas properties and the volatile nature of commodity prices, National Fuel cannot predict when in the future it may again be affected by such an impairment calculation.

Environmental regulation significantly affects National Fuel's business.

National Fuel's business operations are subject to federal, state, and local laws and regulations relating to environmental protection. These laws and regulations concern the generation, storage, transportation, disposal or discharge of contaminants into the environment and the general protection of public health, natural resources, wildlife and the environment. Costs of compliance and liabilities could negatively affect National Fuel's results of operations, financial condition and cash flows. In addition, compliance with environmental laws and regulations could require unexpected capital expenditures at National Fuel's facilities. Because the costs of complying with environmental regulations are significant, additional regulation could negatively affect National Fuel's business. Although National Fuel cannot predict the impact of the interpretation or enforcement

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of EPA standards or other federal, state and local regulations, National Fuel's costs could increase if environmental laws and regulations become more strict.

The nature of National Fuel's operations presents inherent risks of loss that could adversely affect its results of operations, financial condition and cash flows.

National Fuel's operations in its various segments are subject to inherent hazards and risks such as: fires; natural disasters; explosions; geological formations with abnormal pressures; blowouts during well drilling; collapses of wellbore casing or other tubulars; pipeline ruptures; spills; and other hazards and risks that may cause personal injury, death, property damage, environmental damage or business interruption losses. Additionally, National Fuel's facilities, machinery, and equipment may be subject to sabotage. Any of these events could cause a loss of hydrocarbons, environmental pollution, claims for personal injury, death, property damage or business interruption, or governmental investigations, recommendations, claims, fines or penalties. As protection against operational hazards, National Fuel maintains insurance coverage against some, but not all, potential losses. In addition, many of the agreements that National Fuel executes with contractors provide for the division of responsibilities between the contractor and National Fuel, and National Fuel seeks to obtain an indemnification from the contractor for certain of these risks. National Fuel is not always able, however, to secure written agreements with its contractors that contain indemnification, and sometimes National Fuel is required to indemnify others.

Insurance or indemnification agreements when obtained may not adequately protect National Fuel against liability from all of the consequences of the hazards described above. The occurrence of an event not fully insured or indemnified against, the imposition of fines, penalties or mandated programs by governmental authorities, the failure of a contractor to meet its indemnification obligations, or the failure of an insurance company to pay valid claims could result in substantial losses to National Fuel. In addition, insurance may not be available, or if available may not be adequate, to cover any or all of these risks. It is also possible that insurance premiums or other costs may rise significantly in the future, so as to make such insurance prohibitively expensive.

Due to the significant cost of insurance coverage for named windstorms in the Gulf of Mexico, National Fuel determined that it was not economical to purchase insurance to fully cover its exposures related to such storms. It is possible that named windstorms in the Gulf of Mexico could have a material adverse effect on National Fuel's results of operations, financial condition and cash flows.

Hazards and risks faced by National Fuel, and insurance and indemnification obtained or provided by National Fuel, may subject National Fuel to litigation or administrative proceedings from time to time. Such litigation or proceedings could result in substantial monetary judgments, fines or penalties against National Fuel or be resolved on unfavorable terms, the result of which could have a material adverse effect on National Fuel's results of operations, financial condition and cash flows.

National Fuel may be adversely affected by economic conditions.

Periods of slowed economic activity generally result in decreased energy consumption, particularly by industrial and large commercial companies. As a consequence, national or regional recessions or other downturns in economic activity could adversely affect National Fuel's revenues and cash flows or restrict its future growth. Economic conditions in National Fuel's utility service territories also impact its collections of accounts receivable.

Item 1B ***Unresolved Staff Comments***

None

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Item 2 *Properties*

General Information on Facilities

The net investment of the Company in property, plant and equipment was $2.9 billion at September 30, 2007. Approximately 62% of this investment was in the Utility and Pipeline and Storage segments, which are primarily located in western and central New York and northwestern Pennsylvania. The Exploration and Production segment, which has the next largest investment in net property, plant and equipment (34%), is primarily located in California, in the Appalachian region of the United States, in Wyoming, and in the Gulf Coast region of Texas, Louisiana, and Alabama. The remaining net investment in property, plant and equipment consisted of the Timber segment (3%) which is located primarily in northwestern Pennsylvania, and All Other and Corporate operations (1%). During the past five years, the Company has made additions to property, plant and equipment in order to expand and improve transmission and distribution facilities for both retail and transportation customers. Net property, plant and equipment has increased $33.7 million, or 1.2%, since 2002. During 2007, the Company sold SECI, Seneca's wholly owned subsidiary that operated in Canada. The net property, plant and equipment of SECI at the date of sale was $107.7 million. In addition, during 2005, the Company sold its majority interest in U.E., a district heating and electric generation business in the Czech Republic. The net property, plant and equipment of U.E. at the date of sale was $223.9 million.

The Utility segment had a net investment in property, plant and equipment of $1.1 billion at September 30, 2007. The net investment in its gas distribution network (including 14,813 miles of distribution pipeline) and its service connections to customers represent approximately 53% and 33%, respectively, of the Utility segment's net investment in property, plant and equipment at September 30, 2007.

The Pipeline and Storage segment had a net investment of $681.9 million in property, plant and equipment at September 30, 2007. Transmission pipeline represents 33% of this segment's total net investment and includes 2,495 miles of pipeline required to move large volumes of gas throughout its service area. Storage facilities represent 24% of this segment's total net investment and consist of 32 storage fields, four of which are jointly owned and operated with certain pipeline suppliers, and 441 miles of pipeline. Net investment in storage facilities includes $89.8 million of gas stored underground-noncurrent, representing the cost of the gas required to maintain pressure levels for normal operating purposes as well as gas maintained for system balancing and other purposes, including that needed for no-notice transportation service. The Pipeline and Storage segment has 28 compressor stations with 75,404 installed compressor horsepower that represent 14% of this segment's total net investment in property, plant and equipment.

The Exploration and Production segment had a net investment in property, plant and equipment of $982.7 million at September 30, 2007.

The Timber segment had a net investment in property, plant and equipment of $89.9 million at September 30, 2007. Located primarily in northwestern Pennsylvania, the net investment includes two sawmills, 103,700 acres of land and timber, and 3,105 acres of timber rights.

The Utility and Pipeline and Storage segments' facilities provided the capacity to meet the Company's 2007 peak day sendout, including transportation service, of 1,743 MMcf, which occurred on February 5, 2007. Withdrawals from storage of 779.3 MMcf provided approximately 44.7% of the requirements on that day.

Company maps are included in exhibit 99.2 of this Form 10-K and are incorporated herein by reference.

Exploration and Production Activities

The Company is engaged in the exploration for, and the development and purchase of, natural gas and oil reserves in California, in the Appalachian region of the United States, in Wyoming, and in the Gulf Coast region of Texas, Louisiana, and Alabama. Also, Exploration and Production operations were conducted in the provinces of Alberta, Saskatchewan and British Columbia in Canada, until the sale of these properties on August 31, 2007. Further discussion of the sale of the Canadian oil and gas properties is included in Item 8, Note-I-Discontinued Operations. Further discussion of oil and gas producing activities is included in Item 8, Note O-Supplementary Information for Oil and Gas Producing Activities. Note O sets forth proved developed

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and undeveloped reserve information for Seneca. Seneca's proved developed and undeveloped natural gas reserves decreased from 233 Bcf at September 30, 2006 to 205 Bcf at September 30, 2007. This decrease is attributed primarily to the sale of the Canadian gas properties (40.1 Bcf) and production of 26.3 Bcf. These decreases were partially offset by extensions and discoveries of 34.6 Bcf, primarily in the Appalachian region (29.7 Bcf). Seneca's proved developed and undeveloped oil reserves decreased from 58,018 Mbbl at September 30, 2006 to 47,586 Mbbl at September 30, 2007. This decrease is attributed to revisions of previous estimates (5,963 Mbbl), primarily occurring in California, production (3,450 Mbbl) and the sale of the Canadian oil properties (1,458 Mbbl). Seneca's proved developed and undeveloped natural gas reserves decreased from 238 Bcf at September 30, 2005 to 233 Bcf at September 30, 2006. This decrease is attributed primarily to production and downward reserve revisions related primarily to the Canadian properties. These decreases were partially offset by extensions and discoveries. The downward reserve revisions were largely a function of a significant decrease in gas prices during the fourth quarter of 2006. Seneca's proved developed and undeveloped oil reserves decreased from 60,257 Mbbl at September 30, 2005 to 58,018 Mbbl at September 30, 2006. This decrease is attributed mostly to production.

Seneca's oil and gas reserves reported in Item 8 at Note O as of September 30, 2007 were estimated by Seneca's geologists and engineers and were audited by independent petroleum engineers from Netherland, Sewell & Associates, Inc. Seneca reports its oil and gas reserve information on an annual basis to the Energy Information Administration (EIA), a statistical agency of the U.S. Department of Energy. The oil and gas reserve information reported to the EIA showed 211 Bcf and 59,246 Mbbl of gas and oil reserves, respectively, which differs from the reserve information summarized in Item 8 at Note O. The reasons for this difference are as follows: (a) reserves are reported to the EIA on a calendar year basis, while reserves disclosed in Item 8 at Note O are shown on a fiscal year basis; (b) reserves reported to the EIA include only properties operated by Seneca, while reserves disclosed in Item 8 at Note O included both Seneca operated properties and non-operated properties in which Seneca has an interest; and (c) reserves are reported to the EIA on a gross basis verses the reserves disclosed in Item 8 at Note O, which are reported on a net revenue interest basis.

The following is a summary of certain oil and gas information taken from Seneca's records. All monetary amounts are expressed in U.S. dollars.

Production

	For The Year Ended September 30		
	2007	2006	2005
United States			
Gulf Coast Region			
Average Sales Price per Mcf of Gas	$ 6.58	$ 8.01	$ 7.05
Average Sales Price per Barrel of Oil	$ 63.04	$ 64.10	$ 49.78
Average Sales Price per Mcf of Gas (after hedging)	$ 6.87	$ 5.89	$ 6.01
Average Sales Price per Barrel of Oil (after hedging)	$ 64.09	$ 47.46	$ 35.03
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$ 1.08	$ 0.86	$ 0.71
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	40	36	50
West Coast Region			
Average Sales Price per Mcf of Gas	$ 6.54	$ 7.93	$ 6.85
Average Sales Price per Barrel of Oil	$ 56.86	$ 56.80	$ 42.91
Average Sales Price per Mcf of Gas (after hedging)	$ 6.82	$ 7.19	$ 6.15
Average Sales Price per Barrel of Oil (after hedging)	$ 47.43	$ 37.69	$ 23.01
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$ 1.54	$ 1.35	$ 1.15

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	For The Year Ended September 30		
	2007	2006	2005
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	50	53	53
Appalachian Region			
Average Sales Price per Mcf of Gas	$ 7.48	$ 9.53	$ 7.60
Average Sales Price per Barrel of Oil	$ 62.26	$ 65.28	$ 48.28
Average Sales Price per Mcf of Gas (after hedging)	$ 8.25	$ 8.90	$ 7.01
Average Sales Price per Barrel of Oil (after hedging)	$ 62.26	$ 65.28	$ 48.28
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$ 0.69	$ 0.69	$ 0.63
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	17	15	13
Total United States			
Average Sales Price per Mcf of Gas	$ 6.82	$ 8.42	$ 7.13
Average Sales Price per Barrel of Oil	$ 58.43	$ 58.47	$ 44.87
Average Sales Price per Mcf of Gas (after hedging)	$ 7.25	$ 7.02	$ 6.26
Average Sales Price per Barrel of Oil (after hedging)	$ 51.68	$ 40.26	$ 26.59
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$ 1.23	$ 1.09	$ 0.90
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	108	104	117
Canada — Discontinued Operations			
Average Sales Price per Mcf of Gas	$ 6.09	$ 7.14	$ 6.15
Average Sales Price per Barrel of Oil	$ 50.06	$ 51.40	$ 42.97
Average Sales Price per Mcf of Gas (after hedging)	$ 6.17	$ 7.47	$ 6.14
Average Sales Price per Barrel of Oil (after hedging)	$ 50.06	$ 51.40	$ 42.97
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$ 1.94	$ 1.57	$ 1.29
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	21	26	27
Total Company			
Average Sales Price per Mcf of Gas	$ 6.64	$ 8.04	$ 6.86
Average Sales Price per Barrel of Oil	$ 57.93	$ 57.94	$ 44.72
Average Sales Price per Mcf of Gas (after hedging)	$ 6.98	$ 7.15	$ 6.23
Average Sales Price per Barrel of Oil (after hedging)	$ 51.58	$ 41.10	$ 27.86
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$ 1.35	$ 1.18	$ 0.98
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	129	130	144

Productive Wells

	Gulf Coast Region		West Coast Region		Appalachian Region		Total Company	
At September 30, 2007	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil
Productive Wells — Gross	33	37	—	1,313	2,347	7	2,380	1,357
Productive Wells — Net	19	16	—	1,305	2,274	6	2,293	1,327

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Developed and Undeveloped Acreage

At September 30, 2007	Golf Coast Region	West Coast Region	Appalachian Region	Total Company
Developed Acreage				
— Gross	141,425	11,058	515,400	667,883
— Net	97,756	10,688	488,907	597,351
Undeveloped Acreage				
— Gross	148,960	—	472,407	621,367
— Net	89,921	—	447,802	537,723

As of September 30, 2007, the aggregate amount of gross undeveloped acreage expiring in the next three years and thereafter are as follows: 23,332 acres in 2008 (12,707 net acres), 38,741 acres in 2009 (23,219 net acres), 23,038 acres in 2010 (11,491 net acres), and 536,256 acres thereafter (490,306 net acres).

Drilling Activity

	Productive			Dry		
For the Year Ended September 30	2007	2006	2005	2007	2006	2005
United States						
Gulf Coast Region						
Net Wells Completed						
— Exploratory	1.31	2.94	1.30	1.42	0.85	0.47
— Development	1.00	0.78	0.23	0.67	—	—
West Coast Region						
Net Wells Completed						
— Exploratory	0.50	—	—	—	—	—
— Development	58.99	92.98	116.97	2.00	1.00	—
Appalachian Region						
Net Wells Completed						
— Exploratory	8.10	3.88	3.00	—	—	4.00
— Development	184.00	140.58	45.00	2.00	1.75	1.00
Total United States						
Net Wells Completed						
— Exploratory	9.91	6.82	4.30	1.42	0.85	4.47
— Development	243.99	234.34	162.20	4.67	2.75	1.00
Canada — Discontinued Operations						
Net Wells Completed						
— Exploratory	6.38	12.60	21.14	—	1.35	2.00
— Development	1.80	2.50	3.50	—	1.00	—
Total						
Net Wells Completed						
— Exploratory	16.29	19.42	25.44	1.42	2.20	6.47
— Development	245.79	236.84	165.70	4.67	3.75	1.00

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Present Activities

At September 30, 2007	Gulf Coast Region	West Coast Region	Appalachian Region	Total Company
Wells in Process of Drilling(1)				
— Gross	2.00	4.00	90.00	96.00
— Net	1.30	4.00	88.00	93.30

(1) Includes wells awaiting completion.

Item 3 ***Legal Proceedings***

In an action instituted in the New York State Supreme Court, Kings County on February 18, 2003 against Distribution Corporation and Paul J. Hissin, an unaffiliated third party, plaintiff Donna Fordham-Coleman, as administratrix of the estate of Velma Arlene Fordham, alleges that Distribution Corporation's failure to initiate natural gas service, despite an attempt to do so, at an apartment leased to the plaintiff's decedent, Velma Arlene Fordham, caused the decedent's death in February 2001. The plaintiff sought damages for wrongful death and pain and suffering, plus punitive damages. Distribution Corporation denied plaintiff's material allegations, asserted seven affirmative defenses and asserted a cross-claim against the co-defendant. Distribution Corporation believes, and has vigorously asserted, that plaintiff's allegations lack merit. The court changed venue of the action to New York State Supreme Court, Erie County. Trial was scheduled to begin October 15, 2007. However, the parties resolved the action.

On June 8, 2006, the NTSB issued safety recommendations to Distribution Corporation, the PaPUC and certain others as a result of its investigation of a natural gas explosion that occurred on Distribution Corporation's system in Dubois, Pennsylvania in August 2004. For a discussion of this matter, refer to Part II, Item 7 — MD&A of this report under the heading "Other Matters — Rate and Regulatory Matters."

On November 8, 2007, Distribution Corporation filed a complaint with the PaPUC requesting that the PaPUC commence an investigation to determine whether New Mountain Vantage GP, L.L.C. (New Mountain), and others acting in concert with it, have violated Pennsylvania law by acquiring control of Distribution Corporation without the prior approval of the PaPUC. In the event the PaPUC finds that New Mountain and others acting in concert with it have not yet acquired control of Distribution Corporation, Distribution Corporation petitioned the PaPUC for an order requiring New Mountain to show cause why it should not be required to apply for and receive a certificate of public convenience prior to acquiring control of Distribution Corporation, and requiring that the certificate of public convenience be obtained prior to any vote of stockholders of the Company which could result in the acquisition of control over Distribution Corporation. According to a November 6, 2007 filing with the SEC, New Mountain and certain other holders acknowledging acting with New Mountain as part of a group for purposes of the federal securities laws collectively own 9.7% of the outstanding shares of the Company. Distribution Corporation alleges in its filing with the PaPUC that New Mountain and others acting in concert with it have acquired or are seeking to acquire control of the Company, which results or would result in the acquisition of indirect control over Distribution Corporation. On November 21, 2007, New Mountain filed preliminary objections to Distribution Corporation's complaint and petition and requested that the PaPUC rule on the preliminary objections at its December 20, 2007 public meeting. In addition, two agencies of the Commonwealth of Pennsylvania, the Office of Consumer Advocate and the Office of Small Business Advocate, petitioned the PaPUC to intervene in the proceeding, and the Office of Small Business Advocate requested evidentiary hearings. Distribution Corporation anticipates that its response to New Mountain's preliminary objections will request that the PaPUC, at its December 20, 2007 public meeting, initiate an investigation by issuing an order for New Mountain to show cause why it should not be required to apply for and receive a certificate of public convenience prior to acquiring control of Distribution Corporation.

The resolution of the Fordham-Coleman action described above will not have a material effect on the consolidated financial condition, results of operations, or cash flow of the Company. The Company believes, based on the information presently known, that the ultimate resolution of the matters before the PaPUC

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described above will not be material to the consolidated financial condition, results of operations, or cash flow of the Company. No assurances can be given, however, as to the ultimate outcomes of those matters, and it is possible that the outcomes could be material to the consolidated financial condition, results of operations or cash flow of the Company.

For a discussion of various environmental and other matters, refer to Part II, Item 7, MD&A and Item 8 at Note H — Commitments and Contingencies.

In addition to the matters disclosed above, the Company is involved in other litigation and regulatory matters arising in the normal course of business. These other matters may include, for example, negligence claims and tax, regulatory or other governmental audits, inspections, investigations or other proceedings. These matters may involve state and federal taxes, safety, compliance with regulations, rate base, cost of service, and purchased gas cost issues, among other things. While these normal-course matters could have a material effect on earnings and cash flows in the quarterly and annual period in which they are resolved, they are not expected to change materially the Company's present liquidity position, nor to have a material adverse effect on the financial condition of the Company.

Item 4 *Submission of Matters to a Vote of Security Holders*

No matter was submitted to a vote of security holders during the quarter ended September 30, 2007.

PART II

Item 5 *Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities*

Information regarding the market for the Company's common equity and related stockholder matters appears under Item 12 at Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters, Item 8 at Note E-Capitalization and Short-Term Borrowings and Note N-Market for Common Stock and Related Shareholder Matters (unaudited).

On July 2, 2007, the Company issued a total of 2,400 unregistered shares of Company common stock to the eight non-employee directors of the Company serving on the Board of Directors, 300 shares to each such director. All of these unregistered shares were issued as partial consideration for such directors' services during the quarter ended September 30, 2007, pursuant to the Company's Retainer Policy for Non-Employee Directors. These transactions were exempt from registration under Section 4(2) of the Securities Act of 1933, as transactions not involving a public offering.

Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased(a)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Share Repurchase Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under Share Repurchase Plans or Programs(b)
July 1-31, 2007	7,317	$ 44.75	—	4,278,122
Aug. 1-31, 2007	124,254	$ 41.93	113,000	4,165,122
Sept. 1-30, 2007	22,622	$ 44.97	—	4,165,122
Total	154,193	$ 42.51	113,000	4,165,122

(a) Represents (i) shares of common stock of the Company purchased on the open market with Company "matching contributions" for the accounts of participants in the Company's 401(k) plans, (ii) shares of common stock of the Company tendered to the Company by holders of stock options or shares of restricted stock for the payment of option exercise prices or applicable withholding taxes, and (iii) shares of common

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stock of the Company purchased on the open market pursuant to the Company's publicly announced share repurchase program. Shares purchased other than through a publicly announced share repurchase program totaled 7,317 in July 2007, 11,254 in August 2007 and 22,622 in September 2007 (a three-month total of 41,193). Of those shares, 23,498 were purchased for the Company's 401(k) plans and 17,695 were purchased as a result of shares tendered to the Company by holders of stock options or shares of restricted stock.

(b) On December 8, 2005, the Company's Board of Directors authorized the repurchase of up to eight million shares of the Company's common stock. Repurchases may be made from time to time in the open market or through private transactions.

Item 6 ***Selected Financial Data(1)***

	Year Ended September 30				
	2007	2006	2005	2004	2003
			(Thousands)		
Summary of Operations					
Operating Revenues	$ 2,039,566	$ 2,239,675	$ 1,860,774	$ 1,867,875	$ 1,821,899
Operating Expenses:					
Purchased Gas	1,018,081	1,267,562	959,827	949,452	963,567
Operation and Maintenance	396,408	395,289	388,094	374,010	330,316
Property, Franchise and Other Taxes	70,660	69,202	68,164	68,378	72,073
Depreciation, Depletion and Amortization	157,919	151,999	156,502	159,184	154,634
	1,643,068	1,884,052	1,572,587	1,551,024	1,520,590
Gain (Loss) on Sale of Timber Properties	—	—	—	(1,252)	168,787
Operating Income	396,498	355,623	288,187	315,599	470,096
Other Income (Expense):					
Income from Unconsolidated Subsidiaries	4,979	3,583	3,362	805	535
Impairment of Investment in Partnership	—	—	(4,158)	—	—
Interest Income	1,550	9,409	6,236	1,771	2,427
Other Income	4,936	2,825	12,744	2,908	2,204
Interest Expense on Long-Term Debt	(68,446)	(72,629)	(73,244)	(82,989)	(91,381)
Other Interest Expense	(6,029)	(5,952)	(9,069)	(6,354)	(11,010)
Income from Continuing Operations Before Income Taxes	333,488	292,859	224,058	231,740	372,871
Income Tax Expense	131,813	108,245	85,621	89,820	116,795
Income from Continuing Operations	201,675	184,614	138,437	141,920	256,076
Discontinued Operations:					
Income (Loss) from Operations, Net of Tax	15,479	(46,523)	25,277	24,666	(68,240)
Gain on Disposal, Net of Tax	120,301	—	25,774	—	—
Income (Loss) from Discontinued Operations, Net of Tax	135,780	(46,523)	51,051	24,666	(68,240)

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	Year Ended September 30				
	2007	2006	2005 (Thousands)	2004	2003
Income Before Cumulative Effect of Changes in Accounting	337,455	138,091	189,488	166,586	187,836
Cumulative Effect of Changes in Accounting	—	—	—	—	(8,892)
Net Income Available for Common Stock	$ 337,455	$ 138,091	$ 189,488	$ 166,586	$ 178,944
Per Common Share Data					
Basic Earnings from Continuing Operations per Common Share	$ 2.43	$ 2.20	$ 1.66	$ 1.73	$ 3.17
Diluted Earnings from Continuing Operations per Common Share	$ 2.37	$ 2.15	$ 1.63	$ 1.71	$ 3.15
Basic Earnings per Common Share(2)	$ 4.06	$ 1.64	$ 2.27	$ 2.03	$ 2.21
Diluted Earnings per Common Share(2)	$ 3.96	$ 1.61	$ 2.23	$ 2.01	$ 2.20
Dividends Declared	$ 1.22	$ 1.18	$ 1.14	$ 1.10	$ 1.06
Dividends Paid	$ 1.21	$ 1.17	$ 1.13	$ 1.09	$ 1.05
Dividend Rate at Year-End	$ 1.24	$ 1.20	$ 1.16	$ 1.12	$ 1.08
At September 30:					
Number of Registered Shareholders	16,989	17,767	18,369	19,063	19,217
Net Property, Plant and Equipment					
Utility	$ 1,099,280	$ 1,084,080	$ 1,064,588	$ 1,048,428	$ 1,028,393
Pipeline and Storage	681,940	674,175	680,574	696,487	705,927
Exploration and Production(3)	982,698	1,002,265	974,806	923,730	925,833
Energy Marketing	102	59	97	80	171
Timber	89,902	90,939	94,826	82,838	87,600
All Other	16,735	17,394	18,098	21,172	22,042
Corporate(4)	7,748	8,814	6,311	234,029	221,082
Total Net Plant	$ 2,878,405	$ 2,877,726	$ 2,839,300	$ 3,006,764	$ 2,991,048
Total Assets	$ 3,888,412	$ 3,763,748	$ 3,749,753	$ 3,738,103	$ 3,740,944
Capitalization					
Comprehensive Shareholders' Equity	$ 1,630,119	$ 1,443,562	$ 1,229,583	$ 1,253,701	$ 1,137,390
Long-Term Debt, Net of Current Portion	799,000	1,095,675	1,119,012	1,133,317	1,147,779
Total Capitalization	$ 2,429,119	$ 2,539,237	$ 2,348,595	$ 2,387,018	$ 2,285,169

(1) Certain prior year amounts have been reclassified to conform with current year presentation.

(2) Includes discontinued operations and cumulative effect of changes in accounting.

(3) Includes net plant of SECI discontinued operations as follows: $0 for 2007, $88,023 for 2006, $170,929 for 2005, $142,860 for 2004, and $116,487 for 2003.

(4) Includes net plant of the former international segment as follows: $38 for 2007, $27 for 2006, $20 for 2005, $227,905 for 2004, and $219,199 for 2003.

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Item 7 ***Management's Discussion and Analysis of Financial Condition and Results of Operations***

OVERVIEW

The Company is a diversified energy company consisting of five reportable business segments. Refer to Item 1, Business, for a more detailed description of each of the segments. This Item 7, MD&A, provides information concerning:

1. The critical accounting estimates of the Company;
2. Changes in revenues and earnings of the Company under the heading, "Results of Operations;"
3. Operating, investing and financing cash flows under the heading "Capital Resources and Liquidity;"
4. Off-Balance Sheet Arrangements;
5. Contractual Obligations; and
6. Other Matters, including: (a) 2007 and 2008 funding to the Company's defined benefit retirement plan and post-retirement benefit plan, (b) realizability of deferred tax assets, (c) disclosures and tables concerning market risk sensitive instruments, (d) rate and regulatory matters in the Company's New York, Pennsylvania and FERC regulated jurisdictions, (e) environmental matters, and (f) new accounting pronouncements.

The information in MD&A should be read in conjunction with the Company's financial statements in Item 8 of this report.

The event that had the most significant earnings impact in 2007, and the main reason for the significant earnings increase over 2006, was the Company's sale of SECI, Seneca's wholly owned subsidiary that operated in Canada. SECI was engaged in the exploration for, and the development and purchase of, natural gas and oil reserves in the provinces of Alberta, Saskatchewan and British Columbia in Canada. This sale resulted in a $120.3 million gain, net of tax. The decision to sell SECI was based on lower than expected returns from the Canadian oil and gas properties combined with difficulty in finding significant new reserves. As a result of the decision to sell SECI, the Company began presenting all SECI operations as discontinued operations in September 2007. Also contributing to the increase in earnings over 2006 was the non-recurrence of impairment charges of $68.6 million related to the Exploration and Production segment's Canadian oil and gas assets recognized during 2006 under the full cost method of accounting, which is discussed below under Critical Accounting Estimates. Seneca intends to continue its exploration and development activities in the Gulf of Mexico, in California and in Appalachia, subject to regular re-evaluation of its efforts and opportunities in each region.

The Company spent $247.6 million on capital expenditures related to continuing operations during 2007, with approximately 59% being spent in the Exploration and Production segment. This was in line with the Company's expectations. As mentioned above, Seneca will continue its exploration and development activities in Appalachia, in California and in the Gulf of Mexico. In Appalachia, drilling will be accelerated. Seneca intends to commence drilling of 280 wells for shallow tight sand targets in fiscal 2008, a 20% increase over the 233 such wells drilled in 2007. In addition, Seneca anticipates continued drilling in the deeper Marcellus Shale formation in Appalachia with its joint venture partner, EOG Resources, Inc. Seneca expects that as many as eighteen Marcellus Shale wells will be drilled on its acreage in 2008, ten of which are expected to be horizontal wells. In the Gulf of Mexico, Seneca's strategy will be to follow a focused drilling plan in the specific areas where the Company has expertise and past success.

The Company took a significant step forward this year regarding the Empire Connector project. In June 2007, Empire signed a firm transportation service agreement with KeySpan Gas East Corporation, thereby obligating Empire to provide transportation service that will require construction of the Empire Connector project. Construction of the Empire Connector began in September 2007 and 20 miles will be completed by December 2007. The Company expects to complete the project by November 1, 2008. The total cost to the Company of the Empire Connector project is estimated at $177 million, after giving effect to sales tax

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exemptions. The Company expects the expansion of the Pipeline and Storage segment to remain a major strategic priority. Supply Corporation has verified that there is substantial market interest in transporting gas produced in the Rocky Mountain area to the Northeast. In order to serve this anticipated demand, Supply Corporation has proposed a new 324-mile pipeline that would commence at Clarington, Ohio, the proposed terminus of the Rockies Express pipeline, and extend to the Millennium Pipeline under construction at Corning, New York. From Corning, Rocky Mountain gas will be able to get to the New York City area and to New England. The proposed pipeline would be designed to move approximately 550 to 750 MDth of gas per day, as well as accommodate volumes from local production areas. These projects are discussed further in the Capital Resources and Liquidity and Rates and Regulatory Matters sections that follow.

The Company is currently evaluating the appropriateness of establishing a Master Limited Partnership (MLP) for its pipeline and storage assets, and another MLP for certain of its exploration and production assets. If this evaluation determined that the MLP structure is sound and in the shareholders' interest, the Company would pursue the MLP structure for the appropriate Company assets. Potential impediments to establishing MLPs include: (a) the low tax basis of our pipeline and storage assets, which substantially mitigates the tax advantages of an MLP structure; (b) the highly integrated operations of the Company's Pipeline and Storage and Utility business segments; and (c) the sustainability of an exploration and production MLP given the natural decline curve of production from all oil and gas properties. As a result, new long-lived reserves must be constantly added to an exploration and production MLP in order to sustain the MLP's cash distributions. Acquisitions of long-lived reserves could be very costly given the significant premiums that are currently being paid for long-lived reserves.

The Company also began repurchasing outstanding shares of common stock during fiscal 2006 under a share repurchase program authorized by the Company's Board of Directors. The program authorizes the Company to repurchase up to an aggregate amount of 8 million shares. Through September 30, 2007, the Company had repurchased 3,834,878 shares for $133.2 million under this program, including 1,308,328 shares for $48.1 million during the year ended September 30, 2007. These matters are discussed further in the Capital Resources and Liquidity section that follows.

On January 29, 2007, the Company commenced a rate case in the New York jurisdiction of the Utility segment by filing proposed tariff amendments and supporting testimony requesting approval to increase its annual revenues by $52.0 million annually. The Company explained in the filing that its request for rate relief is necessitated by decreased revenues resulting from customer conservation efforts and increased customer uncollectibles, among other things. The rate filing also includes a proposal for an aggressive efficiency and conservation initiative with a revenue decoupling mechanism designed to render the Company indifferent to throughput reductions resulting from conservation. In September 2007, the NYPSC issued an order approving the Company's conservation program, and the administrative law judge assigned to the proceeding issued a recommended decision, which recommends a rate increase designed to provide additional annual revenues of $2.5 million as well as a bill surcharge that would collect up to $10.8 million to recover expenses arising from the conservation program. The recommended decision also recommends approval of the unopposed revenue decoupling mechanism. The NYPSC is not bound to accept the recommended decision. This matter is discussed more fully in the Rate and Regulatory Matters section that follows.

CRITICAL ACCOUNTING ESTIMATES

The Company has prepared its consolidated financial statements in conformity with GAAP. The preparation of these financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. In the event estimates or assumptions prove to be different from actual results, adjustments are made in subsequent periods to reflect more current information. The following is a summary of the Company's most critical accounting estimates, which are defined as those estimates whereby judgments or uncertainties could affect the application of accounting policies and materially different amounts could be reported under different conditions or using different assumptions. For a complete discussion of the

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Company's significant accounting policies, refer to Item 8 at Note A — Summary of Significant Accounting Policies.

Oil and Gas Exploration and Development Costs. In the Company's Exploration and Production segment, oil and gas property acquisition, exploration and development costs are capitalized under the full cost method of accounting. Under this accounting methodology, all costs associated with property acquisition, exploration and development activities are capitalized, including internal costs directly identified with acquisition, exploration and development activities. The internal costs that are capitalized do not include any costs related to production, general corporate overhead, or similar activities. The Company does not recognize any gain or loss on the sale or other disposition of oil and gas properties unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves of oil and gas attributable to a cost center.

The Company believes that determining the amount of the Company's proved reserves is a critical accounting estimate. Proved reserves are estimated quantities of reserves that, based on geologic and engineering data, appear with reasonable certainty to be producible under existing economic and operating conditions. Such estimates of proved reserves are inherently imprecise and may be subject to substantial revisions as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. The estimates involved in determining proved reserves are critical accounting estimates because they serve as the basis over which capitalized costs are depleted under the full cost method of accounting (on a units-of-production basis). Unproved properties are excluded from the depletion calculation until proved reserves are found or it is determined that the unproved properties are impaired. All costs related to unproved properties are reviewed quarterly to determine if impairment has occurred. The amount of any impairment is transferred to the pool of capitalized costs being amortized.

In addition to depletion under the units-of-production method, proved reserves are a major component in the SEC full cost ceiling test. The full cost ceiling test is an impairment test prescribed by SEC Regulation S-X Rule 4-10. The ceiling test , which is performed each quarter, determines a limit, or ceiling, on a country-by-country basis on the amount of property acquisition, exploration and development costs that can be capitalized. The ceiling under this test represents (a) the present value of estimated future net cash flows, excluding future cash outflows associated with settling asset retirement obligations that have been accrued on the balance sheet, using a discount factor of 10%, which is computed by applying current market prices of oil and gas (as adjusted for hedging) to estimated future production of proved oil and gas reserves as of the date of the latest balance sheet, less estimated future expenditures, plus (b) the cost of unevaluated properties not being depleted, less (c) income tax effects related to the differences between the book and tax basis of the properties. The estimates of future production and future expenditures are based on internal budgets that reflect planned production from current wells and expenditures necessary to sustain such future production. The amount of the ceiling can fluctuate significantly from period to period because of additions or subtractions to proved reserves and significant fluctuations in oil and gas prices. The ceiling is then compared to the capitalized cost of oil and gas properties less accumulated depletion and related deferred income taxes. If the capitalized costs of oil and gas properties less accumulated depletion and related deferred taxes exceeds the ceiling at the end of any fiscal quarter, a non-cash impairment must be recorded to write down the book value of the reserves to their present value. This non-cash impairment cannot be reversed at a later date if the ceiling increases. It should also be noted that a non-cash impairment to write down the book value of the reserves to their present value in any given period causes a reduction in future depletion expense. Because of the decline in the price of natural gas during the third and fourth quarters of 2006, the book value of the Company's Canadian oil and gas properties exceeded the ceiling at both June 30, 2006 and September 30, 2006. Consequently, SECI recorded impairment charges of $62.4 million ($39.5 million after-tax) in the third quarter of 2006 and $42.3 million ($29.1 million after-tax) in the fourth quarter of 2006. These impairment charges are now included in the loss from discontinued operations for 2006 due to the sale of SECI during 2007.

It is difficult to predict what factors could lead to future impairments under the SEC's full cost ceiling test. As discussed above, fluctuations or subtractions to proved reserves and significant fluctuations in oil and gas prices have an impact on the amount of the ceiling at any point in time.

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Upon the adoption of SFAS 143 on October 1, 2002, the Company recorded an asset retirement obligation representing plugging and abandonment costs associated with the Exploration and Production segment's crude oil and natural gas wells and capitalized such costs in property, plant and equipment (i.e. the full cost pool). Prior to the adoption of SFAS 143, plugging and abandonment costs were accounted for solely through the Company's units-of-production depletion calculation. An estimate of such costs was added to the depletion base, which also included capitalized costs in the full cost pool and estimated future expenditures to be incurred in developing proved reserves. With the adoption of SFAS 143, plugging and abandonment costs are already included in capitalized costs and the units-of-production depletion calculation has been modified to exclude from the depletion base any estimate of future plugging and abandonment costs that are already recorded in the full cost pool.

Prior to the adoption of SFAS 143, in calculating the full cost ceiling, the Company reduced the future net cash flows from proved oil and gas reserves by the estimated plugging and abandonment costs. Such future net cash flows would then be compared to capitalized costs in the full cost pool, with any excess capitalized costs being expensed. With the adoption of SFAS 143, since the full cost pool now includes an amount associated with plugging and abandoning the wells, the calculation of the full cost ceiling has been changed so that future net cash flows from proved oil and gas reserves are no longer reduced by the estimated plugging and abandonment costs.

Regulation. The Company is subject to regulation by certain state and federal authorities. The Company, in its Utility and Pipeline and Storage segments, has accounting policies which conform to SFAS 71, and which are in accordance with the accounting requirements and ratemaking practices of the regulatory authorities. The application of these accounting policies allows the Company to defer expenses and income on the balance sheet as regulatory assets and liabilities when it is probable that those expenses and income will be allowed in the ratesetting process in a period different from the period in which they would have been reflected in the income statement by an unregulated company. These deferred regulatory assets and liabilities are then flowed through the income statement in the period in which the same amounts are reflected in rates. Management's assessment of the probability of recovery or pass through of regulatory assets and liabilities requires judgment and interpretation of laws and regulatory commission orders. If, for any reason, the Company ceases to meet the criteria for application of regulatory accounting treatment for all or part of its operations, the regulatory assets and liabilities related to those portions ceasing to meet such criteria would be eliminated from the balance sheet and included in the income statement for the period in which the discontinuance of regulatory accounting treatment occurs. Such amounts would be classified as an extraordinary item. For further discussion of the Company's regulatory assets and liabilities, refer to Item 8 at Note C — Regulatory Matters.

Accounting for Derivative Financial Instruments. The Company, in its Exploration and Production segment, Energy Marketing segment, Pipeline and Storage segment and All Other category, uses a variety of derivative financial instruments to manage a portion of the market risk associated with fluctuations in the price of natural gas and crude oil. These instruments are categorized as price swap agreements, no cost collars and futures contracts. The Company, in its Pipeline and Storage segment, previously used an interest rate collar to limit interest rate fluctuations on certain variable rate debt. In accordance with the provisions of SFAS 133, the Company accounted for these instruments as effective cash flow hedges or fair value hedges. In 2007, the Company discontinued hedge accounting for the interest rate collar, which resulted in a gain being recognized. Gains or losses associated with the derivative financial instruments are matched with gains or losses resulting from the underlying physical transaction that is being hedged. To the extent that the derivative financial instruments would ever be deemed to be ineffective based on the effectiveness testing, mark-to-market gains or losses from the derivative financial instruments would be recognized in the income statement without regard to an underlying physical transaction. As discussed below, the Company was required to discontinue hedge accounting for a portion of its derivative financial instruments in the Exploration and Production segment, resulting in a charge to earnings in 2005.

The Company uses both exchange-traded and non exchange-traded derivative financial instruments. The fair values of the non exchange-traded derivative financial instruments are based on valuations determined by the counterparties. Refer to the "Market Risk Sensitive Instruments" section below for further discussion of the Company's derivative financial instruments.

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Pension and Other Post-Retirement Benefits. The amounts reported in the Company's financial statements related to its pension and other post-retirement benefits are determined on an actuarial basis, which uses many assumptions in the calculation of such amounts. These assumptions include the discount rate, the expected return on plan assets, the rate of compensation increase and, for other post-retirement benefits, the expected annual rate of increase in per capita cost of covered medical and prescription benefits. The discount rate used by the Company is equal to the Moody's Aa Long-Term Corporate Bond index, rounded to the nearest 25 basis points. The duration of the securities underlying that index (approximately 13 years) reasonably matches the expected timing of anticipated future benefit payments (approximately 12 years). The Company also utilizes a yield curve model to determine the discount rate. The yield curve is a spot rate yield curve that provides a zero-coupon interest rate for each year into the future. Each year's anticipated benefit payments are discounted at the associated spot interest rate back to the measurement date. The discount rate is then determined based on the spot interest rate that results in the same present value when applied to the same anticipated benefit payments. The expected return on plan assets assumption used by the Company reflects the anticipated long-term rate of return on the plan's current and future assets. The Company utilizes historical investment data, projected capital market conditions, and the plan's target asset class and investment manager allocations to set the assumption regarding the expected return on plan assets. Changes in actuarial assumptions and actuarial experience could have a material impact on the amount of pension and post-retirement benefit costs and funding requirements experienced by the Company. However, the Company expects to recover substantially all of its net periodic pension and other post-retirement benefit costs attributable to employees in its Utility and Pipeline and Storage segments in accordance with the applicable regulatory commission authorization. For financial reporting purposes, the difference between the amounts of pension cost and post-retirement benefit cost recoverable in rates and the amounts of such costs as determined under applicable accounting principles is recorded as either a regulatory asset or liability, as appropriate, as discussed above under "Regulation." Pension and post-retirement benefit costs for the Utility and Pipeline and Storage segments represented 93% and 94%, respectively, of the Company's total pension and post-retirement benefit costs as determined under SFAS 87 and SFAS 106 for the years ended September 30, 2007 and 2006.

Changes in actuarial assumptions and actuarial experience could also have an impact on the benefit obligation and the funded status related to the Company's pension and post-retirement benefit plans and could impact the Company's equity. For example, while the discount rate used to determine benefit obligations did not change from 2006 to 2007, the discount rate was changed from 5.0% in 2005 to 6.25% in 2006. The change in the discount rate from 2005 to 2006 reduced the pension plan projected benefit obligation by $113.1 million and the accumulated post-retirement benefit obligation by $77.5 million. Other examples include actual versus expected return on plan assets, which has an impact on the funded status of the plans, and actual versus expected benefit payments, which has an impact on the pension plan projected benefit obligations and the accumulated post-retirement benefit obligation for the Post-Retirement Plan. For 2007, actual versus expected return on plan assets resulted in an increase to the funded status of the Retirement Plan and the Post-Retirement Plan of $68.4 million and $38.6 million, respectively. The actual versus expected benefit payments for 2007 caused a decrease of $1.3 million and $1.8 million to the projected benefit obligation and accumulated post-retirement benefit obligation, respectively. In calculating the projected benefit obligation for the Retirement Plan and the accumulated post-retirement obligation for the Post-Retirement Plan, the actuary takes into account the average remaining service life of active participants. The average remaining service life of active participants is 9 years for both the Retirement Plan and the Post-Retirement Plan. For further discussion of the Company's pension and other post-retirement benefits, refer to Other Matters in this Item 7, which includes a discussion of funding for the current year and the adoption of SFAS 158, and to Item 8 at Note G — Retirement Plan and Other Post Retirement Benefits.

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RESULTS OF OPERATIONS

EARNINGS

2007 Compared with 2006

The Company's earnings were $337.5 million in 2007 compared with earnings of $138.1 million in 2006. As previously discussed, the Company has presented its Canadian operations in the Exploration and Production segment (in conjunction with the sale of SECI) as discontinued operations. The Company's earnings from continuing operations were $201.7 million in 2007 compared with $184.6 million in 2006. The Company's earnings from discontinued operations were $135.8 million in 2007 compared with a loss of $46.5 million in 2006. The increase in earnings from continuing operations of $17.1 million is primarily the result of higher earnings in the Exploration and Production, Utility, Pipeline and Storage, and Energy Marketing segments and the Corporate and All Other categories, slightly offset by lower earnings in the Timber segment, as shown in the table below. The increase in earnings from discontinued operations primarily resulted from the gain on the sale of SECI recognized in 2007 as well as the non-recurrence of $68.6 million of impairment charges recognized in 2006 related to the Exploration and Production segment's Canadian oil and gas assets. In the discussion that follows, note that all amounts used in the earnings discussions are after-tax amounts, unless otherwise noted. Earnings from continuing operations and discontinued operations were impacted by several events in 2007 and 2006, including:

2007 Events

- A $120.3 million gain on the sale of SECI, which was completed in August 2007. This amount is included in earnings from discontinued operations;
- A $4.8 million benefit to earnings in the Pipeline and Storage segment due to the reversal of a reserve established for all costs incurred related to the Empire Connector project recognized during June 2007;
- A $1.9 million benefit to earnings in the Pipeline and Storage segment associated with the discontinuance of hedge accounting for Empire's interest rate collar; and
- A $2.3 million benefit to earnings in the Energy Marketing segment related to the resolution of a purchased gas contingency.

2006 Events

- $68.6 million of impairment charges related to the Exploration and Production segment's Canadian oil and gas assets under the full cost method of accounting using natural gas pricing at June 30, 2006 and September 30, 2006;
- An $11.2 million benefit to earnings in the Exploration and Production segment ($6.1 million in continuing operations and $5.1 million in discontinued operations) related to income tax adjustments recognized during 2006; and
- A $2.6 million benefit to earnings in the Utility segment related to the correction of Distribution Corporation's calculation of the symmetrical sharing component of New York's gas adjustment rate.

2006 Compared with 2005

The Company's earnings were $138.1 million in 2006 compared with earnings of $189.5 million in 2005. As previously discussed, the Company has presented its Canadian operations in the Exploration and Production segment (in conjunction with the sale of SECI) as well as for its Czech Republic operations (in conjunction with the sale of U.E.) as discontinued operations. The Company's earnings from continuing operations were $184.6 million in 2006 compared with $138.4 million in 2005. The Company recorded a loss from discontinued operations of $46.5 million in 2006 compared with earnings from discontinued operations of $51.1 million in 2005. The increase in earnings from continuing operations of $46.2 million is primarily the result of higher earnings in the Exploration and Production, Utility, Energy Marketing, and Timber segments, combined with

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higher earnings in the All Other category and a lower loss in the Corporate category. These were offset somewhat by lower earnings in the Pipeline and Storage segment, as shown in the table below. The loss from discontinued operations in 2006 compared to earnings from discontinued operations in 2005 reflects the recognition of $68.6 million of impairment charges in 2006 related to the Exploration and Production segment's Canadian oil and gas assets as well as the non-recurrence of the gain on the sale of U.E. recognized in 2005. Earnings from continuing operations and discontinued operations were impacted by several events discussed above and the following 2005 events:

2005 Events

- A $25.8 million gain on the sale of U.E., which was completed in July 2005. This amount is included in earnings from discontinued operations;
- A $2.6 million gain in the Pipeline and Storage segment associated with a FERC approved sale of base gas;
- A $3.9 million gain in the Pipeline and Storage segment associated with insurance proceeds received in prior years for which a contingency was resolved during 2005;
- A $3.3 million loss related to certain derivative financial instruments that no longer qualified as effective hedges;
- A $2.7 million impairment in the value of the Company's 50% investment in ESNE (recorded in the All Other category), a limited liability company that owns an 80-megawatt, combined cycle, natural gas-fired power plant in the town of North East, Pennsylvania; and
- A $1.8 million impairment of a gas-powered turbine in the All Other category that the Company had planned to use in the development of a co-generation plant.

Additional discussion of earnings in each of the business segments can be found in the business segment information that follows.

Earnings (Loss) by Segment

	Year Ended September 30		
	2007	2006	2005
		(Thousands)	
Utility	$ 50,886	$ 49,815	$ 39,197
Pipeline and Storage	56,386	55,633	60,454
Exploration and Production	74,889	67,494	35,581
Energy Marketing	7,663	5,798	5,077
Timber	3,728	5,704	5,032
Total Reportable Segments	193,552	184,444	145,341
All Other	2,564	359	(2,616)
Corporate(1)	5,559	(189)	(4,288)
Total Earnings from Continuing Operations	201,675	184,614	138,437
Earnings (Loss) from Discontinued Operations	135,780	(46,523)	51,051
Total Consolidated	$ 337,455	$ 138,091	$ 189,488

(1) Includes earnings from the former International segment's activity other than the activity from the Czech Republic operations included in Earnings from Discontinued Operations.

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UTILITY

Revenues

Utility Operating Revenues

	Year Ended September 30		
	2007	2006	2005
		(Thousands)	
Retail Revenues:			
Residential	$ 848,693	$ 993,928	$ 868,292
Commercial	136,863	166,779	145,393
Industrial	8,271	13,484	13,998
	993,827	1,174,191	1,027,683
Off-System Sales	9,751	—	—
Transportation	102,534	92,569	83,669
Other	14,612	14,003	5,715
	$ 1,120,724	$ 1,280,763	$ 1,117,067

Utility Throughput — million cubic feet (MMcf)

	Year Ended September 30		
	2007	2006	2005
Retail Sales:			
Residential	60,236	59,443	66,903
Commercial	10,713	10,681	11,984
Industrial	727	985	1,387
	71,676	71,109	80,274
Off-System Sales	1,355	—	—
Transportation	62,240	57,950	59,770
	135,271	129,059	140,044

Degree Days

				Percent (Warmer) Colder Than	
Year Ended September 30		Normal	Actual	Normal	Prior Year
2007:	Buffalo	6,692	6,271	(6.3)%	5.1%
	Erie	6,243	6,007	(3.8)%	5.6%
2006:	Buffalo	6,692	5,968	(10.8)%	(9.4)%
	Erie	6,243	5,688	(8.9)%	(8.9)%
2005:	Buffalo	6,692	6,587	(1.6)%	0.2%
	Erie	6,243	6,247	0.1%	2.6%

2007 Compared with 2006

Operating revenues for the Utility segment decreased $160.0 million in 2007 compared with 2006. This decrease largely resulted from a $180.4 million decrease in retail gas sales revenues. This decrease was primarily offset by a $10.0 million increase in transportation revenues and a $9.8 million increase in off-system sales revenues.

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The decrease in retail gas sales revenues for the Utility segment was largely a function of the recovery of lower gas costs (gas costs are recovered dollar for dollar in revenues), which more than offset the revenue impact of higher retail sales volumes, as shown in the table above. See further discussion of purchased gas below under the heading "Purchased Gas." This decrease was offset slightly by a base rate increase in the Pennsylvania jurisdiction, effective January 2007, which increased operating revenues by $8.5 million for 2007. The increase is included within both retail and transportation revenues in the table above.

The increase in transportation revenues was primarily due to a 4.3 Bcf increase in transportation throughput, largely due to the migration of retail sales customers to transportation service. The corresponding $10.0 million increase in transportation revenues would have been greater if not for a $3.9 million out-of-period adjustment recorded in the first quarter of 2006 to correct Distribution Corporation's calculation of the symmetrical sharing component of New York's gas adjustment rate.

As reported in 2006, on November 17, 2006 the U.S. Court of Appeals vacated and remanded FERC's Order No. 2004, its latest affiliate standards of conduct, with respect to natural gas pipelines. The court's decision became effective on January 5, 2007, and on January 9, 2007, FERC issued Order No. 690, its Interim Rule, designed to respond to the court's decision. In Order No. 690, as clarified by FERC on March 21, 2007, the FERC readopted, on an interim basis, certain provisions that existed prior to the issuance of Order No. 2004 that had made it possible for the Utility to engage in certain off-system sales without triggering the adverse consequences that would otherwise arise under the standards of conduct. As such, the Utility resumed engaging in off-system sales on non-affiliated pipelines as of May 2007, resulting in total off-system sales revenues of $9.8 million for 2007. Due to profit sharing with retail customers, the margins resulting from off-system sales are minimal and there was not a material impact to margins in 2007.

2006 Compared with 2005

Operating revenues for the Utility segment increased $163.7 million in 2006 compared with 2005. This increase largely resulted from a $146.5 million increase in retail gas sales revenues. Transportation revenues and other revenues also increased by $8.9 million and $8.3 million, respectively.

The increase in retail gas sales revenues for the Utility segment was largely a function of the recovery of higher gas costs (gas costs are recovered dollar for dollar in revenues), which more than offset the revenue impact of lower retail sales volumes, as shown in the table above. See further discussion of purchased gas below under the heading "Purchased Gas." Warmer weather, as shown in the table above, and greater conservation by customers due to higher natural gas commodity prices, were the principal reasons for the decrease in retail sales volumes.

The increase in transportation revenues was primarily due to a $5.9 million increase in the New York jurisdiction's calculation of the symmetrical sharing component of the gas adjustment rate. The symmetrical sharing component is a mechanism included in Distribution Corporation's New York rate agreement that shares with customers 90% of the difference between actual revenues received from large volume customers and the level of revenues that were projected to be received during the rate year. Of the $5.9 million increase, $3.9 million was due to an out-of-period adjustment recorded in fiscal year 2006 when it was determined that certain credits that had been included in the calculation should have been removed during the implementation of a previous rate case. The adjustment related to fiscal years 2002 through 2005.

The impact of the August 2005 New York rate agreement was to increase operating revenues by $19.1 million (of which $12.4 million was an increase to other operating revenues). This increase consisted of a base rate increase, the implementation of a merchant function charge, the elimination of certain bill credits, and the elimination of the gross receipts tax surcharge. The rate agreement also allowed Distribution Corporation to continue to utilize certain refunds from upstream pipeline companies and certain other credits (referred to as the "cost mitigation reserve") to offset certain specific expense items. In 2005, Distribution Corporation utilized $7.8 million of the cost mitigation reserve, which increased other operating revenues, to recover previous under-collections of pension and post-retirement expenses. The impact of that increase in other operating revenues was offset by an equal amount of operation and maintenance expense (thus there was no earnings impact). Distribution Corporation did not record any entries involving the cost mitigation reserve

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in 2006. Other operating revenues were also impacted by two out-of-period regulatory adjustments recorded during 2005. The first adjustment related to the final settlement with the Staff of the NYPSC of the earnings sharing liability for the 2001 to 2003 time period. As a result of that settlement, the New York rate jurisdiction recorded additional earnings sharing expense (as an offset to other operating revenues) of $0.9 million. The second adjustment related to a regulatory liability recorded for previous over-collections of New York State gross receipts tax. In preparing for the implementation of the rate agreement in New York, the Company determined that it needed to adjust that regulatory liability by $3.1 million (of which $1.0 million was recorded as a reduction of other operating revenues and $2.1 million was recorded as additional interest expense) related to fiscal years 2004 and prior. These adjustments did not recur in 2006.

In the Pennsylvania jurisdiction, the impact of the base rate increase, which became effective in mid-April 2005, was to increase operating revenues by $7.5 million. This increase is included within both retail and transportation revenues in the table above.

Purchased Gas

The cost of purchased gas is the Company's single largest operating expense. Annual variations in purchased gas costs are attributed directly to changes in gas sales volumes, the price of gas purchased and the operation of purchased gas adjustment clauses.

Currently, Distribution Corporation has contracted for long-term firm transportation capacity with Supply Corporation and six other upstream pipeline companies, for long-term gas supplies with a combination of producers and marketers, and for storage service with Supply Corporation and three nonaffiliated companies. In addition, Distribution Corporation satisfies a portion of its gas requirements through spot market purchases. Changes in wellhead prices have a direct impact on the cost of purchased gas. Distribution Corporation's average cost of purchased gas, including the cost of transportation and storage, was $10.04 per Mcf in 2007, a decrease of 17% from the average cost of $12.07 per Mcf in 2006. The average cost of purchased gas in 2006 was 31% higher than the average cost of $9.19 per Mcf in 2005. Additional discussion of the Utility segment's gas purchases appears under the heading "Sources and Availability of Raw Materials" in Item 1.

Earnings

2007 Compared with 2006

The Utility segment's earnings in 2007 were $50.9 million, an increase of $1.1 million when compared with earnings of $49.8 million in 2006.

In the New York jurisdiction, earnings decreased by $6.2 million. This was primarily due to lower interest income ($4.5 million). The New York division's current rate agreement with the NYPSC allows the Company to accrue interest on a pension-related regulatory asset. The amount of interest that can be accrued is reduced as the funded status of the pension plan improves. The fair market value of the pension plan assets exceeded the accumulated benefit obligation at September 30, 2007 resulting in a significant reduction in the interest accrual on this regulatory asset. The out-of-period symmetrical sharing adjustment discussed above ($2.6 million), higher bad debt and other operating costs ($0.8 million), higher property taxes ($0.6 million) and higher interest expense ($0.5 million) also contributed to this decrease. The positive impact associated with a lower effective tax rate ($1.9 million) and increased usage per account ($1.9 million) partially offset the overall decrease.

In the Pennsylvania jurisdiction, earnings increased by $7.3 million. This was primarily due to a base rate increase ($5.5 million) that became effective January 2007, colder weather ($2.5 million), and the positive impact associated with a lower effective tax rate ($1.1 million). Higher intercompany and other interest expense ($0.8 million), coupled with a decrease in normalized usage ($0.3 million), partially offset these increases.

The impact of weather on the Utility segment's New York rate jurisdiction is tempered by a WNC. The WNC, which covers the eight-month period from October through May, has had a stabilizing effect on earnings for the New York rate jurisdiction. In addition, in periods of colder than normal weather, the WNC benefits the

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Utility segment's New York customers. In 2007 and 2006, the WNC preserved earnings of approximately $2.3 million and $6.2 million, respectively, as the weather was warmer than normal.

2006 Compared with 2005

The Utility segment's earnings in 2006 were $49.8 million, an increase of $10.6 million when compared with earnings of $39.2 million in 2005.

In the New York jurisdiction, earnings increased by $9.2 million, primarily due to the positive impact of the rate agreement in this jurisdiction that became effective August 2005 ($13.7 million). In addition, the increase in the New York jurisdiction's calculation of the symmetrical sharing component of the gas adjustment rate, including the out-of-period adjustment discussed above, contributed $3.9 million to earnings. Two out-of-period regulatory adjustments recorded during fiscal year 2005 that did not recur during 2006, as discussed above, also contributed an additional $2.6 million to earnings. The first adjustment, related to the final settlement with the Staff of the NYPSC of the earnings sharing liability for the fiscal 2001 through 2003 time period, increased earnings in fiscal 2006 by $0.6 million. The second adjustment, related to a regulatory liability recorded for previous over-collections of New York State gross receipts tax, increased earnings in fiscal 2006 by $2.0 million. The increase in earnings due to the New York rate agreement, the symmetrical sharing component of the gas adjustment rate, and the two out-of-period regulatory adjustments recorded in 2005, was partially offset by a decline in margin associated with lower weather-normalized usage by customers ($2.3 million), higher operation expenses ($2.5 million), higher interest expense ($2.7 million), and a higher effective income tax rate ($3.2 million). The higher effective income tax rate is due to positive tax adjustments recorded in 2005 that did not recur in 2006. The increase in operation expenses consisted primarily of higher pension expense offset by lower bad debt expense.

In the Pennsylvania jurisdiction, earnings increased by $1.4 million, due to the positive impact of the rate case settlement in this jurisdiction that became effective April 2005 ($4.9 million), and lower operation expenses ($1.8 million). The decrease in operation expenses consisted primarily of lower bad debt expense offset partially by higher pension expense. These increases to earnings were partially offset by the impact of warmer than normal weather in Pennsylvania ($3.0 million), lower weather-normalized usage by customer ($0.6 million), higher interest expense ($0.8 million), and a higher effective tax rate ($1.3 million).

The decrease in bad debt expense reflects the fact that in the fourth quarter of 2005, the New York and Pennsylvania jurisdictions increased the allowance for uncollectible accounts to reflect the increase in final billed account balances and the increased aging of outstanding active receivables heading into the heating season. A similar adjustment was not required in 2006.

In 2006, the WNC preserved earnings of approximately $6.2 million because it was warmer than normal in the New York service territory. In 2005, the WNC did not have a significant impact on earnings.

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PIPELINE AND STORAGE

Revenues

Pipeline and Storage Operating Revenues

	Year Ended September 30		
	2007	2006	2005
		(Thousands)	
Firm Transportation	$ 118,771	$ 118,551	$ 117,146
Interruptible Transportation	4,161	4,858	4,413
	122,932	123,409	121,559
Firm Storage Service	66,966	66,718	65,320
Interruptible Storage Service	169	39	267
	67,135	66,757	65,587
Other	21,899	24,186	28,713
	$ 211,966	$ 214,352	$ 215,859

Pipeline and Storage Throughput — (MMcf)

	Year Ended September 30		
	2007	2006	2005
Firm Transportation	351,113	363,379	357,585
Interruptible Transportation	4,975	11,609	14,794
	356,088	374,988	372,379

2007 Compared with 2006

Operating revenues for the Pipeline and Storage segment decreased $2.4 million in 2007 as compared with 2006, which was due mostly to a decrease in other revenues ($2.3 million). The decrease in other revenues is primarily due to a $4.2 million decrease in efficiency gas revenues. This decrease was due to the Company's recent settlement with the FERC, which decreased efficiency gas retainage allowances. Offsetting this decrease, there was a $1.4 million increase in other revenues attributable to the lease termination fee adjustment in 2006 (an intercompany transaction) for the Company's former headquarters, which did not recur in 2007. While Supply Corporation's transportation volumes decreased during the year, volume fluctuations generally do not have a significant impact on revenues as a result of Supply Corporation's straight-fixed variable rate design.

2006 Compared with 2005

Operating revenues for the Pipeline and Storage segment decreased $1.5 million in 2006 as compared with 2005. This decrease consisted of a $4.5 million decrease in other revenues offset by a $1.8 million increase in firm and interruptible transportation revenues and a $1.2 million increase in firm and interruptible storage service revenues. The decrease in other revenues is primarily due to a $2.6 million decrease in efficiency gas revenues due to lower natural gas prices, a $0.7 million decrease in cashout revenues, and a $1.4 million decrease in revenue attributable to a lease termination fee adjustment (an intercompany transaction) for the Company's former headquarters. Cashout revenues are completely offset by purchased gas expense. The increase in firm and interruptible transportation revenues is due to additional contracts with customers and the renewal of contracts at higher rates, both of which reflect the increased demand for transportation services due to market conditions resulting from the effects of hurricane damage to production and pipeline infrastructure in the Gulf of Mexico during the fall of 2005. While Supply Corporation's transportation volumes increased during the year, volume fluctuations generally do not have a significant impact on revenues as a result of Supply

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Corporation's straight fixed-variable rate design. The increase in storage revenues reflects the renewal of storage contracts at higher rates.

Earnings

2007 Compared with 2006

The Pipeline and Storage segment's earnings in 2007 were $56.4 million, an increase of $0.8 million when compared with earnings of $55.6 million in 2006. The main factor contributing to this increase was the reversal of a reserve for preliminary survey costs ($4.8 million) related to the Empire Connector project. Based on the signing of a service agreement with KeySpan Gas East Corporation during the quarter ended June 30, 2007, management determined that it was probable that the project would go forward and that such preliminary survey costs were properly capitalizable in accordance with the FERC's Uniform System of Accounts and SFAS 71. In addition, there was a $2.5 million increase in earnings associated with the decrease in depreciation expense as a result of the most recent settlement with the FERC, which reduced depreciation rates. There was also a $1.9 million positive earnings impact associated with the discontinuance of hedge accounting for Empire's interest rate collar. On December 8, 2006, Empire repaid $22.8 million of secured debt. The interest costs of this secured debt were hedged by the interest rate collar. Since the hedged transaction was settled and there will be no future cash flows associated with the secured debt, the unrealized gain in accumulated other comprehensive income associated with the interest rate collar was reclassified to the income statement. These earnings increases were offset by higher interest expense ($3.2 million), lower efficiency gas revenues ($2.7 million), a $1.5 million increase in operating costs (primarily post-retirement benefit costs), and the earnings decrease associated with a higher effective tax rate ($0.9 million).

2006 Compared with 2005

The Pipeline and Storage segment's earnings in 2006 were $55.6 million, a decrease of $4.9 million when compared with earnings of $60.5 million in 2005. The decrease reflects the non-recurrence of two events, a $2.6 million gain on a FERC approved sale of base gas in 2005 and a $3.9 million gain associated with insurance proceeds received in prior years for which a contingency was resolved in 2005. Both of these items were recorded in Other Income. It also reflects the earnings impact associated with lower efficiency gas revenues ($1.7 million) and higher operation expenses ($0.6 million). These earnings decreases were offset by the positive earnings impact of higher transportation and storage revenues ($2.0 million), lower depreciation due to the non-recurrence of a write-down of the Company's former corporate office in 2005 ($0.9 million), and the earnings benefit associated with a lower effective tax rate ($1.7 million).

EXPLORATION AND PRODUCTION

Revenues

Exploration and Production Operating Revenues

	Year Ended September 30		
	2007	2006	2005
		(Thousands)	
Gas (after Hedging) from Continuing Operations	$ 143,785	$ 126,969	$ 132,528
Oil (after Hedging) from Continuing Operations	167,627	134,307	94,925
Gas Processing Plant from Continuing Operations	37,528	42,252	36,350
Other from Continuing Operations	1,147	3,072	(3,447)
Intrasegment Elimination from Continuing Operations(1)	(26,050)	(31,704)	(29,706)
Operating Revenues from Continuing Operations	$ 324,037	$ 274,896	$ 230,650
Operating Revenues from Canada — Discontinued Operations	$ 50,495	$ 71,984	$ 62,775

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(1) Represents the elimination of certain West Coast gas production revenue included in "Gas (after Hedging) from Continuing Operations" in the table above that is sold to the gas processing plant shown in the table above. An elimination for the same dollar amount was made to reduce the gas processing plant's Purchased Gas expense.

Production Volumes

	Year Ended September 30		
	2007	2006	2005
Gas Production *(MMcf)*			
Gulf Coast	10,356	9,110	12,468
West Coast	3,929	3,880	4,052
Appalachia	5,555	5,108	4,650
Total Production from Continuing Operations	19,840	18,098	21,170
Canada — Discontinued Operations	6,426	7,673	8,009
Total Production	26,266	25,771	29,179
Oil Production *(Mbbl)*			
Gulf Coast	717	685	989
West Coast	2,403	2,582	2,544
Appalachia	124	69	36
Total Production from Continuing Operations	3,244	3,336	3,569
Canada — Discontinued Operations	206	272	300
Total Production	3,450	3,608	3,869

Average Prices

	Year Ended September 30		
	2007	2006	2005
Average Gas Price/Mcf			
Gulf Coast	$ 6.58	$ 8.01	$ 7.05
West Coast	$ 6.54	$ 7.93	$ 6.85
Appalachia	$ 7.48	$ 9.53	$ 7.60
Weighted Average for Continuing Operations	$ 6.82	$ 8.42	$ 7.13
Weighted Average After Hedging for Continuing Operations(1)	$ 7.25	$ 7.02	$ 6.26
Canada — Discontinued Operations	$ 6.09	$ 7.14	$ 6.15
Average Oil Price/Barrel (bbl)			
Gulf Coast	$ 63.04	$ 64.10	$ 49.78
West Coast(2)	$ 56.86	$ 56.80	$ 42.91
Appalachia	$ 62.26	$ 65.28	$ 48.28
Weighted Average for Continuing Operations	$ 58.43	$ 58.47	$ 44.87
Weighted Average After Hedging for Continuing Operations(1)	$ 51.68	$ 40.26	$ 26.59
Canada — Discontinued Operations	$ 50.06	$ 51.40	$ 42.97

(1) Refer to further discussion of hedging activities below under "Market Risk Sensitive Instruments" and in Note F — Financial Instruments in Item 8 of this report.

(2) Includes low gravity oil which generally sells for a lower price.

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2007 Compared with 2006

Operating revenues from continuing operations for the Exploration and Production segment increased $49.1 million in 2007 as compared with 2006. Oil production revenue after hedging increased $33.3 million due primarily to an $11.42 per barrel increase in weighted average prices after hedging, which more than offset a slight decrease in oil production of 92,000 barrels. Gas production revenue after hedging increased $16.8 million in 2007 as compared with 2006. An increase in gas production of 1,742 MMcf and an increase in weighted average prices after hedging of $0.23 per Mcf both contributed to the increase. The increase in gas production occurred primarily in the Gulf Coast region (1,246 MMcf). During the quarter ended December 31, 2005, Seneca experienced significant production delays due largely to the impact of hurricane damage to pipeline infrastructure in the Gulf of Mexico. Seneca had substantially all of its pre-hurricane Gulf of Mexico production back on line at the beginning of fiscal 2007. Production also increased in this segment's Appalachian region (447 MMcf), primarily due to increased drilling in this region during 2007, as highlighted in Item 2 under "Exploration and Production Activities."

Refer to further discussion of derivative financial instruments in the "Market Risk Sensitive Instruments" section that follows. Refer to the tables above for production and price information.

2006 Compared with 2005

Operating revenues from continuing operations for the Exploration and Production segment increased $44.2 million in 2006 as compared with 2005. Oil production revenue after hedging increased $39.4 million due primarily to higher weighted average prices after hedging ($13.67 per barrel). This increase was offset slightly by a decrease in production (233,000 barrels). Gas production revenue after hedging decreased $5.6 million. A decrease in gas production (3,072 MMcf) more than offset an increase in the weighted average price of gas after hedging ($0.76 per Mcf). The decrease in gas production occurred primarily in the Gulf Coast (a 3,358 MMcf decline), which is partly attributable to the fall 2005 hurricane damage and partly attributable to the expected decline rates for the Company's production in the region. Other revenues increased $6.5 million largely due to the non-recurrence of a $5.1 million mark-to-market adjustment, recorded in 2005, for losses on certain derivative financial instruments that no longer qualified as effective hedges due to the anticipated delays in oil and gas production volumes caused by Hurricane Rita.

Refer to further discussion of derivative financial instruments in the "Market Risk Sensitive Instruments" section that follows. Refer to the tables above for production and price information.

Earnings

2007 Compared with 2006

The Exploration and Production segment's earnings from continuing operations for 2007 were $74.9 million, an increase of $7.4 million when compared with earnings from continuing operations of $67.5 million for 2006. Higher crude oil prices, higher natural gas production and higher natural gas prices increased earnings by $24.1 million, $7.9 million and $3.0 million, respectively. These increases were partly offset by the non-recurrence of $6.1 million of tax benefits recognized during 2006, discussed below, as well as by higher depletion expense and higher lease operating expense of $7.2 million and $4.6 million, respectively. Slightly lower crude oil production and higher general and administrative expenses also decreased earnings by $2.4 million and $0.6 million, respectively. Earnings were also negatively impacted by a higher effective tax rate ($6.3 million).

2006 Compared with 2005

The Exploration and Production segment's earnings from continuing operations in 2006 were $67.5 million, an increase of $31.9 million when compared with earnings from continuing operations of $35.6 million in 2005. The increase is primarily the result of higher oil and gas prices, which increased earnings by $29.6 million and $8.9 million, respectively. Also, the non-recurrence of the 2005 mark-to-market adjustment discussed under Revenues above, contributed $3.3 million to earnings and strong cash flow provided higher interest

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income ($2.2 million). In the third quarter of 2006, a $6.1 million benefit to earnings related to income taxes was recognized. The Company reversed a valuation allowance ($2.9 million) associated with the capital loss carryforward that resulted from the 2003 sale of certain of Seneca's oil properties, and also recognized a tax benefit of $3.2 million related to the favorable resolution of certain open tax issues. Partly offsetting these increases, lower gas and oil production decreased earnings by $12.5 million and $4.0 million, respectively. Further contributing to the decrease were higher general and administrative and other operating costs ($2.0 million) and higher lease operating expenses ($1.9 million). The increase in lease operating expenses was primarily in the West Coast region due to higher steaming costs associated with heavy crude oil production in the California Midway-Sunset and North Lost Hills fields. The higher steaming costs were due to an increase in the price for natural gas purchased in the field and used in the steaming operations, primarily in the second quarter of fiscal 2006, compared to the second quarter of fiscal 2005.

ENERGY MARKETING

Revenues

Energy Marketing Operating Revenues

	Year Ended September 30		
	2007	2006 (Thousands)	2005
Natural Gas (after Hedging)	$ 413,405	$ 496,769	$ 329,560
Other	207	300	154
	$ 413,612	$ 497,069	$ 329,714

Energy Marketing Volumes

	Year Ended September 30		
	2007	2006	2005
Natural Gas — (MMcf)	50,775	45,270	40,683

2007 Compared with 2006

Operating revenues for the Energy Marketing segment decreased $83.5 million in 2007 as compared with 2006. The decrease primarily reflects lower gas sales revenue due to a decrease in natural gas commodity prices for the period that were recovered through revenues, offset in part by an increase in throughput. The increase in throughput was due to the addition of certain large, low-margin commercial and industrial customers, an increase in sales to wholesale customers, and colder weather.

2006 Compared with 2005

Operating revenues for the Energy Marketing segment increased $167.4 million in 2006 as compared with 2005. The increase primarily reflects higher natural gas commodity prices that were recovered through revenues, and, to a lesser extent, an increase in throughput. The increase in throughput was due to the addition of certain large commercial and industrial customers, which more than offset any decrease in throughput due to warmer weather and greater conservation by customers due to higher natural gas prices.

Earnings

2007 Compared with 2006

The Energy Marketing segment's earnings in 2007 were $7.7 million, an increase of $1.9 million when compared with earnings of $5.8 million in 2006. Higher margins of $2.3 million are responsible for the increase in earnings. The increase in margin is mainly the result of a $2.3 million reversal of an accrual for purchased gas expense related to the resolution of a contingency during 2007. While throughput increased, as noted above, much of this increase in volume is related to sales to low margin customers.

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2006 Compared with 2005

The Energy Marketing segment's earnings in 2006 were $5.8 million, an increase of $0.7 million when compared with earnings of $5.1 million in 2005. Despite warmer weather and greater conservation by customers, gross margin increased due to a number of factors, including higher volumes and the marketing flexibility associated with stored gas. The Energy Marketing segment's contracts for significant storage and transportation volumes provided operational flexibility resulting in increased sales throughput and earnings. The increase in gross margin more than offset an increase in operation expense.

TIMBER

Revenues

Timber Operating Revenues

	Year Ended September 30		
	2007	2006 (Thousands)	2005
Log Sales	$ 21,927	$ 23,077	$ 22,478
Green Lumber Sales	5,097	7,123	7,296
Kiln-dried Lumber Sales	27,908	32,809	29,651
Other	3,965	2,020	1,861
	$ 58,897	$ 65,029	$ 61,286

Timber Board Feet

	Year Ended September 30		
	2007	2006 (Thousands)	2005
Log Sales	8,660	9,527	7,601
Green Lumber Sales	9,358	10,454	10,489
Kiln-dried Lumber Sales	14,778	16,862	15,491
	32,796	36,843	33,581

2007 Compared with 2006

Operating revenues for the Timber segment decreased $6.1 million in 2007 as compared with 2006. This decrease is attributed to unfavorable weather conditions primarily during the fall of 2006 and the spring of 2007 that greatly limited the harvesting of logs. These conditions consisted of warm, wet weather that made it difficult to bring logging trucks into the forests. Weather conditions were significantly more favorable throughout fiscal 2006. These unfavorable conditions for harvesting resulted in a decline in log sales of $1.2 million or 867,000 board feet. There was also a decline in both green lumber and kiln-dried lumber sales of $2.0 million and $4.9 million, respectively, primarily because there were fewer logs available for processing. Declines in market prices for the cherry and maple species also contributed to the decrease in green lumber and kiln-dried lumber sales. Additionally, the processing of a greater amount of lumber species other than cherry (due to the mix of species on the areas being harvested) contributed to the decline in kiln-dried lumber sales since lumber species other than cherry are sold at a lower price than kiln-dried cherry lumber. With the addition of two new kilns placed into service in June 2007 that allow for greater processing capacity, the Company plans to continue to focus on increasing cherry kiln-dried lumber sales since cherry kiln-dried lumber commands a higher price in the overall mix of lumber. Offsetting the decreases discussed above, other revenues increased $1.9 million largely due to the sale of 3.1 million board feet of timber rights ($1.6 million).

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2006 Compared with 2005

Operating revenues for the Timber segment increased $3.7 million in 2006 as compared with 2005. This increase is attributed to an increase in kiln-dried lumber sales of $3.2 million primarily due to an increase in kiln-dried cherry lumber sales volumes of 2.0 million board feet. Other kiln-dried lumber sales volumes decreased by 0.6 million board feet, but there was little impact to revenues. The addition of two new kilns in February 2005 allowed for greater processing capacity in 2006 as compared to 2005 since the kilns were in operation for all of 2006. Higher log sales revenue of $0.6 million also contributed to the increase in revenues. An increase in cherry export log sales as a result of greater market demand and an increase in saw log sales were the primary factors contributing to the increase. Offsetting these increases was a decline in cherry veneer log sales due to lower volumes of cherry veneer logs harvested because of unfavorable weather conditions.

Earnings

2007 Compared with 2006

The Timber segment earnings in 2007 were $3.7 million, a decrease of $2.0 million when compared with earnings of $5.7 million in 2006. The decrease was primarily due to lower margins from lumber and log sales ($2.5 million) as a result of the decline in revenues noted above, as well as higher general and administrative expenses of $0.3 million. Partially offsetting this decrease was a decline in depletion expense of $1.2 million. The decrease in depletion expense reflects the cutting of more low cost or no cost basis timber from Company owned land as well as the overall decrease in logs harvested.

2006 Compared with 2005

The Timber segment earnings in 2006 were $5.7 million, an increase of $0.7 million when compared with earnings of $5.0 million in 2005. Higher margins from kiln-dried lumber sales and cherry export log sales accounted for the earnings increase.

ALL OTHER AND CORPORATE OPERATIONS

All Other and Corporate Operations primarily includes the operations of Horizon LFG, Horizon Power, former International segment activity other than the activity from the Czech Republic operations, and corporate operations. Horizon LFG owns and operates short-distance landfill gas pipeline companies. Horizon Power's activity primarily consists of equity method investments in Seneca Energy, Model City and ESNE. Horizon Power has a 50% ownership interest in each of these entities. The income from these equity method investments is reported as Income from Unconsolidated Subsidiaries on the Consolidated Statements of Income. Seneca Energy and Model City generate and sell electricity using methane gas obtained from landfills owned by outside parties. ESNE generates electricity from an 80-megawatt, combined cycle, natural gas-fired power plant in North East, Pennsylvania. Horizon Power also owns a gas-powered turbine and other assets which it had planned to use in the development of a co-generation plant. The Company is in the process of selling these assets. The former International segment activity primarily consists of project development activities in Italy and Bulgaria.

Earnings

2007 Compared with 2006

All Other and Corporate operations had earnings of $8.1 million in 2007, an increase of $7.9 million compared with earnings of $0.2 million for 2006. This improvement was largely due to an increase in interest income of $4.1 million (primarily intercompany interest). In the All Other category, Horizon LFG's earnings benefited from higher margins of $1.0 million in 2007 as compared to 2006, and Horizon Power's income from unconsolidated subsidiaries increased $0.9 million, also contributing to the increase in earnings. The Corporate and All Other categories also had an earnings benefit associated with a lower effective tax rate ($2.0 million).

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2006 Compared with 2005

All Other and Corporate operations experienced income of $0.2 million in 2006, which was $7.1 million greater than a loss of $6.9 million in 2005. The increase is due primarily to the non-recurrence of $4.5 million of impairment charges recorded in 2005. During 2005, Horizon Power recorded a $2.7 million impairment in the value of its 50% investment in ESNE. Management determined that there was a decline in the fair market value of ESNE that was other than temporary in nature given continuing high commodity prices for natural gas and the negative impact these prices had on operations. The Company also recorded a $1.8 million impairment of the gas-powered turbine mentioned above. This impairment was based on a review of current market prices for similar turbines. Also contributing to the increase were higher interest income ($4.7 million) during 2006, resulting primarily from the investment of proceeds from the sale of U.E. in July 2005, combined with higher average interest rates in 2006 versus 2005. These increases were partially offset by higher operating expenses ($1.3 million) and lower margins on landfill gas sales ($0.5 million).

INTEREST INCOME

Interest income was $7.9 million lower in 2007 as compared to 2006. As discussed in the Utility earnings section above, the main reason for this decrease was lower interest income of $7.4 million on a pension-related regulatory asset in accordance with the 2005 New York rate agreement. The New York division's 2005 rate agreement with the NYPSC allows the Company to accrue interest on a pension-related regulatory asset. The amount of the interest that can be accrued is reduced as the funded status of the pension plan improves. The fair market value of the pension plan assets exceeded the accumulated benefit obligation at September 30, 2007 resulting in a significant reduction in the interest accrual related to this regulatory asset in 2007.

Interest income was $3.2 million higher in 2006 as compared to 2005. As discussed in the earnings discussion by segment above, the main reasons for this increase were strong cash flow from operations, the investment of proceeds from the sale of U.E. in July 2005 and higher average annual interest rates. Additionally, interest income on a pension-related regulatory asset in accordance with the New York rate agreement increased by $0.5 million.

OTHER INCOME

Other income was $2.1 million higher in 2007 as compared to 2006. The increase is attributed to a death benefit gain on life insurance proceeds of $1.9 million recognized in the Corporate category.

Other income was $9.9 million lower in 2006 as compared to 2005. As discussed in the earnings discussion by segment above, the main reasons for this decrease included non-recurring gains recorded during 2005 in the Pipeline and Storage segment related to the sale of base gas ($2.6 million), and the disposition of insurance proceeds ($3.9 million) received in prior years for which a contingency was resolved.

INTEREST CHARGES

Although most of the variances in Interest Charges are discussed in the earnings discussion by segment above, the following is a summary on a consolidated basis:

Interest on long-term debt decreased $4.2 million in 2007 and $0.6 million in 2006. The decrease in 2007 was primarily the result of a lower average amount of long-term debt outstanding. In addition, the Company recognized a $1.9 million benefit to interest expense as a result of the discontinuance of hedge accounting for Empire's interest rate collar, as discussed above under Pipeline and Storage. The underlying long-term debt associated with this interest rate collar was repaid in December 2006 and the unrealized gain recorded in accumulated other comprehensive income associated with the interest rate collar was reclassified to interest expense during the quarter ended December 31, 2006.

Other interest charges were $0.1 million higher in 2007 and $3.1 million lower in 2006. The decrease in 2006 resulted primarily from the non-recurrence of $2.1 million of interest expense recorded by the Utility segment in 2005 and a lower average amount of short-term debt outstanding during 2006. The $2.1 million of interest expense recorded in 2005 related to an adjustment to a regulatory liability for previous over-collections of New York State gross receipts tax.

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CAPITAL RESOURCES AND LIQUIDITY

The primary sources and uses of cash during the last three years are summarized in the following condensed statement of cash flows:

Sources (Uses) of Cash

	Year Ended September 30		
	2007	2006 (Millions)	2005
Provided by Operating Activities	$ 394.2	$ 471.4	$ 317.3
Capital Expenditures	(276.7)	(294.2)	(219.5)
Investment in Partnership	(3.3)	—	—
Net Proceeds from Sale of Foreign Subsidiaries	232.1	—	111.6
Cash Held in Escrow	(58.2)	—	—
Net Proceeds from Sale of Oil and Gas Producing Properties	5.1	—	1.4
Other Investing Activities	(0.8)	(3.2)	3.2
Change in Short-Term Debt	—	—	(115.4)
Reduction of Long-Term Debt	(119.6)	(9.8)	(13.3)
Issuance of Common Stock	17.5	23.3	20.3
Dividends Paid on Common Stock	(100.6)	(98.2)	(94.1)
Dividends Paid to Minority Interest	—	—	(12.7)
Excess Tax Benefits Associated with Stock- Based Compensation Awards	13.7	6.5	—
Shares Repurchased under Repurchase Plan	(48.1)	(85.2)	—
Effect of Exchange Rates on Cash	(0.1)	1.4	1.3
Net Increase in Cash and Temporary Cash Investments	$ 55.2	$ 12.0	$ 0.1

OPERATING CASH FLOW

Internally generated cash from operating activities consists of net income available for common stock, adjusted for non-cash expenses, non-cash income and changes in operating assets and liabilities. Non-cash items include depreciation, depletion and amortization, impairment of oil and gas producing properties, impairment of investment in partnership, deferred income taxes, income or loss from unconsolidated subsidiaries net of cash distributions, minority interest in foreign subsidiaries and gain on sale of discontinued operations.

Cash provided by operating activities in the Utility and Pipeline and Storage segments may vary substantially from year to year because of the impact of rate cases. In the Utility segment, supplier refunds, over- or under-recovered purchased gas costs and weather may also significantly impact cash flow. The impact of weather on cash flow is tempered in the Utility segment's New York rate jurisdiction by its WNC and in the Pipeline and Storage segment by Supply Corporation's straight fixed-variable rate design.

Cash provided by operating activities in the Exploration and Production segment may vary from period to period as a result of changes in the commodity prices of natural gas and crude oil. The Company uses various derivative financial instruments, including price swap agreements, no cost collars and futures contracts in an attempt to manage this energy commodity price risk.

Net cash provided by operating activities totaled $394.2 million in 2007, a decrease of $77.2 million compared with the $471.4 million provided by operating activities in 2006. Higher working capital requirements in the Exploration and Production, Utility, and Pipeline and Storage segments were partially offset by lower working capital requirements in the Energy Marketing segment.

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INVESTING CASH FLOW

Expenditures for Long-Lived Assets

The Company's expenditures for long-lived assets associated with continuing operations totaled $250.9 million in 2007. The table below presents these expenditures:

	Year Ended September 30, 2007		
	Capital Expenditures	Investment in Partnership (Millions)	Total Expenditures For Long-Lived Assets
Utility	$ 54.2	$ —	$ 54.2
Pipeline and Storage	43.2	—	43.2
Exploration and Production	146.7	—	146.7
Timber	3.7	—	3.7
All Other and Corporate	(0.2)	3.3	3.1
Total Expenditures from Continuing Operations(1)	$ 247.6	$ 3.3	$ 250.9

(1) Excludes expenditures for long-lived assets associated with discontinued operations of $29.1 million.

Utility

The majority of the Utility capital expenditures were made for replacement of mains and main extensions, as well as for the replacement of service lines.

Pipeline and Storage

The majority of the Pipeline and Storage segment's capital expenditures were made for additions, improvements and replacements to this segment's transmission and gas storage systems. It also reflects $15.5 million of costs related to the Empire Connector project that were added to Construction Work in Progress during 2007. The Empire Connector project is discussed below under Estimated Capital Expenditures.

Exploration and Production

The Exploration and Production segment's capital expenditures were primarily well drilling and completion expenditures and included approximately $66.2 million for the Gulf Coast region ($65.7 million for the off-shore program in the Gulf of Mexico), $41.4 million for the West Coast region and $39.1 million for the Appalachian region. The significant amount spent in the Gulf Coast region is related to high commodity prices, which has improved the economics of investment in the area, plus projected royalty relief. These amounts included approximately $30.3 million spent to develop proved undeveloped reserves.

Timber

The majority of the Timber segment capital expenditures were for the construction of two new kilns that were placed into service during the quarter ended June 30, 2007, as well as construction of a lumber sorter for Highland's sawmill operations, which was placed into service in October 2007.

All Other and Corporate

The majority of the All Other and Corporate category expenditures for long-lived assets consisted of a $3.3 million capital contribution to Seneca Energy by Horizon Power, $1.65 million in each of the first and second quarters of fiscal 2007. Seneca Energy generates and sells electricity using methane gas obtained from landfills owned by outside parties. Seneca Energy is in the process of expanding its generating capacity from 11.2 megawatts to 17.6 megawatts. Horizon Power has funded its capital contributions with short-term borrowings.

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Estimated Capital Expenditures

The Company's estimated capital expenditures for the next three years are:

	Year Ended September 30		
	2008	2009	2010
		(Millions)	
Utility	$ 59.0	$ 57.0	$ 56.0
Pipeline and Storage	152.0	96.0	40.0
Exploration and Production(1)	154.0	146.0	143.0
Timber	1.0	—	—
	$ 366.0	$ 299.0	$ 239.0

(1) Includes estimated expenditures for the years ended September 30, 2008, 2009 and 2010 of approximately $33 million, $36 million and $27 million, respectively, to develop proved undeveloped reserves.

Estimated capital expenditures for the Utility segment in 2008 will be concentrated in the areas of main and service line improvements and replacements and, to a lesser extent, the purchase of new equipment.

Estimated capital expenditures for the Pipeline and Storage segment in 2008 includes $122.9 million for the Empire Connector project as discussed below. Other capital expenditures will be concentrated in the replacement of transmission and storage lines, reconditioning of storage wells and improvements of compressor stations.

The Company continues to explore various opportunities to expand its capabilities to transport gas to the East Coast, either through the Supply Corporation or Empire systems or in partnership with others. In October 2005, Empire filed an application with the FERC for the authority to build and operate the Empire Connector project to expand its natural gas pipeline operations to serve new markets in New York and elsewhere in the Northeast by extending the Empire Pipeline. The application also asked that Empire's existing business and facilities be brought under FERC jurisdiction, and that the FERC approve rates for Empire's existing and proposed services. The Empire Connector will provide an upstream supply link for the Millennium Pipeline, which began construction in June 2007, and will transport Canadian and other natural gas supplies to downstream customers. The Empire Connector is designed to move up to approximately 250 MDth of natural gas per day. On December 21, 2006, the FERC issued an order granting a Certificate of Public Convenience and Necessity authorizing the construction and operation of the Empire Connector and various other related pipeline projects by other unaffiliated companies, which has been accepted by Empire and the other applicants. In June 2007, Empire and KeySpan Gas East Corporation (KeySpan) executed a binding firm transportation service agreement for 150.75 MDth per day, obligating Empire to provide transportation service that will require construction of the Empire Connector project. Construction of the Empire Connector began in September 2007 and the planned in-service date is November 2008. Refer to the Rate and Regulatory Matters section that follows for further discussion of this matter. The forecasted expenditures for this project over the next two years are as follows: $122.9 million in 2008 and $34.4 million in 2009. These expenditures are included as Pipeline and Storage estimated capital expenditures in the table above. The total cost to the Company of the Empire Connector project is estimated at $177 million, after giving effect to sales tax exemptions worth approximately $3.7 million. The Company anticipates financing this project with cash on hand and/or through the use of the Company's lines of credit. As of September 30, 2007, the Company had incurred approximately $19.7 million in costs related to this project. Of this amount, $13.7 million, $2.0 million and $3.4 million were incurred during the years ended September 30, 2007, 2006 and 2005, respectively. During the quarter ended June 30, 2007, the Company reversed the reserve established for these costs, as discussed above under Results of Operations, following the execution of the KeySpan service agreement. As of September 30, 2007, all of the costs incurred to date related to this project have been capitalized as either Construction Work in Progress ($15.5 million) or Materials and Supplies Inventory ($4.2 million), as per the accounting guidance in the FERC's Uniform System of Accounts and SFAS 71.

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Supply Corporation continues to view its potential Tuscarora Extension project as an important link to Millennium and potential storage development in the Corning, New York area. This new pipeline, which would expand the Supply Corporation system from its Tuscarora storage field to the intersection of the proposed Millennium and Empire Connector pipelines, could be designed initially to transport up to approximately 130 MDth of natural gas per day. It may also provide Supply Corporation with the opportunity to increase the deliverability of the existing Tuscarora storage field. Supply Corporation is also developing a project to meet the results of an "Open Season" seeking customers for new capacity from the Rockies Express Project, Appalachian production, storage and other points to Leidy and to interconnections with Millennium and Empire at Corning. This new project (the "West to East Project") could include the Tuscarora Extension, or could be a second phase following the development of that project. The timeline of both of these projects depends on market development, and should the market mature, the Company anticipates financing the Tuscarora Extension with cash on hand and/or through the use of the Company's lines of credit. The capital cost of the West to East project could amount to $700 million, which would be financed by a combination of debt and equity. There have been no costs incurred by the Company related to either project as of September 30, 2007, and the forecasted expenditures for the Tuscarora Extension Project over the next three years are as follows: $0 in 2008, $34.0 million in 2009, and $15.0 million in 2010. These expenditures are included as Pipeline and Storage estimated capital expenditures in the table above. The Company has not yet forecast any expenditures for the West to East Project. The Company has not yet filed an application with the FERC for the authority to build either project.

Estimated capital expenditures in 2008 for the Exploration and Production segment include approximately $50.0 million for the Gulf Coast region ($48.0 million on the off-shore program in the Gulf of Mexico), $46.0 million for the West Coast region and $58.0 million for the Appalachian region.

Estimated capital expenditures in 2008 in the Timber segment will be concentrated on the purchase of new equipment, vehicles and improvements to facilities for this segment's lumber yard, sawmill and kiln operations.

The Company continuously evaluates capital expenditures and investments in corporations, partnerships and other business entities. The amounts are subject to modification for opportunities such as the acquisition of attractive oil and gas properties, timber or natural gas storage facilities and the expansion of natural gas transmission line capacities. While the majority of capital expenditures in the Utility segment are necessitated by the continued need for replacement and upgrading of mains and service lines, the magnitude of future capital expenditures or other investments in the Company's other business segments depends, to a large degree, upon market conditions.

FINANCING CASH FLOW

The Company did not have any outstanding short-term notes payable to banks or commercial paper at September 30, 2007. However, the Company continues to consider short-term debt (consisting of short-term notes payable to banks and commercial paper) an important source of cash for temporarily financing capital expenditures and investments in corporations and/or partnerships, gas-in-storage inventory, unrecovered purchased gas costs, margin calls on derivative financial instruments, exploration and development expenditures, repurchases of stock, and other working capital needs. Fluctuations in these items can have a significant impact on the amount and timing of short-term debt. As for bank loans, the Company maintains a number of individual uncommitted or discretionary lines of credit with certain financial institutions for general corporate purposes. Borrowings under these lines of credit are made at competitive market rates. These credit lines, which aggregate to $455.0 million, are revocable at the option of the financial institutions and are reviewed on an annual basis. The Company anticipates that these lines of credit will continue to be renewed, or replaced by similar lines. The total amount available to be issued under the Company's commercial paper program is $300.0 million. The commercial paper program is backed by a syndicated committed credit facility totaling $300.0 million that extends through September 30, 2010.

Under the Company's committed credit facility, the Company has agreed that its debt to capitalization ratio will not exceed .65 at the last day of any fiscal quarter from September 30, 2005 through September 30, 2010. At September 30, 2007, the Company's debt to capitalization ratio (as calculated under the facility) was .38. The constraints specified in the committed credit facility would permit an additional $2.02 billion in short-term

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and/or long-term debt to be outstanding (further limited by the indenture covenants discussed below) before the Company's debt to capitalization ratio would exceed .65. If a downgrade in any of the Company's credit ratings were to occur, access to the commercial paper markets might not be possible. However, the Company expects that it could borrow under its uncommitted bank lines of credit or rely upon other liquidity sources, including cash provided by operations.

Under the Company's existing indenture covenants, at September 30, 2007, the Company would have been permitted to issue up to a maximum of $1.4 billion in additional long-term unsecured indebtedness at then current market interest rates in addition to being able to issue new indebtedness to replace maturing debt. The Company's present liquidity position is believed to be adequate to satisfy known demands.

The Company's 1974 indenture, pursuant to which $399.0 million (or 40%) of the Company's long-term debt (as of September 30, 2007) was issued, contains a cross-default provision whereby the failure by the Company to perform certain obligations under other borrowing arrangements could trigger an obligation to repay the debt outstanding under the indenture. In particular, a repayment obligation could be triggered if the Company fails (i) to pay any scheduled principal or interest on any debt under any other indenture or agreement or (ii) to perform any other term in any other such indenture or agreement, and the effect of the failure causes, or would permit the holders of the debt to cause, the debt under such indenture or agreement to become due prior to its stated maturity, unless cured or waived.

The Company's $300.0 million committed credit facility also contains a cross-default provision whereby the failure by the Company or its significant subsidiaries to make payments under other borrowing arrangements, or the occurrence of certain events affecting those other borrowing arrangements, could trigger an obligation to repay any amounts outstanding under the committed credit facility. In particular, a repayment obligation could be triggered if (i) the Company or any of its significant subsidiaries fail to make a payment when due of any principal or interest on any other indebtedness aggregating $20.0 million or more or (ii) an event occurs that causes, or would permit the holders of any other indebtedness aggregating $20.0 million or more to cause, such indebtedness to become due prior to its stated maturity. As of September 30, 2007, the Company had no debt outstanding under the committed credit facility.

The Company's embedded cost of long-term debt was 6.4% at both September 30, 2007 and September 30, 2006. Refer to "Interest Rate Risk" in this Item for a more detailed breakdown of the Company's embedded cost of long-term debt.

The Company has an effective registration statement on file with the SEC under which it has available capacity to issue an additional $550.0 million of debt and equity securities under the Securities Act of 1933. The Company may sell all or a portion of these securities if warranted by market conditions and the Company's capital requirements. Any offer and sale of these securities will be made only by means of a prospectus meeting the requirements of the Securities Act of 1933 and the rules and regulations thereunder.

The amounts and timing of the issuance and sale of debt or equity securities will depend on market conditions, indenture requirements, regulatory authorizations and the capital requirements of the Company.

On April 30, 2007, the Company redeemed $96.3 million of 6.5% unsecured notes, plus accrued interest. These notes were redeemable by the Company at par at any time after September 15, 2006. On December 8, 2006, the Company repaid $22.8 million of Empire's secured debt. Such amount was classified as Current Portion of Long-Term Debt on the Company's Consolidated Balance Sheet at September 30, 2006.

On December 8, 2005, the Company's Board of Directors authorized the Company to implement a share repurchase program, whereby the Company may repurchase outstanding shares of common stock, up to an aggregate amount of 8 million shares in the open market or through privately negotiated transactions. As of September 30, 2007, the Company has repurchased 3,834,878 shares for $133.2 million under this program, including 1,308,328 shares for $48.1 million during fiscal 2007. These share repurchases were funded with cash provided by operating activities and/or through the use of the Company's lines of credit. In the future, it is expected that this share repurchase program will continue to be funded with cash provided by operating activities and/or through the use of the Company's lines of credit. It is expected that open market repurchases will continue from time to time depending on market conditions.

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OFF-BALANCE SHEET ARRANGEMENTS

The Company has entered into certain off-balance sheet financing arrangements. These financing arrangements are primarily operating and capital leases. The Company's consolidated subsidiaries have operating leases, the majority of which are with the Utility and the Pipeline and Storage segments, having a remaining lease commitment of approximately $35.5 million. These leases have been entered into for the use of buildings, vehicles, construction tools, meters and other items and are accounted for as operating leases. The Company's unconsolidated subsidiaries, which are accounted for under the equity method, have capital leases of electric generating equipment having a remaining lease commitment of approximately $4.8 million. The Company has guaranteed 50%, or $2.4 million, of these capital lease commitments.

CONTRACTUAL OBLIGATIONS

The following table summarizes the Company's expected future contractual cash obligations as of September 30, 2007, and the twelve-month periods over which they occur:

	Payments by Expected Maturity Dates						
	2008	2009	2010	2011	2012	Thereafter	Total
				(Millions)			
Long-Term Debt, including interest expense(1)	$ 259.8	$ 148.4	$ 45.5	$ 232.7	$ 171.8	$ 439.3	$ 1,297.5
Operating Lease Obligations	$ 6.7	$ 5.8	$ 4.4	$ 2.9	$ 2.6	$ 13.1	$ 35.5
Capital Lease Obligations	$ 0.9	$ 0.5	$ 0.4	$ 0.4	$ 0.2	$ —	$ 2.4
Purchase Obligations:							
Gas Purchase Contracts(2)	$ 718.1	$ 67.2	$ 7.1	$ 2.8	$ 2.8	$ 16.2	$ 814.2
Transportation and Storage Contracts	$ 48.4	$ 47.3	$ 43.7	$ 19.3	$ 6.0	$ 7.1	$ 171.8
Empire Connector Project Obligations(3)	$ 118.3	$ 0.6	$ —	$ —	$ —	$ —	$ 118.9
Other	$ 20.5	$ 9.6	$ 6.0	$ 4.2	$ 3.7	$ 14.2	$ 58.2

(1) Refer to Note E — Capitalization and Short-Term Borrowings, as well as the table under Interest Rate Risk in the Market Risk Sensitive Instruments section below, for the amounts excluding interest expense.

(2) Gas prices are variable based on the NYMEX prices adjusted for basis.

(3) The Empire Connector is scheduled to be placed in service by November 2008, at an estimated cost of $177 million. The Company has only committed itself to $118.9 million for the project at September 30, 2007.

The Company has made certain other guarantees on behalf of its subsidiaries. The guarantees relate primarily to: (i) obligations under derivative financial instruments, which are included on the consolidated balance sheet in accordance with SFAS 133 (see Item 7, MD&A under the heading "Critical Accounting Estimates — Accounting for Derivative Financial Instruments"); (ii) NFR obligations to purchase gas or to purchase gas transportation/storage services where the amounts due on those obligations each month are included on the consolidated balance sheet as a current liability; and (iii) other obligations which are reflected on the consolidated balance sheet. The Company believes that the likelihood it would be required to make payments under the guarantees is remote, and therefore has not included them in the table above.

OTHER MATTERS

In addition to the legal proceedings disclosed in Item 3 of this report, the Company is involved in other litigation and regulatory matters arising in the normal course of business. These other matters may include, for example, negligence claims and tax, regulatory or other governmental audits, inspections, investigations or other proceedings. These matters may involve state and federal taxes, safety, compliance with regulations, rate base, cost of service and purchased gas cost issues, among other things. While these normal-course matters could have a material effect on earnings and cash flows in the period in which they are resolved, they are not

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expected to change materially the Company's present liquidity position, nor to have a material adverse effect on the financial condition of the Company.

The Company has a tax-qualified, noncontributory defined-benefit retirement plan (Retirement Plan) that covers approximately 73% of the Company's employees. The Company has been making contributions to the Retirement Plan over the last several years and anticipates that it will continue making contributions to the Retirement Plan. During 2007, the Company contributed $24.9 million to the Retirement Plan. The Company anticipates that the annual contribution to the Retirement Plan in 2008 will be in the range of $15.0 million to $20.0 million. The Company expects that all subsidiaries having domestic employees covered by the Retirement Plan will make contributions to the Retirement Plan. The funding of such contributions will come from amounts collected in rates in the Utility and Pipeline and Storage segments or through short-term borrowings or through cash from operations.

The Company provides health care and life insurance benefits for a majority of its retired employees under a post-retirement benefit plan (Post-Retirement Plan). The Company has been making contributions to the Post-Retirement Plan over the last several years and anticipates that it will continue making contributions to the Post-Retirement Plan. During 2007, the Company contributed $42.3 million to the Post-Retirement Plan. The Company anticipates that the annual contribution to the Post-Retirement Plan in 2008 will be in the range of $25.0 million to $35.0 million. The funding of such contributions will come from amounts collected in rates in the Utility and Pipeline and Storage segments.

A capital loss carryover which existed at September 30, 2006, was fully utilized in 2007 in connection with the gain recognized on the sale of SECI.

MARKET RISK SENSITIVE INSTRUMENTS

Energy Commodity Price Risk

The Company, in its Exploration and Production segment, Energy Marketing segment, Pipeline and Storage segment, and All Other category, uses various derivative financial instruments (derivatives), including price swap agreements, no cost collars and futures contracts, as part of the Company's overall energy commodity price risk management strategy. Under this strategy, the Company manages a portion of the market risk associated with fluctuations in the price of natural gas and crude oil, thereby attempting to provide more stability to operating results. The Company has operating procedures in place that are administered by experienced management to monitor compliance with the Company's risk management policies. The derivatives are not held for trading purposes. The fair value of these derivatives, as shown below, represents the amount that the Company would receive from or pay to the respective counterparties at September 30, 2007 to terminate the derivatives. However, the tables below and the fair value that is disclosed do not consider the physical side of the natural gas and crude oil transactions that are related to the financial instruments.

The following tables disclose natural gas and crude oil price swap information by expected maturity dates for agreements in which the Company receives a fixed price in exchange for paying a variable price as quoted in various national natural gas publications or on the NYMEX. Notional amounts (quantities) are used to calculate the contractual payments to be exchanged under the contract. The weighted average variable prices represent the weighted average settlement prices by expected maturity date as of September 30, 2007. At September 30, 2007, the Company had not entered into any natural gas or crude oil price swap agreements extending beyond 2009.

Natural Gas Price Swap Agreements

	Expected Maturity Dates		
	2008	**2009**	**Total**
Notional Quantities (Equivalent Bcf)	12.2	1.0	13.2
Weighted Average Fixed Rate (per Mcf)	$ 8.15	$ 8.82	$ 8.20
Weighted Average Variable Rate (per Mcf)	$ 7.77	$ 9.08	$ 7.86

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Crude Oil Price Swap Agreements

	Expected Maturity Dates 2008	2009	Total
Notional Quantities (Equivalent bbls)	1,305,000	180,000	1,485,000
Weighted Average Fixed Rate (per bbl)	$ 57.72	$ 54.70	$ 57.35
Weighted Average Variable Rate (per bbl)	$ 78.69	$ 74.31	$ 78.16

At September 30, 2007, the Company would have received from its respective counterparties an aggregate of approximately $2.8 million to terminate the natural gas price swap agreements outstanding at that date. The Company would have had to pay an aggregate of approximately $11.2 million to its counterparties to terminate the crude oil price swap agreements outstanding at September 30, 2007.

At September 30, 2006, the Company had natural gas price swap agreements covering 7.4 Bcf at a weighted average fixed rate of $7.24 per Mcf. The Company also had crude oil price swap agreements covering 900,000 bbls at a weighted average fixed rate of $37.13 per bbl. The increase in natural gas price swap agreements from September 2006 to September 2007 is largely attributable to management's decision to utilize fewer collars and more swaps. This decision was as a result of market conditions being less conducive to using collars than they were in the prior year. The increase in crude oil price swap agreements is primarily due to an increased availability of counterparties willing to enter into new swap agreements with terms that match the delivery points of its West Coast crude oil production.

The following table discloses the notional quantities, the weighted average ceiling price and the weighted average floor price for the no cost collars used by the Company to manage natural gas price risk. The no cost collars provide for the Company to receive monthly payments from (or make payments to) other parties when a variable price falls below an established floor price (the Company receives payment from the counterparty) or exceeds an established ceiling price (the Company pays the counterparty). At September 30, 2007, the Company had not entered into any natural gas or crude oil no cost collars extending beyond 2008.

No Cost Collars

	Expected Maturity Date 2008
Natural Gas	
Notional Quantities (Equivalent Bcf)	1.4
Weighted Average Ceiling Price (per Mcf)	$ 16.45
Weighted Average Floor Price (per Mcf)	$ 8.83

At September 30, 2007, the Company would have received an aggregate of approximately $1.9 million to terminate the natural gas no cost collars outstanding at that date.

At September 30, 2006, the Company had natural gas no cost collars covering 7.1 Bcf at a weighted average floor price of $8.26 per Mcf and a weighted average ceiling price of $17.25 per Mcf. The Company also had crude oil no cost collars covering 180,000 bbls at a weighted average floor price of $70.00 per bbl and a weighted average ceiling price of $77.00 per bbl at September 30, 2006. The decrease in natural gas collars from September 2006 to September 2007 is due to management's decision to utilize fewer collars and more swaps. This is due to the market conditions discussed in the Swap Agreements section.

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The following table discloses the net contract volumes purchased (sold), weighted average contract prices and weighted average settlement prices by expected maturity date for futures contracts used to manage natural gas price risk. At September 30, 2007, the Company held no futures contracts with maturity dates extending beyond 2012.

Futures Contracts

	Expected Maturity Dates					
	2008	2009	2010	2011	2012	Total
Net Contract Volumes Purchased (Sold) (Equivalent Bcf)	2.9	(0.1)	—	—(1)	—(1)	2.8
Weighted Average Contract Price (per Mcf)	$ 9.08	$ 9.50	NA	$ 6.99	$ 8.68	$ 9.11
Weighted Average Settlement Price (per Mcf)	$ 8.94	$ 9.13	NA	$ 6.31	$ 9.00	$ 8.96

(1) The Energy Marketing segment has purchased 4 and 6 futures contracts (1 contract = 2,500 Dth) for 2011 and 2012, respectively.

At September 30, 2007, the Company would have received $2.2 million to terminate these futures contracts.

At September 30, 2006, the Company had futures contracts covering 7.0 Bcf (net long position) at a weighted average contract price of $9.67 per Mcf.

The decrease in net long positions at September 30, 2007 as compared to September 30, 2006 is attributed to fewer customers entering into fixed price sales commitments at September 30, 2007 as compared to September 30, 2006. Management believes this is due to the lack of a significant decrease in natural gas prices at the end of 2007 as compared to 2006, sufficient natural gas in storage throughout the United States, and forecasts for a mild winter. As a result, the Energy Marketing segment had purchased fewer futures contracts as of September 30, 2007 as compared to September 30, 2006 to hedge against a lower number of fixed price sales commitments.

The Company may be exposed to credit risk on some of the derivatives disclosed above. Credit risk relates to the risk of loss that the Company would incur as a result of nonperformance by counterparties pursuant to the terms of their contractual obligations. To mitigate such credit risk, management performs a credit check and then, on an ongoing basis, monitors counterparty credit exposure. Management has obtained guarantees from many of the parent companies of the respective counterparties to its derivatives. At September 30, 2007, the Company used nine counterparties for its over-the-counter derivatives. At September 30, 2007, no individual counterparty represented greater than 32% of total credit risk (measured as volumes hedged by an individual counterparty as a percentage of the Company's total volumes hedged). All of the counterparties (or the parent of the counterparty) were rated as investment grade entities at September 30, 2007.

Exchange Rate Risk

The Exploration and Production segment's investment in Canada was valued in Canadian dollars, and, as such, this investment was subject to currency exchange risk when the Canadian dollars are translated into U.S. dollars. This exchange rate risk to the Company's investment in Canada resulted in increases or decreases to the CTA, a component of Accumulated Other Comprehensive Income (Loss) on the Consolidated Balance Sheets. When the foreign currency increased in value in relation to the U.S. dollar, there was a positive adjustment to CTA. When the foreign currency decreased in value in relation to the U.S. dollar, there was a negative adjustment to CTA. In August 2007, the Exploration and Production segment's investment in Canada was sold, eliminating the Company's major foreign operations. Of the $232.1 million in net proceeds received, $58.0 million was placed in escrow (denominated in Canadian dollars) pending receipt of a tax clearance certificate from the Canadian government. To hedge against foreign currency exchange risk, the Company entered into a $58.0 million forward contract to sell Canadian dollars. At September 30, 2007, due to the increase in the strength of the Canadian dollar versus the U.S. dollar, the Company had a $2.7 million derivative

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liability related to the collar. The Company records gains or losses associated with this forward contract directly to the income statement.

Interest Rate Risk

On December 8, 2006, the Company repaid $22.8 million of Empire's secured debt. The interest costs of this secured debt were hedged by an interest rate collar. Since the hedged transaction was settled and there will be no future cash flows associated with the secured debt, hedge accounting for the interest rate collar was discontinued and the unrealized gain in accumulated other comprehensive income associated with the interest rate collar was reclassified to the Consolidated Statement of Income.

The following table presents the principal cash repayments and related weighted average interest rates by expected maturity date for the Company's long-term fixed rate debt as well as the other long-term debt of certain of the Company's subsidiaries. The interest rates for the variable rate debt are based on those in effect at September 30, 2007:

	Principal Amounts by Expected Maturity Dates						
	2008	2009	2010	2011	2012	Thereafter	Total
	(Dollars in millions)						
Long-Term Fixed Rate Debt	$ 200.0(1)	$ 100.0	$ —	$ 200.0	$ 150.0	$ 349.0	$ 999.0
Weighted Average Interest Rate Paid	6.3%	6.0%	—	7.5%	6.7%	5.9%	6.4%
Fair Value = $1,024.4							

(1) These notes have been classified as Current Portion of Long-Term Debt on the Company's Consolidated Balance Sheet.

RATE AND REGULATORY MATTERS

Utility Operation

Base rate adjustments in both the New York and Pennsylvania jurisdictions do not reflect the recovery of purchased gas costs. Such costs are recovered through operation of the purchased gas adjustment clauses of the appropriate regulatory authorities.

New York Jurisdiction

On August 27, 2004, Distribution Corporation commenced a rate case by filing proposed tariff amendments and supporting testimony requesting approval to increase its annual revenues beginning October 1, 2004. Various parties opposed the filing. On April 15, 2005, Distribution Corporation, the parties and others executed an agreement settling all outstanding issues. In an order issued July 22, 2005, the NYPSC approved the April 15, 2005 rate agreement, substantially as filed, for an effective date of August 1, 2005. The rate agreement provided for a rate increase of $21 million by means of the elimination of bill credits ($5.8 million) and an increase in base rates ($15.2 million). For the two-year term of the agreement and until new rates should go into effect, the return on equity level above which earnings must be shared with rate payers is 11.5%.

On January 29, 2007, Distribution Corporation commenced a rate case by filing proposed tariff amendments and supporting testimony requesting approval to increase its annual revenues by $52.0 million. Following standard procedure, the NYPSC suspended the proposed tariff amendments to enable its staff and intervenors to conduct a routine investigation and hold hearings. Distribution Corporation explained in the filing that its request for rate relief is necessitated by decreased revenues resulting from customer conservation efforts and increased customer uncollectibles, among other things. The rate filing also includes a proposal for an aggressive efficiency and conservation initiative with a revenue decoupling mechanism designed to render the Company indifferent to throughput reductions resulting from conservation. On September 20, 2007, the NYPSC issued an order approving, with modifications, the Company's conservation program for implementation on an accelerated basis. Associated ratemaking issues, however, were reserved for consideration in the rate case. On September 28, 2007, an administrative law judge assigned to the proceeding issued a

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recommended decision (RD) based on a review and analysis of the evidence presented in the case. The RD recommends a rate increase designed to provide additional annual revenues of $2.5 million, together with a bill surcharge that would collect up to $10.8 million to recover expenses arising from the conservation program. The recommended cost of equity, subject to updates, is 9.4%. The RD also recommends approval of the unopposed revenue decoupling mechanism. The NYPSC is not bound to accept the RD, and may accept, reject or modify the Company's filing. Assuming standard procedure, rates would become effective in late December 2007. The outcome of the proceeding cannot be ascertained at this time.

Pennsylvania Jurisdiction

On June 1, 2006, Distribution Corporation filed proposed tariff amendments with PaPUC to increase annual revenues by $25.9 million to cover increases in the cost of service to be effective July 30, 2006. The rate request was filed to address increased costs associated with Distribution Corporation's ongoing construction program as well as increases in operating costs, particularly uncollectible accounts. Following standard regulatory procedure, the PaPUC issued an order on July 20, 2006 instituting a rate proceeding and suspending the proposed tariff amendments until March 2, 2007. On October 2, 2006, the parties, including Distribution Corporation, Staff of the PaPUC and intervenors, executed an agreement (Settlement) proposing to settle all issues in the rate proceeding. The Settlement includes an increase in annual revenues of $14.3 million to non-gas revenues, an agreement not to file a rate case until January 28, 2008 at the earliest and an early implementation date. The Settlement was approved by the PaPUC at its meeting on November 30, 2006, and the new rates became effective January 1, 2007.

On June 8, 2006, the NTSB issued safety recommendations to Distribution Corporation, the PaPUC and certain other parties as a result of an investigation of a natural gas explosion that occurred on Distribution Corporation's system in Dubois, Pennsylvania in August 2004. The explosion destroyed a residence, resulting in the death of two people who lived there, and damaged a number of other houses in the immediate vicinity. Without admitting liability, Distribution Corporation settled all significant third-party claims against it related to the explosion.

The NTSB's safety recommendations to Distribution Corporation involved revisions to its butt-fusion procedures for joining plastic pipe, and revisions to its procedures for qualifying personnel who perform plastic fusions. Although not required by law to do so, Distribution Corporation implemented those recommendations. In December 2006, the NTSB classified its recommendations as "closed" after determining that Distribution Corporation took acceptable action with respect to the recommendations.

The NTSB's recommendation to the PaPUC was to require an analysis of the integrity of butt-fusion joints in Distribution Corporation's system and replacement of those joints that are determined to have unacceptable characteristics. Distribution Corporation has worked cooperatively with the Staff of the PaPUC to permit the PaPUC to undertake the analysis recommended by the NTSB.

In late November 2007, Distribution Corporation reached a Settlement Agreement with the Law Bureau Prosecutory Staff of the PaPUC (the "Law Bureau") regarding the explosion and the PaPUC's subsequent investigation. The Law Bureau and Distribution Corporation will jointly submit this Settlement Agreement to the PaPUC for approval. In the Settlement Agreement, Distribution Corporation agrees, without admitting liability, to pay a $50,000 fine and to fund an additional $30,000 of safety-related activities. Distribution Corporation also agrees to make various improvements to its butt-fusion procedures and to implement a program to review existing butt-fusions.

Pipeline and Storage

Supply Corporation currently does not have a rate case on file with the FERC. The rate settlement approved by the FERC on February 9, 2007 requires Supply Corporation to make a general rate filing to be effective December 1, 2011, and bars Supply Corporation from making a general rate filing before then, with some exceptions specified in the settlement.

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Empire currently does not have a rate case on file with the NYPSC. Among the issues resolved in connection with Empire's FERC application to build the Empire Connector are the rates and terms of service that will become applicable to all of Empire's business, effective upon Empire constructing and placing its new facilities into service (currently expected for November 2008). At that time, Empire will become an interstate pipeline subject to FERC regulation. The order described in the following paragraph requires Empire to make a filing at FERC within three years after the in-service date justifying Empire's existing recourse rates or proposing alternative rates.

The FERC issued on December 21, 2006 an order granting a Certificate of Public Convenience and Necessity authorizing the construction and operation of the Empire Connector and various other related pipeline projects by other unaffiliated companies. The Empire Certificate contains various environmental and other conditions. Empire has accepted that Certificate. Additional environmental permits from the U.S. Army Corps of Engineers and state environmental agencies have been received. Empire has also received, from all six upstate New York counties in which it would build the Empire Connector project, final approval of sales tax exemptions and temporary partial property tax abatements necessary to enable the Empire Connector to generate a fair return. In June 2007, Empire signed a firm transportation service agreement with KeySpan Gas East Corporation, under which Empire is obligated to provide transportation service that will require construction of this project. Construction began in September 2007 and is planned to be complete by November 1, 2008.

ENVIRONMENTAL MATTERS

The Company is subject to various federal, state and local laws and regulations relating to the protection of the environment. The Company has established procedures for the ongoing evaluation of its operations to identify potential environmental exposures and comply with regulatory policies and procedures. It is the Company's policy to accrue estimated environmental clean-up costs (investigation and remediation) when such amounts can reasonably be estimated and it is probable that the Company will be required to incur such costs. At September 30, 2007, the Company has estimated its remaining clean-up costs related to former manufactured gas plant sites and third party waste disposal sites will be in the range of $12.1 million to $15.8 million. The minimum estimated liability of $12.1 million has been recorded on the Consolidated Balance Sheet at September 30, 2007. The Company expects to recover its environmental clean-up costs from a combination of rate recovery and insurance proceeds. Other than discussed in Note H (referred to below), the Company is currently not aware of any material additional exposure to environmental liabilities. However, adverse changes in environmental regulations or other factors could impact the Company.

For further discussion refer to Item 8 at Note H — Commitments and Contingencies under the heading "Environmental Matters."

NEW ACCOUNTING PRONOUNCEMENTS

In June 2006, the FASB issued FIN 48. FIN 48 clarifies the accounting for income taxes by prescribing a minimum probability threshold that a tax position must meet before a financial statement benefit is recognized. The minimum threshold is defined in FIN 48 as a tax position that is more likely than not to be sustained upon examination by the applicable taxing authority, including resolution of any related appeals or litigation processes, based on the technical merits of the position. If a tax benefit meets this threshold, it is measured and recognized based on an analysis of the cumulative probability of the tax benefit being ultimately sustained. The cumulative effect of applying FIN 48 at adoption, if any, is reported as an adjustment to opening retained earnings for the year of adoption. FIN 48 is effective for the first quarter of the Company's 2008 fiscal year and it is expected that this pronouncement will not have a material effect on the Company's consolidated financial statements.

In September 2006, the FASB issued SFAS 157. SFAS 157 provides guidance for using fair value to measure assets and liabilities. The pronouncement serves to clarify the extent to which companies measure assets and liabilities at fair value, the information used to measure fair value, and the effect that fair-value measurements have on earnings. The Company is currently evaluating the impact that the adoption of SFAS 157 will have on its consolidated financial statements. SFAS 157 is to be applied whenever another standard requires or allows assets

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or liabilities to be measured at fair value. The pronouncement will be effective as of the Company's first quarter of fiscal 2009. The Company is currently evaluating the impact that the adoption of SFAS 157 will have on its consolidated financial statements.

In September 2006, the FASB issued SFAS 158, an amendment of SFAS 87, SFAS 88, SFAS 106, and SFAS 132R. SFAS 158 requires that companies recognize a net liability or asset to report the underfunded or overfunded status of their defined benefit pension and other post-retirement benefit plans on their balance sheets, as well as recognize changes in the funded status of a defined benefit post-retirement plan in the year in which the changes occur through comprehensive income. The pronouncement also specifies that a plan's assets and obligations that determine its funded status be measured as of the end of Company's fiscal year, with limited exceptions. Under SFAS 158, certain previously unrecognized actuarial gains and losses and previously unrecognized prior service costs for both the pension and other post-retirement benefit plans as well as a previously unrecognized transition obligation for the other post-retirement benefit plan are required to be recognized. These amounts were not required to be recorded on the Company's Consolidated Balance Sheet before the adoption of SFAS 158, but were instead amortized over a period of time. In accordance with SFAS 158, the Company has recognized the funded status of its benefit plans and implemented the disclosure requirements of SFAS 158 at September 30, 2007. The requirement to measure the plan assets and benefit obligations as of the Company's fiscal year-end date will be adopted by the Company by the end of fiscal 2009. Currently, the Company measures its plan assets and benefit obligations using a June 30th measurement date. At September 30, 2007, in order to recognize the funded status of its pension and post-retirement benefit plans in accordance with SFAS 158, the Company recorded additional liabilities or reduced assets by a cumulative amount of $78.7 million ($71.1 million net of deferred tax benefits recognized for the portion recorded as an increase to Accumulated Other Comprehensive Loss). Of the $71.1 million recognized, $61.9 million was recorded as an increase to Other Regulatory Assets in the Company's Utility and Pipeline and Storage segments, $12.5 million (net of deferred tax benefits of $7.6 million) was recorded as an increase to Accumulated Other Comprehensive Loss, and $3.3 million was recorded as an increase to Other Regulatory Liabilities in the Company's Utility segment. The Company has recorded amounts to Other Regulatory Assets or Other Regulatory Liabilities in the Utility and Pipeline and Storage segments in accordance with the provisions of SFAS 71. The Company, in those segments, has certain regulatory commission authorizations, which allow the Company to defer as a regulatory asset or liability the difference between pension and post-retirement benefit costs as calculated in accordance with SFAS 87 and SFAS 106 and what is collected in rates. Refer to Item 8 at Note G — Retirement Plan and Other Post-Retirement Benefits for further disclosures regarding the impact of SFAS 158 on the Company's consolidated financial statements.

In February 2007, the FASB issued SFAS 159. SFAS 159 permits entities to choose to measure many financial instruments and certain other items at fair value that are not otherwise required to be measured at fair value under GAAP. A company that elects the fair value option for an eligible item will be required to recognize in current earnings any changes in that item's fair value in reporting periods subsequent to the date of adoption. SFAS 159 will be effective as of the Company's first quarter of fiscal 2009. The Company is currently evaluating the impact, if any, that the adoption of SFAS 159 will have on its consolidated financial statements.

EFFECTS OF INFLATION

Although the rate of inflation has been relatively low over the past few years, the Company's operations remain sensitive to increases in the rate of inflation because of its capital spending and the regulated nature of a significant portion of its business.

SAFE HARBOR FOR FORWARD-LOOKING STATEMENTS

The Company is including the following cautionary statement in this Form 10-K to make applicable and take advantage of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 for any forward-looking statements made by, or on behalf of, the Company. Forward-looking statements include statements concerning plans, objectives, goals, projections, strategies, future events or performance, and underlying assumptions and other statements which are other than statements of historical facts. From time to time, the Company may publish or otherwise make available forward-looking statements of this nature. All such

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subsequent forward-looking statements, whether written or oral and whether made by or on behalf of the Company, are also expressly qualified by these cautionary statements. Certain statements contained in this report, including, without limitation, statements regarding future prospects, plans, performance and capital structure, anticipated capital expenditures, completion of construction projects, projections for pension and other post-retirement benefit obligations, impacts of the adoption of new accounting rules, and possible outcomes of litigation or regulatory proceedings, as well as statements that are identified by the use of the words "anticipates," "estimates," "expects," "forecasts," "intends," "plans," "predicts," "projects," "believes," "seeks," "will" and "may" and similar expressions, are "forward-looking" statements as defined in the Private Securities Litigation Reform Act of 1995 and accordingly involve risks and uncertainties which could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. The forward-looking statements contained herein are based on various assumptions, many of which are based, in turn, upon further assumptions. The Company's expectations, beliefs and projections are expressed in good faith and are believed by the Company to have a reasonable basis, including, without limitation, management's examination of historical operating trends, data contained in the Company's records and other data available from third parties, but there can be no assurance that management's expectations, beliefs or projections will result or be achieved or accomplished. In addition to other factors and matters discussed elsewhere herein, the following are important factors that, in the view of the Company, could cause actual results to differ materially from those discussed in the forward-looking statements:

1. Changes in economic conditions, including economic disruptions caused by terrorist activities, acts of war or major accidents;
2. Changes in demographic patterns and weather conditions, including the occurrence of severe weather such as hurricanes;
3. Changes in the availability and/or price of natural gas or oil and the effect of such changes on the accounting treatment of derivative financial instruments or the valuation of the Company's natural gas and oil reserves;
4. Uncertainty of oil and gas reserve estimates;
5. Ability to successfully identify, drill for and produce economically viable natural gas and oil reserves;
6. Significant changes from expectations in the Company's actual production levels for natural gas or oil;
7. Changes in the availability and/or price of derivative financial instruments;
8. Changes in the price differentials between various types of oil;
9. Inability to obtain new customers or retain existing ones;
10. Significant changes in competitive factors affecting the Company;
11. Changes in laws and regulations to which the Company is subject, including changes in tax, environmental, safety and employment laws and regulations;
12. Governmental/regulatory actions, initiatives and proceedings, including those involving acquisitions, financings, rate cases (which address, among other things, allowed rates of return, rate design and retained gas), affiliate relationships, industry structure, franchise renewal, and environmental/safety requirements;
13. Unanticipated impacts of restructuring initiatives in the natural gas and electric industries;
14. Significant changes from expectations in actual capital expenditures and operating expenses and unanticipated project delays or changes in project costs or plans;
15. The nature and projected profitability of pending and potential projects and other investments, and the ability to obtain necessary governmental approvals and permits;
16. Occurrences affecting the Company's ability to obtain funds from operations, from borrowings under our credit lines or other credit facilities or from issuances of other short-term notes or debt or equity securities to finance needed capital expenditures and other investments, including any downgrades in the Company's credit ratings;
17. Ability to successfully identify and finance acquisitions or other investments and ability to operate and integrate existing and any subsequently acquired business or properties;

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18. Impairments under the SEC's full cost ceiling test for natural gas and oil reserves;
19. Significant changes in tax rates or policies or in rates of inflation or interest;
20. Significant changes in the Company's relationship with its employees or contractors and the potential adverse effects if labor disputes, grievances or shortages were to occur;
21. Changes in accounting principles or the application of such principles to the Company;
22. The cost and effects of legal and administrative claims against the Company;
23. Changes in actuarial assumptions and the return on assets with respect to the Company's retirement plan and post-retirement benefit plans;
24. Increasing health care costs and the resulting effect on health insurance premiums and on the obligation to provide post-retirement benefits; or
25. Increasing costs of insurance, changes in coverage and the ability to obtain insurance.

The Company disclaims any obligation to update any forward-looking statements to reflect events or circumstances after the date hereof.

Item 7A ***Quantitative and Qualitative Disclosures About Market Risk***

Refer to the "Market Risk Sensitive Instruments" section in Item 7, MD&A.

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Item 8 ***Financial Statements and Supplementary Data***

Index to Financial Statements

All other schedules are omitted because they are not applicable or the required information is shown in the Consolidated Financial Statements or Notes thereto.

Supplementary Data

Supplementary data that is included in Note M — Quarterly Financial Data (unaudited) and Note O — Supplementary Information for Oil and Gas Producing Activities (unaudited), appears under this Item, and reference is made thereto.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of National Fuel Gas Company:

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of National Fuel Gas Company and its subsidiaries at September 30, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended September 30, 2007 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the accompanying index presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of September 30, 2007, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in "Management's Report on Internal Control Over Financial Reporting" appearing under Item 9A. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PRICEWATERHOUSECOOPERS LLP

Buffalo, New York
November 29, 2007

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NATIONAL FUEL GAS COMPANY

CONSOLIDATED STATEMENTS OF INCOME AND EARNINGS REINVESTED IN THE BUSINESS

	Year Ended September 30		
	2007	2006	2005
	(Thousands of dollars, except per common share amounts)		
INCOME			
Operating Revenues	$ 2,039,566	$ 2,239,675	$ 1,860,774
Operating Expenses			
Purchased Gas	1,018,081	1,267,562	959,827
Operation and Maintenance	396,408	395,289	388,094
Property, Franchise and Other Taxes	70,660	69,202	68,164
Depreciation, Depletion and Amortization	157,919	151,999	156,502
	1,643,068	1,884,052	1,572,587
Operating Income	396,498	355,623	288,187
Other Income (Expense):			
Income from Unconsolidated Subsidiaries	4,979	3,583	3,362
Impairment of Investment in Partnership	—	—	(4,158)
Other Income	4,936	2,825	12,744
Interest Income	1,550	9,409	6,236
Interest Expense on Long-Term Debt	(68,446)	(72,629)	(73,244)
Other Interest Expense	(6,029)	(5,952)	(9,069)
Income from Continuing Operations Before Income Taxes	333,488	292,859	224,058
Income Tax Expense	131,813	108,245	85,621
Income from Continuing Operations	201,675	184,614	138,437
Discontinued Operations:			
Income (Loss) from Operations, Net of Tax	15,479	(46,523)	25,277
Gain on Disposal, Net of Tax	120,301	—	25,774
Income (Loss) from Discontinued Operations, Net of Tax	135,780	(46,523)	51,051
Net Income Available for Common Stock	337,455	138,091	189,488
EARNINGS REINVESTED IN THE BUSINESS			
Balance at Beginning of Year	786,013	813,020	718,926
	1,123,468	951,111	908,414
Share Repurchases	38,196	66,269	—
Dividends on Common Stock	101,496	98,829	95,394
Balance at End of Year	$ 983,776	$ 786,013	$ 813,020
Earnings Per Common Share:			
Basic:			
Income from Continuing Operations	$ 2.43	$ 2.20	$ 1.66
Income (Loss) from Discontinued Operations	1.63	(0.56)	0.61
Net Income Available for Common Stock	$ 4.06	$ 1.64	$ 2.27
Diluted:			
Income from Continuing Operations	$ 2.37	$ 2.15	$ 1.63
Income (Loss) from Discontinued Operations	1.59	(0.54)	0.60
Net Income Available for Common Stock	$ 3.96	$ 1.61	$ 2.23
Weighted Average Common Shares Outstanding:			
Used in Basic Calculation	83,141,640	84,030,118	83,541,627
Used in Diluted Calculation	85,301,361	86,028,466	85,029,131

See Notes to Consolidated Financial Statements

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NATIONAL FUEL GAS COMPANY

CONSOLIDATED BALANCE SHEETS

	At September 30 2007	2006
	(Thousands of dollars)	
ASSETS		
Property, Plant and Equipment	$ 4,461,586	$ 4,703,040
Less — Accumulated Depreciation, Depletion and Amortization	1,583,181	1,825,314
	2,878,405	2,877,726
Current Assets		
Cash and Temporary Cash Investments	124,806	69,611
Cash Held in Escrow	61,964	—
Hedging Collateral Deposits	4,066	19,676
Receivables — Net of Allowance for Uncollectible Accounts of $28,654 and $31,427, Respectively	172,380	173,671
Unbilled Utility Revenue	20,682	25,538
Gas Stored Underground	66,195	59,461
Materials and Supplies — at average cost	35,669	36,693
Unrecovered Purchased Gas Costs	14,769	12,970
Other Current Assets	45,057	63,723
Deferred Income Taxes	8,550	23,402
	554,138	484,745
Other Assets		
Recoverable Future Taxes	83,954	79,511
Unamortized Debt Expense	12,070	15,492
Other Regulatory Assets	137,577	76,917
Deferred Charges	5,545	3,558
Other Investments	85,902	88,414
Investments in Unconsolidated Subsidiaries	18,256	11,590
Goodwill	5,476	5,476
Intangible Assets	28,836	31,498
Prepaid Pension and Post-Retirement Benefit Costs	61,006	64,125
Fair Value of Derivative Financial Instruments	9,188	11,305
Deferred Income Taxes	—	9,003
Other	8,059	4,388
	455,869	401,277
Total Assets	$ 3,888,412	$ 3,763,748
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Comprehensive Shareholders' Equity		
Common Stock, $1 Par Value		
Authorized — 200,000,000 Shares; Issued and Outstanding — 83,461,308 Shares and 83,402,670 Shares, Respectively	$ 83,461	$ 83,403
Paid In Capital	569,085	543,730
Earnings Reinvested in the Business	983,776	786,013
Total Common Shareholders' Equity Before Items Of Other Comprehensive Income (Loss)	1,636,322	1,413,146
Accumulated Other Comprehensive Income (Loss)	(6,203)	30,416
Total Comprehensive Shareholders' Equity	1,630,119	1,443,562
Long-Term Debt, Net of Current Portion	799,000	1,095,675
Total Capitalization	2,429,119	2,539,237
Current and Accrued Liabilities		
Notes Payable to Banks and Commercial Paper	—	—
Current Portion of Long-Term Debt	200,024	22,925
Accounts Payable	109,757	133,034
Amounts Payable to Customers	10,409	23,935
Dividends Payable	25,873	25,008
Interest Payable on Long-Term Debt	18,158	18,420
Customer Advances	22,863	29,417
Other Accruals and Current Liabilities	36,062	27,040
Fair Value of Derivative Financial Instruments	16,200	39,983
	439,346	319,762
Deferred Credits		
Deferred Income Taxes	575,356	544,502
Taxes Refundable to Customers	14,026	10,426
Unamortized Investment Tax Credit	5,392	6,094
Cost of Removal Regulatory Liability	91,226	85,076
Other Regulatory Liabilities	76,659	75,456
Post-Retirement Liabilities	70,555	32,918
Asset Retirement Obligations	75,939	77,392
Other Deferred Credits	110,794	72,885
	1,019,947	904,749
Commitments and Contingencies	—	—
Total Capitalization and Liabilities	$ 3,888,412	$ 3,763,748

See Notes to Consolidated Financial Statements

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NATIONAL FUEL GAS COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended September 30 2007	2006	2005
		(Thousands of dollars)	
Operating Activities			
Net Income Available for Common Stock	$ 337,455	$ 138,091	$ 189,488
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:			
Gain on Sale of Discontinued Operations	(159,873)	—	(27,386)
Impairment of Oil and Gas Producing Properties	—	104,739	—
Depreciation, Depletion and Amortization	170,803	179,615	193,144
Deferred Income Taxes	52,847	(5,230)	40,388
Income from Unconsolidated Subsidiaries, Net of Cash Distributions	(3,366)	1,067	(1,372)
Impairment of Investment in Partnership	—	—	4,158
Minority Interest in Foreign Subsidiaries	—	—	2,645
Excess Tax Benefits Associated with Stock-Based Compensation Awards	(13,689)	(6,515)	—
Other	16,399	4,829	7,390
Change in:			
Hedging Collateral Deposits	15,610	58,108	(69,172)
Receivables and Unbilled Utility Revenue	5,669	(12,343)	(25,828)
Gas Stored Underground and Materials and Supplies	(5,714)	1,679	1,934
Unrecovered Purchased Gas Costs	(1,799)	1,847	(7,285)
Prepayments and Other Current Assets	18,800	(39,572)	(42,409)
Accounts Payable	(26,002)	(23,144)	48,089
Amounts Payable to Customers	(13,526)	22,777	(1,996)
Customer Advances	(6,554)	4,946	3,971
Other Accruals and Current Liabilities	8,950	(17,754)	18,715
Other Assets	4,109	(22,700)	(13,461)
Other Liabilities	(5,922)	80,960	(3,667)
Net Cash Provided by Operating Activities	394,197	471,400	317,346
Investing Activities			
Capital Expenditures	(276,728)	(294,159)	(219,530)
Investment in Partnership	(3,300)	—	—
Net Proceeds from Sale of Foreign Subsidiaries	232,092	—	111,619
Cash Held in Escrow	(58,248)	—	—
Net Proceeds from Sale of Oil and Gas Producing Properties	5,137	13	1,349
Other	(725)	(3,230)	3,238
Net Cash Used in Investing Activities	(101,772)	(297,376)	(103,324)
Financing Activities			
Change in Notes Payable to Banks and Commercial Paper	—	—	(115,359)
Excess Tax Benefits Associated with Stock-Based Compensation Awards	13,689	6,515	—
Shares Repurchased under Repurchase Plan	(48,070)	(85,168)	—
Reduction of Long-Term Debt	(119,576)	(9,805)	(13,317)
Net Proceeds from Issuance of Common Stock	17,498	23,339	20,279
Dividends Paid on Common Stock	(100,632)	(98,266)	(94,159)
Dividends Paid to Minority Interest	—	—	(12,676)
Net Cash Used in Financing Activities	(237,091)	(163,385)	(215,232)
Effect of Exchange Rates on Cash	(139)	1,365	1,276
Net Increase in Cash and Temporary Cash Investments	55,195	12,004	66
Cash and Temporary Cash Investments At Beginning of Year	69,611	57,607	57,541
Cash and Temporary Cash Investments At End of Year	$ 124,806	$ 69,611	$ 57,607
Supplemental Disclosure of Cash Flow Information			
Cash Paid For:			
Interest	$ 75,987	$ 78,003	$ 84,455
Income Taxes	$ 97,961	$ 54,359	$ 83,542

See Notes to Consolidated Financial Statements

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NATIONAL FUEL GAS COMPANY

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended September 30		
	2007	2006	2005
		(Thousands of dollars)	
Net Income Available for Common Stock	$ 337,455	$ 138,091	$ 189,488
Other Comprehensive Income (Loss), Before Tax:			
Minimum Pension Liability Adjustment	—	165,914	(83,379)
Foreign Currency Translation Adjustment	7,874	7,408	14,286
Reclassification Adjustment for Realized Foreign Currency Translation Gain in Net Income	(42,658)	(716)	(37,793)
Unrealized Gain on Securities Available for Sale Arising During the Period	4,747	2,573	2,891
Reclassification Adjustment for Realized Gains On Securities Available for Sale in Net Income	—	—	(651)
Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	8,495	90,196	(206,847)
Reclassification Adjustment for Realized Loss on Derivative Financial Instruments in Net Income	5,106	91,743	97,689
Other Comprehensive Income (Loss), Before Tax	(16,436)	357,118	(213,804)
Income Tax Expense (Benefit) Related to Minimum Pension Liability Adjustment	—	58,070	(29,183)
Income Tax Expense Related to Foreign Currency Translation Adjustment	—	—	112
Reclassification Adjustment for Income Tax Expense on Foreign Currency Translation Adjustment in Net Income	—	—	(112)
Income Tax Expense Related to Unrealized Gain on Securities Available for Sale Arising During the Period	1,724	894	1,012
Reclassification Adjustment for Income Tax Expense on Realized Gains from Securities Available for Sale in Net Income	—	—	(228)
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	3,153	34,772	(79,059)
Reclassification Adjustment for Income Tax Benefit on Realized Loss on Derivative Financial Instruments In Net Income	2,824	35,338	36,507
Income Taxes — Net	7,701	129,074	(70,951)
Other Comprehensive Income (Loss)	(24,137)	228,044	(142,853)
Comprehensive Income	$ 313,318	$ 366,135	$ 46,635

See Notes to Consolidated Financial Statements

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NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note A — Summary of Significant Accounting Policies

Principles of Consolidation

The Company consolidates its majority owned entities. The equity method is used to account for minority owned entities. All significant intercompany balances and transactions are eliminated. The Company uses proportionate consolidation when accounting for drilling arrangements related to oil and gas producing properties accounted for under the full cost method of accounting.

The preparation of the consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Reclassification

Certain prior year amounts have been reclassified to conform with current year presentation.

Regulation

The Company is subject to regulation by certain state and federal authorities. The Company has accounting policies which conform to GAAP, as applied to regulated enterprises, and are in accordance with the accounting requirements and ratemaking practices of the regulatory authorities. Reference is made to Note C — Regulatory Matters for further discussion.

Revenues

The Company's Utility segment records revenue as bills are rendered, except that service supplied but not billed is reported as unbilled utility revenue and is included in operating revenues for the year in which service is furnished.

The Company's Energy Marketing segment records revenue as bills are rendered for service supplied on a calendar month basis.

The Company's Pipeline and Storage segment records revenue for natural gas transportation and storage services. Revenue from reservation charges on firm contracted capacity is recognized through equal monthly charges over the contract period regardless of the amount of gas that is transported or stored. Commodity charges on firm contracted capacity and interruptible contracts are recognized as revenue when physical deliveries of natural gas are made at the agreed upon delivery point or when gas is injected or withdrawn from the storage field. The point of delivery into the pipeline or injection or withdrawal from storage is the point at which ownership and risk of loss transfers to the buyer of such transportation and storage services.

The Company's Timber segment records revenue on lumber and log sales as products are shipped, which is the point at which ownership and risk of loss transfers to the buyer of lumber products or logs.

The Company's Exploration and Production segment records revenue based on entitlement, which means that revenue is recorded based on the actual amount of gas or oil that is delivered to a pipeline and the Company's ownership interest in the producing well. If a production imbalance occurs between what was supposed to be delivered to a pipeline and what was actually produced and delivered, the Company accrues the difference as an imbalance.

Allowance for Uncollectible Accounts

The allowance for uncollectible accounts is the Company's best estimate of the amount of probable credit losses in the existing accounts receivable. The allowance is determined based on historical experience, the age

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and other specific information about customer accounts. Account balances are charged off against the allowance twelve months after the account is final billed or when it is anticipated that the receivable will not be recovered.

Regulatory Mechanisms

The Company's rate schedules in the Utility segment contain clauses that permit adjustment of revenues to reflect price changes from the cost of purchased gas included in base rates. Differences between amounts currently recoverable and actual adjustment clause revenues, as well as other price changes and pipeline and storage company refunds not yet includable in adjustment clause rates, are deferred and accounted for as either unrecovered purchased gas costs or amounts payable to customers. Such amounts are generally recovered from (or passed back to) customers during the following fiscal year.

Estimated refund liabilities to ratepayers represent management's current estimate of such refunds. Reference is made to Note C — Regulatory Matters for further discussion.

The impact of weather on revenues in the Utility segment's New York rate jurisdiction is tempered by a WNC, which covers the eight-month period from October through May. The WNC is designed to adjust the rates of retail customers to reflect the impact of deviations from normal weather. Weather that is more than 2.2% warmer than normal results in a surcharge being added to customers' current bills, while weather that is more than 2.2% colder than normal results in a refund being credited to customers' current bills. Since the Utility segment's Pennsylvania rate jurisdiction does not have a WNC, weather variations have a direct impact on the Pennsylvania rate jurisdiction's revenues.

In the Pipeline and Storage segment, the allowed rates that Supply Corporation bills its customers are based on a straight fixed-variable rate design, which allows recovery of all fixed costs in fixed monthly reservation charges. The allowed rates that Empire bills its customers are based on a modified-fixed variable rate design, which allows recovery of most fixed costs in fixed monthly reservation charges. To distinguish between the two rate designs, the modified fixed-variable rate design recovers return on equity and income taxes through variable charges whereas straight fixed-variable recovers all fixed costs, including return on equity and income taxes, through its monthly reservation charge. Because of the difference in rate design, changes in throughput due to weather variations do not have a significant impact on Supply Corporation's revenues but may have a significant impact on Empire's revenues.

Property, Plant and Equipment

The principal assets of the Utility and Pipeline and Storage segments, consisting primarily of gas plant in service, are recorded at the historical cost when originally devoted to service in the regulated businesses, as required by regulatory authorities.

In the Company's Exploration and Production segment, oil and gas property acquisition, exploration and development costs are capitalized under the full cost method of accounting. Under this methodology, all costs associated with property acquisition, exploration and development activities are capitalized, including internal costs directly identified with acquisition, exploration and development activities. The internal costs that are capitalized do not include any costs related to production, general corporate overhead, or similar activities. The Company does not recognize any gain or loss on the sale or other disposition of oil and gas properties unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves of oil and gas attributable to a cost center.

Capitalized costs include costs related to unproved properties, which are excluded from amortization until proved reserves are found or it is determined that the unproved properties are impaired. All costs related to unproved properties are reviewed quarterly to determine if impairment has occurred. The amount of any impairment is transferred to the pool of capitalized costs being amortized.

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NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Capitalized costs are subject to the SEC full cost ceiling test. The ceiling test, which is performed each quarter, determines a limit, or ceiling, on a country-by-country basis on the amount of property acquisition, exploration and development costs that can be capitalized. The ceiling under this test represents (a) the present value of estimated future net cash flows, excluding future cash outflows associated with settling asset retirement obligations that have been accrued on the balance sheet, using a discount factor of 10%, which is computed by applying current market prices of oil and gas (as adjusted for hedging) to estimated future production of proved oil and gas reserves as of the date of the latest balance sheet, less estimated future expenditures, plus (b) the cost of unevaluated properties not being depleted, less (c) income tax effects related to the differences between the book and tax basis of the properties. If capitalized costs, net of accumulated depreciation, depletion and amortization and related deferred income taxes, exceed the ceiling at the end of any quarter, a permanent impairment is required to be charged to earnings in that quarter. In adjusting estimated future net cash flows for hedging under the ceiling test at September 30, 2007, 2006, and 2005, estimated future net cash flows were increased by $2.2 million, increased by $4.7 million, and decreased by $175.3 million, respectively. The Company's capitalized costs exceeded the full cost ceiling for the Company's Canadian properties at June 30, 2006 and September 30, 2006. As such, the Company recognized pre-tax impairments of $62.4 million at June 30, 2006 and $42.3 million at September 30, 2006. These impairment charges are included in loss from discontinued operations for 2006 due to the sale of SECI during 2007.

Maintenance and repairs of property and replacements of minor items of property are charged directly to maintenance expense. The original cost of the regulated subsidiaries' property, plant and equipment retired, and the cost of removal less salvage, are charged to accumulated depreciation.

Depreciation, Depletion and Amortization

For oil and gas properties, depreciation, depletion and amortization is computed based on quantities produced in relation to proved reserves using the units of production method. The cost of unproved oil and gas properties is excluded from this computation. For timber properties, depletion, determined on a property by property basis, is charged to operations based on the actual amount of timber cut in relation to the total amount of recoverable timber. For all other property, plant and equipment, depreciation, depletion and amortization is computed using the straight-line method in amounts sufficient to recover costs over the estimated service lives of property in service. The following is a summary of depreciable plant by segment:

	As of September 30	
	2007	2006
	(Thousands)	
Utility	$ 1,539,808	$ 1,493,991
Pipeline and Storage	976,316	962,831
Exploration and Production(1)	1,577,745	1,899,777
Energy Marketing	1,199	1,123
Timber	119,237	116,281
All Other and Corporate	32,806	33,338
	$ 4,247,111	$ 4,507,341

(1) Fiscal 2006 includes the depreciable plant of SECI discontinued operations of $469,810.

NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Average depreciation, depletion and amortization rates are as follows:

	Year Ended September 30		
	2007	2006	2005
Utility	2.8%	2.8%	2.8%
Pipeline and Storage	3.5%	4.0%	4.1%
Exploration and Production, per Mcfe(1)	$ 1.94	$ 2.00	$ 1.74
Energy Marketing	2.8%	4.8%	7.6%
Timber	4.0%	5.6%	6.2%
All Other and Corporate	4.6%	4.1%	4.3%

(1) Amounts include depletion of oil and gas producing properties as well as depreciation of fixed assets. As disclosed in Note O — Supplementary Information for Oil and Gas Producing Properties, depletion of oil and gas producing properties amounted to $1.92, $1.98 and $1.72 per Mcfe of production in 2007, 2006 and 2005, respectively. Depletion of oil and gas producing properties in the United States amounted to $1.97, $1.74 and $1.58 per Mcfe of production in 2007, 2006 and 2005, respectively. Depletion of oil and gas producing properties in Canada amounted to $1.67, $2.95 and $2.36 per Mcfe of production in 2007, 2006 and 2005, respectively.

Goodwill

The Company has recognized goodwill of $5.5 million as of September 30, 2007 and 2006 on its consolidated balance sheet related to the Company's acquisition of Empire in 2003. The Company accounts for goodwill in accordance with SFAS 142, which requires the Company to test goodwill for impairment annually. At September 30, 2007 and 2006, the fair value of Empire was greater than its book value. As such, the goodwill was considered not impaired.

Financial Instruments

Unrealized gains or losses from the Company's investments in an equity mutual fund and the stock of an insurance company (securities available for sale) are recorded as a component of accumulated other comprehensive income (loss). Reference is made to Note F — Financial Instruments for further discussion.

The Company uses a variety of derivative financial instruments to manage a portion of the market risk associated with fluctuations in the price of natural gas and crude oil. These instruments include price swap agreements, no cost collars and futures contracts. The Company accounts for these instruments as either cash flow hedges or fair value hedges. In both cases, the fair value of the instrument is recognized on the Consolidated Balance Sheets as either an asset or a liability labeled fair value of derivative financial instruments. Fair value represents the amount the Company would receive or pay to terminate these instruments.

For effective cash flow hedges, the offset to the asset or liability that is recorded is a gain or loss recorded in accumulated other comprehensive income (loss) on the Consolidated Balance Sheets. The gain or loss recorded in accumulated other comprehensive income (loss) remains there until the hedged transaction occurs, at which point the gains or losses are reclassified to operating revenues, purchased gas expense or interest expense on the Consolidated Statements of Income. Any ineffectiveness associated with the cash flow hedges is recorded in the Consolidated Statements of Income. In December 2006, the Company repaid $22.8 million of Empire's secured debt. The interest costs of this secured debt were hedged by an interest rate collar. Since the hedged transaction was settled and there will be no future cash flows associated with the secured debt, hedge accounting for the interest rate collar was discontinued and the unrealized gain of $1.9 million in accumulated other comprehensive income associated with the interest rate collar was reclassified to the Consolidated Statement of Income. The Company did not experience any material ineffectiveness with regard to its cash flow hedges during 2006.

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NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

At September 30, 2005, it was determined that certain derivative financial instruments no longer qualified as effective cash flow hedges due to anticipated delays in oil and gas production volumes caused by Hurricane Rita. These volumes were originally forecast to be produced in the first quarter of 2006. As such, at September 30, 2005, the Company reclassified $5.1 million in accumulated losses on such derivative financial instruments from accumulated other comprehensive income (loss) on the Consolidated Balance Sheet to other revenues on the Consolidated Statement of Income. For fair value hedges, the offset to the asset or liability that is recorded is a gain or loss recorded to operating revenues or purchased gas expense on the Consolidated Statements of Income. However, in the case of fair value hedges, the Company also records an asset or liability on the Consolidated Balance Sheets representing the change in fair value of the asset or firm commitment that is being hedged (see Other Current Assets section in this footnote). The offset to this asset or liability is a gain or loss recorded to operating revenues or purchased gas expense on the Consolidated Statements of Income as well. If the fair value hedge is effective, the gain or loss from the derivative financial instrument is offset by the gain or loss that arises from the change in fair value of the asset or firm commitment that is being hedged. The Company did not experience any material ineffectiveness with regard to its fair value hedges during 2007, 2006 or 2005.

Accumulated Other Comprehensive Income (Loss)

The components of Accumulated Other Comprehensive Income (Loss) are as follows:

	Year Ended September 30	
	2007	2006
	(Thousands)	
Funded Position of the Pension and Other Post-Retirement Benefit Plans Adjustment	$ (12,482)(1)	$ —
Cumulative Foreign Currency Translation Adjustment	(83)	34,701
Net Unrealized Loss on Derivative Financial Instruments	(3,886)	(11,510)
Net Unrealized Gain on Securities Available for Sale	10,248	7,225
Accumulated Other Comprehensive Income (Loss)	$ (6,203)	$ 30,416

(1) In accordance with the transition recognition provisions of SFAS 158, the adjustment to recognize the funded positions of the Pension and Other Post-retirement Benefit Plans are shown as an adjustment to the ending balance of accumulated other comprehensive income (loss). The adjustment is not shown as other comprehensive income (loss) in the Consolidated Statements of Comprehensive Income.

At September 30, 2007, it is estimated that of the $3.9 million net unrealized loss on derivative financial instruments shown in the table above, $2.4 million will be reclassified into the Consolidated Statement of Income during 2008. The remaining unrealized loss on derivative financial instruments of $1.5 million will be reclassified into the Consolidated Statement of Income in subsequent years. As disclosed in Note F — Financial Instruments, the Company's derivative financial instruments extend out to 2012.

Gas Stored Underground — Current

In the Utility segment, gas stored underground — current in the amount of $33.0 million is carried at lower of cost or market, on a LIFO method. Based upon the average price of spot market gas purchased in September 2007, including transportation costs, the current cost of replacing this inventory of gas stored underground — current exceeded the amount stated on a LIFO basis by approximately $129.3 million at September 30, 2007. All other gas stored underground — current, which is in the Energy Marketing segment, is carried at lower of cost or market on an average cost method.

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NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Purchased Timber Rights

In the Timber segment, the Company purchases the right to harvest timber from land owned by other parties. These rights, which extend from several months to several years, are purchased to ensure a consistent supply of timber for the Company's sawmill and kiln operations. The historical value of timber rights expected to be harvested during the following year are included in Materials and Supplies on the Consolidated Balance Sheets while the historical value of timber rights expected to be harvested beyond one year are included in Other Assets on the Consolidated Balance Sheets. The components of the Company's purchased timber rights are as follows:

	Year Ended September 30	
	2007	2006
	(Thousands)	
Materials and Supplies	$ 8,925	$ 13,174
Other Assets	5,641	3,218
	$ 14,566	$ 16,392

Unamortized Debt Expense

Costs associated with the issuance of debt by the Company are deferred and amortized over the lives of the related debt. Costs associated with the reacquisition of debt related to rate-regulated subsidiaries are deferred and amortized over the remaining life of the issue or the life of the replacement debt in order to match regulatory treatment.

Foreign Currency Translation

The functional currency for the Company's foreign operations is the local currency of the country where the operations are located. Asset and liability accounts are translated at the rate of exchange on the balance sheet date. Revenues and expenses are translated at the average exchange rate during the period. Foreign currency translation adjustments are recorded as a component of accumulated other comprehensive income (loss). With the sale of SECI on August 31, 2007, the Company has eliminated its major foreign operation. While the Company is in the process of winding up or selling certain power development projects in Europe, the investment in such projects is not significant and the Company does not expect to have any significant foreign currency translation adjustments in the future.

Income Taxes

The Company and its domestic subsidiaries file a consolidated federal income tax return. Investment tax credit, prior to its repeal in 1986, was deferred and is being amortized over the estimated useful lives of the related property, as required by regulatory authorities having jurisdiction.

Consolidated Statements of Cash Flows

For purposes of the Consolidated Statements of Cash Flows, the Company considers all highly liquid debt instruments purchased with a maturity of three months or less to be cash equivalents.

Hedging Collateral Account

Cash held in margin accounts serves as collateral for open positions on exchange-traded futures contracts, exchange-traded options and over-the-counter swaps and collars.

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NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Cash Held in Escrow

On August 31, 2007, the Company received approximately $232.1 million of proceeds from the sale of SECI, of which $58.0 million was placed in escrow pending receipt of a tax clearance certificate from the Canadian government. The escrow account is a Canadian dollar denominated account. On a U.S. dollar basis, the value of this account was $62.0 million at September 30, 2007.

Other Current Assets

Other Current Assets consist of prepayments in the amounts of $14.1 million and $12.0 million at September 30, 2007 and 2006, respectively, prepaid property and other taxes of $14.1 million and $13.7 million at September 30, 2007 and 2006, respectively, federal income taxes receivable in the amounts of $8.7 million and $7.5 million at September 30, 2007 and 2006, respectively, state income taxes receivable in the amounts of zero and $7.4 million at September 30, 2007 and 2006, respectively, and fair values of firm commitments in the amounts of $8.2 million and $23.1 million at September 30, 2007 and 2006, respectively.

Earnings Per Common Share

Basic earnings per common share is computed by dividing income available for common stock by the weighted average number of common shares outstanding for the period. Diluted earnings per common share reflects the potential dilution that could occur if securities or other contracts to issue common stock were exercised or converted into common stock. The only potentially dilutive securities the Company has outstanding are stock options and stock-settled SARs. The diluted weighted average shares outstanding shown on the Consolidated Statements of Income reflects the potential dilution as a result of these stock options and stock-settled SARs as determined using the Treasury Stock Method. Stock options and stock-settled SARs that are antidilutive are excluded from the calculation of diluted earnings per common share. For 2007, no stock options or stock-settled SARs were excluded as being antidilutive. For 2006, 119,241 stock options were excluded as being antidilutive. There were no stock-settled SARs excluded as being antidilutive for 2006. There were no stock options or stock-settled SARs excluded as being antidilutive for 2005.

Share Repurchases

The Company considers all shares repurchased as cancelled shares restored to the status of authorized but unissued shares, in accordance with New Jersey law. The repurchases are accounted for on the date the share repurchase is settled as an adjustment to common stock (at par value) with the excess repurchase price allocated between paid in capital and retained earnings. Refer to Note E — Capitalization and Short-Term Borrowings for further discussion of the share repurchase program.

Stock-Based Compensation

The Company has various stock option and stock award plans which provide or provided for the issuance of one or more of the following to key employees: incentive stock options, nonqualified stock options, stock-settled SARs, restricted stock, performance units or performance shares. Stock options and stock-settled SARs under all plans have exercise prices equal to the average market price of Company common stock on the date of grant, and generally no stock option or stock-settled SAR is exercisable less than one year or more than ten years after the date of each grant. Restricted stock is subject to restrictions on vesting and transferability. Restricted stock awards entitle the participants to full dividend and voting rights. Certificates for shares of restricted stock awarded under the Company’s stock option and stock award plans are held by the Company during the periods in which the restrictions on vesting are effective. Restrictions on restricted stock awards generally lapse ratably over a period of not more than ten years after the date of each grant.

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Prior to October 1, 2005, the Company accounted for its stock-based compensation under the recognition and measurement principles of APB 25 and related interpretations. Under that method, no compensation expense was recognized for options granted under the Company's stock option and stock award plans. The Company did record, in accordance with APB 25, compensation expense for the market value of restricted stock on the date of the award over the periods during which the vesting restrictions existed.

Effective October 1, 2005, the Company adopted SFAS 123R, which requires the measurement and recognition of compensation cost at fair value for all share-based payments, including stock options and stock-settled SARs. The Company has chosen to use the modified version of prospective application, as allowed by SFAS 123R. Using the modified prospective application, the Company recorded compensation cost for the portion of awards granted prior to October 1, 2005 for which the requisite service had not been rendered and recognized such compensation cost as the requisite service was rendered on or after October 1, 2005. Such compensation expense is based on the grant-date fair value of the awards as calculated for the Company's disclosure using a Binomial option-pricing model under SFAS 123. Any new awards, modifications to awards, repurchases of awards, or cancellations of awards subsequent to September 30, 2005 will follow the provisions of SFAS 123R, with compensation expense being calculated using the Black-Scholes-Merton closed form model. The Company has chosen the Black-Scholes-Merton closed form model since it is easier to administer than the Binomial option-pricing model. Furthermore, since the Company does not have complex stock-based compensation awards, it does not believe that compensation expense would be materially different under either model. There were 448,000, 317,000 and 700,000 stock options granted during the years ended September 30, 2007, 2006 and 2005, respectively. The Company granted 50,000 stock-settled SARs during the year ended September 30, 2007. There were no stock-settled SARs granted during the years ended September 30, 2006 and 2005. The accounting treatment for such stock-settled SARs is the same under SFAS 123R as the accounting for stock options under SFAS 123R. The Company also granted 25,000 and 16,000 restricted share awards (non-vested stock as defined by SFAS 123R) during the years ended September 30, 2007 and 2006, respectively. There were no restricted share awards granted during the year ended September 30, 2005. Stock-based compensation expense for the years ended September 30, 2007, 2006 and 2005 was approximately $3,727,000, $1,705,000, and $517,000, respectively. Stock-based compensation expense is included in operation and maintenance expense on the Consolidated Statement of Income. The total income tax benefit related to stock-based compensation expense during the years ended September 30, 2007, 2006 and 2005 was approximately $1,488,000, $653,000 and $206,000, respectively. There were no capitalized stock-based compensation costs during the years ended September 30, 2007 and 2006.

Prior to the adoption of SFAS 123R, the Company followed the nominal vesting period approach under the disclosure requirements of SFAS 123 for determining the vesting period for awards with retirement-eligible provisions, which recognized stock-based compensation expense over the nominal vesting period. As a result of the adoption of SFAS 123R, the Company currently applies the non-substantive vesting period approach for determining the vesting period of such awards. Under this approach, the retention of the award is not contingent on providing subsequent service and the vesting period would begin at the grant date and end at the retirement-eligible date. For the year ended September 30, 2007, the amount of compensation expense recognized by the Company using the non-substantive vesting approach was $280,000 ($182,000 net of tax) less than if the nominal vesting period approach had been used. For the year ended September 30, 2006, the Company recognized an additional $442,000 ($288,000 net of tax) of stock-based compensation expense by applying the non-substantive vesting approach as opposed to the nominal vesting period approach. For the year ended September 30, 2005, stock-based compensation expense would have been $4,282,000 ($2,752,000 net of tax) for pro forma recognition purposes had the non-substantive vesting period approach been used. Pro forma stock-based compensation expense following the nominal vesting period approach is shown in the table below.

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NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The following table illustrates the effect on net income and earnings per share of the Company had the Company applied the fair value recognition provisions of SFAS 123 relating to stock-based employee compensation for the year ended September 30, 2005:

	Year Ended September 30, 2005 (Thousands, except per share amounts)
Net Income, Available for Common Stock, As Reported	$ 189,488
Add: Stock-Based Employee Compensation Expense Included in Reported Net Income, Net of Tax(1)	336
Deduct: Total Stock-Based Employee Compensation Expense Determined Under Fair Value Based Methods for all Awards, Net of Related Tax Effects	(2,782)
Pro Forma Net Income Available for Common Stock	$ 187,042
Earnings Per Common Share:	
Basic — As Reported	$ 2.27
Basic — Pro Forma	$ 2.24
Diluted — As Reported	$ 2.23
Diluted — Pro Forma	$ 2.20

(1) Stock-based compensation expense in 2005 represented compensation expense related to restricted stock awards. The pre-tax expense was $517,000 for the year ended September 30, 2005.

Stock Options

The total intrinsic value of stock options exercised during the years ended September 30, 2007, 2006 and 2005 totaled approximately $38.7 million, $30.9 million, and $19.8 million, respectively. For 2007, 2006 and 2005, the amount of cash received by the Company from the exercise of such stock options was approximately $26.0 million, $30.1 million, and $24.8 million, respectively.

The Company realizes tax benefits related to the exercise of stock options on a calendar year basis as opposed to a fiscal year basis. As such, for stock options exercised during the quarters ended December 31, 2006, 2005, and 2004, the Company realized a tax benefit of $3.2 million, $0.9 million, and $1.1 million, respectively. For stock options exercised during the period of January 1, 2007 through September 30, 2007, the Company will realize a tax benefit of approximately $12.0 million in the quarter ended December 31, 2007. For stock options exercised during the period of January 1, 2006 through September 30, 2006, the Company realized a tax benefit of approximately $11.4 million in the quarter ended December 31, 2006. For stock options exercised during the period of January 1, 2005 through September 30, 2005, the Company realized a tax benefit of approximately $6.3 million in the quarter ended December 31, 2005. The weighted average grant date fair value of options granted in 2007, 2006 and 2005 is $7.27 per share, $6.68 per share, and $4.59 per share, respectively. For the years ended September 30, 2007, 2006 and 2005, 327,501, 89,665 and 1,375,105 stock options became fully vested, respectively. The total fair value of these stock options was approximately $2.1 million, $0.4 million and $6.2 million, respectively, for the years ended September 30, 2007, 2006 and 2005. As of September 30, 2007, unrecognized compensation expense related to stock options totaled approximately $0.9 million, which will be recognized over a weighted average period of 10.6 months. For a summary of transactions during 2007 involving option shares for all plans, refer to Note E — Capitalization and Short-Term Borrowings.

The fair value of options at the date of grant was estimated using a Binomial option-pricing model for options granted prior to October 1, 2005 and the Black-Scholes-Merton closed form model for options granted

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

after September 30, 2005. The following weighted average assumptions were used in estimating the fair value of options at the date of grant:

	Year Ended September 30		
	2007	2006	2005
Risk Free Interest Rate	4.46%	5.08%	4.46%
Expected Life (Years)	7.0	7.0	7.0
Expected Volatility	17.73%	17.71%	17.76%
Expected Dividend Yield (Quarterly)	0.76%	0.83%	1.00%

The risk-free interest rate is based on the yield of a Treasury Note with a remaining term commensurate with the expected term of the option. The expected life and expected volatility are based on historical experience.

For grants prior to October 1, 2005, the Company used a forfeiture rate of 13.6% for calculating stock-based compensation expense related to stock options and this rate is based on the Company's historical experience of forfeitures on unvested stock option grants. For grants during the years ended September 30, 2007 and 2006, it was assumed that there would be no forfeitures, based on the vesting term and the number of grantees.

Stock-settled SARs

There were no stock-settled SARs exercised during the years ended September 30, 2007, 2006 and 2005 as none of the stock-settled SARs granted have vested. The weighted average grant date fair value of stock-settled SARs granted in 2007 is $7.81 per share. There were no stock-settled SARs granted during 2006 or 2005. For the years ended September 30, 2007, 2006 and 2005, there were no stock-settled SARs that became fully vested. As of September 30, 2007, unrecognized compensation expense related to stock-settled SARs totaled approximately $0.3 million, which will be recognized over a weighted average period of 1.4 years. For a summary of transactions during 2007 involving stock-settled SARs for all plans, refer to Note E — Capitalization and Short-Term Borrowings.

The fair value of stock-settled SARs at the date of grant was estimated using the Black-Scholes-Merton closed form model. The following weighted average assumptions were used in estimating the fair value of options at the date of grant:

	Year Ended September 30, 2007
Risk Free Interest Rate	4.53%
Expected Life (Years)	7.0
Expected Volatility	17.55%
Expected Dividend Yield (Quarterly)	0.73%

The risk-free interest rate is based on the yield of a Treasury Note with a remaining term commensurate with the expected term of the option. The expected life and expected volatility are based on historical experience.

For grants during the year ended September 30, 2007, it was assumed that there would be no forfeitures, based on the vesting term and the number of grantees.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Restricted Share Awards

The weighted average fair value of restricted share awards granted in 2007 and 2006 is $40.18 per share and $34.94 per share, respectively. There were no restricted share awards granted during 2005. As of September 30, 2007, unrecognized compensation expense related to restricted share awards totaled approximately $1.0 million, which will be recognized over a weighted average period of 1.7 years. For a summary of transactions during 2007 involving restricted share awards, refer to Note E — Capitalization and Short-Term Borrowings.

During 2006, a modification was made to a restricted share award involving one employee. The modification accelerated the vesting date of 4,000 shares from December 7, 2006 to July 1, 2006. The incremental compensation expense, totaling approximately $32,000, was included with the total stock-based compensation expense for the year ended September 30, 2006.

New Accounting Pronouncements

In June 2006, the FASB issued FIN 48, "Accounting for Uncertainty in Income Taxes." FIN 48 clarifies the accounting for income taxes by prescribing a minimum probability threshold that a tax position must meet before a financial statement benefit is recognized. The minimum threshold is defined in FIN 48 as a tax position that is more likely than not to be sustained upon examination by the applicable taxing authority, including resolution of any related appeals or litigation processes, based on the technical merits of the position. If a tax benefit meets this threshold, it is measured and recognized based on an analysis of the cumulative probability of the tax benefit being ultimately sustained. The cumulative effect of applying FIN 48 at adoption, if any, is reported as an adjustment to opening retained earnings for the year of adoption. FIN 48 is effective for the first quarter of the Company's 2008 fiscal year and it is expected that this pronouncement will not have a material effect on the Company's consolidated financial statements.

In September 2006, the FASB issued SFAS 157, "Fair Value Measurements." SFAS 157 provides guidance for using fair value to measure assets and liabilities. The pronouncement serves to clarify the extent to which companies measure assets and liabilities at fair value, the information used to measure fair value, and the effect that fair-value measurements have on earnings. SFAS 157 is to be applied whenever another standard requires or allows assets or liabilities to be measured at fair value. The pronouncement is effective as of the Company's first quarter of fiscal 2009. The Company is currently evaluating the impact that the adoption of SFAS 157 will have on its consolidated financial statements.

In September 2006, the FASB also issued SFAS 158, "Employer's Accounting for Defined Benefit Pension and Other Postretirement Plans" (an amendment of SFAS 87, SFAS 88, SFAS 106, and SFAS 132R). SFAS 158 requires that companies recognize a net liability or asset to report the underfunded or overfunded status of their defined benefit pension and other post-retirement benefit plans on their balance sheets, as well as recognize changes in the funded status of a defined benefit post-retirement plan in the year in which the changes occur through comprehensive income. The pronouncement also specifies that a plan's assets and obligations that determine its funded status be measured as of the end of the Company's fiscal year, with limited exceptions. In accordance with SFAS 158, the Company has recognized the funded status of its benefit plans and implemented the disclosure requirements of SFAS 158 at September 30, 2007. The requirement to measure the plan assets and benefit obligations as of the Company's fiscal year-end date will be adopted by the Company by the end of fiscal 2009. Currently, the Company measures its plan assets and benefit obligations using a June 30th measurement date. At September 30, 2007, in order to recognize the funded status of its pension and post-retirement benefit plans in accordance with SFAS 158, the Company recorded additional liabilities or reduced assets by a cumulative amount of $78.7 million ($71.1 million net of deferred tax benefits recognized for the portion recorded as an increase to Accumulated Other Comprehensive Loss). Of the $71.1 million recognized, $61.9 million was recorded as an increase to Other Regulatory Assets in the Company's Utility and Pipeline and Storage segments, $12.5 million (net of deferred tax benefits of $7.6 million) was recorded as an increase to Accumulated Other Comprehensive Loss, and $3.3 million was recorded as an increase to Other Regulatory

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Liabilities in the Company's Utility segment. The Company has recorded amounts to Other Regulatory Assets or Other Regulatory Liabilities in the Utility and Pipeline and Storage segments in accordance with the provisions of SFAS 71. The Company, in those segments, has certain regulatory commission authorizations, which allow the Company to defer as a regulatory asset or liability the difference between pension and post-retirement benefit costs as calculated in accordance with SFAS 87 and SFAS 106 and what is collected in rates. Refer to Note G — Retirement Plan and Other Post-Retirement Benefits for further disclosures regarding the impact of SFAS 158 on the Company's consolidated financial statements.

In February 2007, the FASB issued SFAS 159, "The Fair Value Option for Financial Assets and Financial Liabilities — Including an Amendment of SFAS 115." SFAS 159 permits entities to choose to measure many financial instruments and certain other items at fair value that are not otherwise required to be measured at fair value under GAAP. A company that elects the fair value option for an eligible item will be required to recognize in current earnings any changes in that item's fair value in reporting periods subsequent to the date of adoption. SFAS 159 is effective as of the Company's first quarter of fiscal 2009. The Company is currently evaluating the impact, if any, that the adoption of SFAS 159 will have on its consolidated financial statements.

Note B — Asset Retirement Obligations

The Company accounts for asset retirement obligations in accordance with the provisions of SFAS 143. SFAS 143 requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, the entity capitalizes the estimated cost of retiring the asset as part of the carrying amount of the related long-lived asset. Over time, the liability is adjusted to its present value each period and the capitalized cost is depreciated over the useful life of the related asset.

As previously disclosed, the Company follows the full cost method of accounting for its exploration and production costs. Upon the adoption of SFAS 143 on October 1, 2002, the Company recorded an asset retirement obligation representing plugging and abandonment costs associated with the Exploration and Production segment's crude oil and natural gas wells and capitalized such costs in property, plant and equipment (i.e. the full cost pool). Prior to the adoption of SFAS 143, plugging and abandonment costs were accounted for solely through the Company's units-of-production depletion calculation. An estimate of such costs was added to the depletion base, which also included capitalized costs in the full cost pool and estimated future expenditures to be incurred in developing proved reserves. With the adoption of SFAS 143, plugging and abandonment costs are already included in capitalized costs and the units-of-production depletion calculation has been modified to exclude from the depletion base any estimate of future plugging and abandonment costs that are already recorded in the full cost pool.

The full cost method of accounting provides a limit to the amount of costs that can be capitalized in the full cost pool. This limit is referred to as the full cost ceiling. Prior to the adoption of SFAS 143, in calculating the full cost ceiling, the Company reduced the future net cash flows from proved oil and gas reserves by the estimated plugging and abandonment costs. Such future net cash flows would then be compared to capitalized costs in the full cost pool, with any excess capitalized costs being expensed. With the adoption of SFAS 143, since the full cost pool now includes an amount associated with plugging and abandoning the wells, the calculation of the full cost ceiling has been changed so that future net cash flows from proved oil and gas reserves are no longer reduced by the estimated plugging and abandonment costs.

On September 30, 2006, the Company adopted FIN 47, an interpretation of SFAS 143. FIN 47 provides clarification of the term "conditional asset retirement obligation" as used in SFAS 143, defined as a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the Company. Under this standard, if the fair value of a conditional asset retirement obligation can be reasonably estimated, a company must record a liability and a corresponding asset for the conditional asset retirement obligation representing the present value of that obligation at the date the obligation was incurred. FIN 47 also serves to clarify when a company

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

would have sufficient information to reasonably estimate the fair value of a conditional asset retirement obligation.

Upon the adoption of FIN 47, the Company recorded future asset retirement obligations associated with the plugging and abandonment of natural gas storage wells in the Pipeline and Storage segment and the removal of asbestos and asbestos-containing material in various facilities in the Utility and Pipeline and Storage segments. The Company also identified asset retirement obligations for certain costs connected with the retirement of distribution mains and services pipeline systems in the Utility segment and with the transmission mains and other components in the pipeline systems in the Pipeline and Storage segment. These retirement costs within the distribution and transmission systems are primarily for the capping and purging of pipe, which are generally abandoned in place when retired, as well as for the clean-up of PCB contamination associated with the removal of certain pipe.

As a result of the implementation of FIN 47 as of September 30, 2006, the Company recorded additional asset retirement obligations of $23.2 million and corresponding long-lived plant assets, net of accumulated depreciation, of $3.5 million. These assets will be depreciated over their respective remaining depreciable life. The remaining $19.7 million represents the cumulative accretion and depreciation of the asset retirement obligations that would have been recognized if this interpretation had been in effect at the inception of the obligations. Of this amount, the Company recorded an increase to regulatory assets of $9.0 million and a reduction to cost of removal regulatory liability of $10.7 million. The cost of removal regulatory liability represents amounts collected from customers through depreciation expense in the Company’s Utility and Pipeline and Storage segments. These removal costs are not a legal retirement obligation in accordance with SFAS 143. Rather, they represent a regulatory liability. However, SFAS 143 requires that such costs of removal be reclassified from accumulated depreciation to other regulatory liabilities. At September 30, 2007 and 2006, the costs of removal reclassified to other regulatory liabilities amounted to $91.2 million and $85.1 million, respectively.

A reconciliation of the Company’s asset retirement obligation calculated in accordance with SFAS 143 is shown below ($000s):

	Year Ended September 30		
	2007	2006	2005
		(Thousands)	
Balance at Beginning of Year	$ 77,392	$ 41,411	$ 32,292
Additions — Adoption of FIN 47	—	23,234	—
Liabilities Incurred and Revisions of Estimates	(932)	11,244	8,343
Liabilities Settled	(6,108)	(1,303)	(1,938)
Accretion Expense	5,394	2,671	2,448
Exchange Rate Impact	193	135	266
Balance at End of Year	$ 75,939	$ 77,392	$ 41,411

Pursuant to FIN 47, the financial statements for periods prior to September 30, 2006 have not been restated. If FIN 47 had been in effect, the Company would have recorded additional asset retirement obligations of $21.9 million at October 1, 2005.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Note C — Regulatory Matters

Regulatory Assets and Liabilities

The Company has recorded the following regulatory assets and liabilities:

	At September 30	
	2007	2006
	(Thousands)	
Regulatory Assets(1):		
Pension and Post-Retirement Benefit Costs(2) (Note G)	$ 98,787	$ 47,368
Recoverable Future Taxes (Note D)	83,954	79,511
Environmental Site Remediation Costs(2) (Note H)	20,738	12,937
Unrecovered Purchased Gas Costs (See Regulatory Mechanisms in Note A)	14,769	12,970
Unamortized Debt Expense (Note A)	8,470	8,399
Asset Retirement Obligations(2) (Note B)	8,315	9,018
Recoverable Worker Compensation Expense(2)	4,445	3,691
Other(2)	5,292	3,903
Total Regulatory Assets	244,770	177,797
Regulatory Liabilities:		
Cost of Removal Regulatory Liability (Note B)	91,226	85,076
New York Rate Settlements(3)	27,964	40,881
Pension and Post-Retirement Benefit Costs(3) (Note G)	21,676	13,063
Tax Benefit on Medicare Part D Subsidy(3)	19,147	13,791
Taxes Refundable to Customers (Note D)	14,026	10,426
Amounts Payable to Customers (See Regulatory Mechanisms in Note A)	10,409	23,935
Deferred Insurance Proceeds(3)	7,422	7,516
Other(3)	450	205
Total Regulatory Liabilities	192,320	194,893
Net Regulatory Position	$ 52,450	$ (17,096)

(1) The Company recovers the cost of its regulatory assets but, with the exception of Unrecovered Purchased Gas Costs, does not earn a return on them.

(2) Included in Other Regulatory Assets on the Consolidated Balance Sheets.

(3) Included in Other Regulatory Liabilities on the Consolidated Balance Sheets.

If for any reason the Company ceases to meet the criteria for application of regulatory accounting treatment for all or part of its operations, the regulatory assets and liabilities related to those portions ceasing to meet such criteria would be eliminated from the balance sheet and included in income of the period in which the discontinuance of regulatory accounting treatment occurs. Such amounts would be classified as an extraordinary item.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

New York Rate Settlements

With respect to utility services provided in New York, the Company has entered into rate settlements approved by the NYPSC. The rate settlements have given rise to several significant liabilities, which are described as follows:

Gross Receipts Tax Over-Collections — In accordance with NYPSC policies, Distribution Corporation deferred the difference between the revenues it collects under a New York State gross receipts tax surcharge and its actual New York State income tax expense. Distribution Corporation's cumulative gross receipts tax revenues exceeded its New York State income tax expense, resulting in a regulatory liability at September 30, 2007 and 2006 of $6.7 million and $19.8 million, respectively. Under the terms of its 2005 rate agreement, Distribution Corporation has been passing back that regulatory liability to rate payers since August 1, 2005. Further, the gross receipts tax surcharge that gave rise to the regulatory liability was eliminated from Distribution Corporation's tariff (New York State income taxes are now recovered as a component of base rates).

Cost Mitigation Reserve ("CMR") — The CMR is a regulatory liability that can be used to offset certain expense items specified in Distribution Corporation's rate settlements. The source of the CMR is principally the accumulation of certain refunds from upstream pipeline companies. During 2005, under the terms of the 2005 rate agreement, Distribution Corporation transferred the remaining balance in a generic restructuring reserve (which had been established in a prior rate settlement) and the balances it had accumulated under various earnings sharing mechanisms to the CMR. The balance in the CMR at September 30, 2007 and 2006 amounted to $7.4 million and $7.6 million, respectively.

Other — The 2005 agreement also established a reserve to fund area development projects. The balance in the area development projects reserve at September 30, 2007 and 2006 amounted to $3.6 million and $3.9 million, respectively (Distribution Corporation established the reserve at September 30, 2005 by transferring $3.8 million from the CMR discussed above). Various other regulatory liabilities have also been created through the New York rate settlements and amounted to $10.3 million and $9.6 million at September 30, 2007 and 2006, respectively.

Tax Benefit on Medicare Part D Subsidy

The Company has established a regulatory liability for the tax benefit it will receive under the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (the Act). The Act provides a federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare Part D. In the Company's Utility and Pipeline and Storage segments, the ratepayer funds the Company's post-retirement benefit plans. As such, any tax benefit received under the Act must be flowed-through to the ratepayer. Refer to Note G — Retirement Plan and Other Post-Retirement Benefits for further discussion of the Act and its impact on the Company.

Deferred Insurance Proceeds

In 2006, the Company, in its Utility and Pipeline and Storage segments, received $7.5 million in environmental insurance settlement proceeds. Such proceeds have been deferred as a regulatory liability to be applied against any future environmental claims that may be incurred. The proceeds have been classified as a regulatory liability in recognition of the fact that ratepayers funded the premiums on the former insurance policies. Deferred insurance proceeds amounted to $7.4 million at September 30, 2007.

Recoverable Worker Compensation Expense

The Company has established a liability in its Utility segment in accordance with the provisions of SFAS 112 for future worker compensation liabilities. Such amounts have been deferred as a regulatory asset because the Company is allowed to recover worker compensation expense in rates.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Note D — Income Taxes

The components of federal, state and foreign income taxes included in the Consolidated Statements of Income are as follows:

	Year Ended September 30		
	2007	2006	2005
		(Thousands)	
Current Income Taxes —			
Federal	$ 99,608	$ 65,593	$ 45,571
State	21,700	13,511	14,413
Foreign	22	2,212	4,104
Deferred Income Taxes —			
Federal	39,340	19,111	27,412
State	10,751	9,024	2,280
Foreign	2,756	(33,365)	10,120
	174,177	76,086	103,900
Deferred Investment Tax Credit	(697)	(697)	(697)
Total Income Taxes	$ 173,480	$ 75,389	$ 103,203
Presented as Follows:			
Other Income	$ (697)	$ (697)	$ (697)
Income Tax Expense — Continuing Operations	131,813	108,245	85,621
Discontinued Operations —			
Income From Operations	2,792	(32,159)	16,667
Gain on Disposal	39,572	—	1,612
Total Income Taxes	$ 173,480	$ 75,389	$ 103,203

The U.S. and foreign components of income (loss) before income taxes are as follows:

	Year Ended September 30		
	2007	2006	2005
		(Thousands)	
U.S.	$ 496,074	$ 293,887	$ 223,113
Foreign	14,861	(80,407)	69,578
	$ 510,935	$ 213,480	$ 292,691

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Total income taxes as reported differ from the amounts that were computed by applying the federal income tax rate to income before income taxes. The following is a reconciliation of this difference:

	Year Ended September 30		
	2007	2006	2005
		(Thousands)	
Income Tax Expense, Computed at U.S. Federal Statutory Rate of 35%	$ 178,827	$ 74,718	$ 102,442
Increase in Taxes Resulting from:			
State Income Taxes	21,093	14,648	10,850
Foreign Tax Differential	(20,980)	(3,718)	(4,845)
Reversal of Capital Loss Valuation Allowance	—	(2,877)	—
Miscellaneous	(5,460)	(7,382)	(5,244)
Total Income Taxes	$ 173,480	$ 75,389	$ 103,203

The foreign tax differential amount shown above for 2007 includes tax effects relating to the gain on disposition of a foreign subsidiary. Also, the foreign tax differential amount shown above for 2006 includes a $5.1 million deferred tax benefit relating to additional future tax deductions forecasted in Canada and the amount for 2005 includes tax effects relating to the disposition of a foreign subsidiary. The miscellaneous amount shown above for 2006 includes a net reversal of $3.2 million relating to a tax contingency reserve.

Significant components of the Company's deferred tax liabilities and assets are as follows:

	At September 30	
	2007	2006
	(Thousands)	
Deferred Tax Liabilities:		
Property, Plant and Equipment	$ 612,648	$ 569,677
Other	61,616	37,865
Total Deferred Tax Liabilities	674,264	607,542
Deferred Tax Assets:		
Other	(107,458)	(95,445)
Total Deferred Tax Assets	(107,458)	(95,445)
Total Net Deferred Income Taxes	$ 566,806	$ 512,097
Presented as Follows:		
Net Deferred Tax Asset — Current	$ (8,550)	$ (23,402)
Net Deferred Tax Asset — Non-Current	—	(9,003)
Net Deferred Tax Liability — Non-Current	575,356	544,502
Total Net Deferred Income Taxes	$ 566,806	$ 512,097

Regulatory liabilities representing the reduction of previously recorded deferred income taxes associated with rate-regulated activities that are expected to be refundable to customers amounted to $14.0 million and $10.4 million at September 30, 2007 and 2006, respectively. Also, regulatory assets representing future amounts collectible from customers, corresponding to additional deferred income taxes not previously recorded because of prior ratemaking practices, amounted to $84.0 million and $79.5 million at September 30, 2007 and 2006, respectively.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Note E — Capitalization and Short-Term Borrowings

Summary of Changes in Common Stock Equity

	Common Stock		Paid In Capital	Earnings Reinvested in the Business	Accumulated Other Comprehensive Income (Loss)
	Shares	Amount			
	(Thousands, except per share amounts)				
Balance at September 30, 2004	82,990	$ 82,990	$ 506,560	$ 718,926	$ (54,775)
Net Income Available for Common Stock				189,488	
Dividends Declared on Common Stock ($1.14 Per Share)				(95,394)	
Other Comprehensive Loss, Net of Tax					(142,853)
Cancellation of Shares	(2)	(2)	(52)		
Common Stock Issued Under Stock and Benefit Plans(1)	1,369	1,369	23,326		
Balance at September 30, 2005	84,357	84,357	529,834	813,020	(197,628)
Net Income Available for Common Stock				138,091	
Dividends Declared on Common Stock ($1.18 Per Share)				(98,829)	
Other Comprehensive Income, Net of Tax					228,044
Share-Based Payment Expense(2)			1,705		
Common Stock Issued Under Stock and Benefit Plans(1)	1,572	1,572	28,564		
Share Repurchases	(2,526)	(2,526)	(16,373)	(66,269)	
Balance at September 30, 2006	83,403	83,403	543,730	786,013	30,416
Net Income Available for Common Stock				337,455	
Dividends Declared on Common Stock ($1.22 Per Share)				(101,496)	
Other Comprehensive Loss, Net of Tax					(24,137)
Adjustment to Recognize the Funded Position of the Pension and Other Post-Retirement Benefit Plans					(12,482)
Share-Based Payment Expense(2)			3,727		
Common Stock Issued Under Stock and Benefit Plans(1)	1,367	1,367	30,193		
Share Repurchases	(1,309)	(1,309)	(8,565)	(38,196)	
Balance at September 30, 2007	83,461	$ 83,461	$ 569,085	$ 983,776(3)	$ (6,203)

(1) Paid in Capital includes tax benefits of $13.7 million, $6.5 million and $3.7 million for September 30, 2007, 2006 and 2005, respectively, associated with the exercise of stock options.

(2) As of October 1, 2005, Paid in Capital includes compensation costs associated with stock option, stock-settled SARs and/or restricted stock awards, in accordance with SFAS 123R. The expense is included within Net Income Available For Common Stock, net of tax benefits.

(3) The availability of consolidated earnings reinvested in the business for dividends payable in cash is limited under terms of the indentures covering long-term debt. At September 30, 2007, $880.6 million of accumulated earnings was free of such limitations.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Common Stock

The Company has various plans which allow shareholders, employees and others to purchase shares of the Company common stock. The National Fuel Gas Company Direct Stock Purchase and Dividend Reinvestment Plan allows shareholders to reinvest cash dividends and make cash investments in the Company's common stock and provides investors the opportunity to acquire shares of the Company common stock without the payment of any brokerage commissions in connection with such acquisitions. The 401(k) Plans allow employees the opportunity to invest in the Company common stock, in addition to a variety of other investment alternatives. Generally, at the discretion of the Company, shares purchased under these plans are either original issue shares purchased directly from the Company or shares purchased on the open market by an independent agent.

During 2007, the Company issued 2,070,613 original issue shares of common stock as a result of stock option exercises and 25,000 original issue shares for restricted stock awards (non-vested stock as defined in SFAS 123R). Holders of stock options or restricted stock will often tender shares of common stock to the Company for payment of option exercise prices and/or applicable withholding taxes. During 2007, 731,793 shares of common stock were tendered to the Company for such purposes. The Company considers all shares tendered as cancelled shares restored to the status of authorized but unissued shares, in accordance with New Jersey law. There were also 6,000 restricted stock award shares forfeited during 2007.

The Company also has a Director Stock Program under which it issues shares of the Company common stock to its non-employee directors as partial consideration for their services as directors. Under this program, the Company issued 9,146 original issue shares of common stock to the non-employee directors of the Company during 2007.

On December 8, 2005, the Company's Board of Directors authorized the Company to implement a share repurchase program, whereby the Company may repurchase outstanding shares of common stock, up to an aggregate amount of 8 million shares in the open market or through privately negotiated transactions. During 2007, the Company repurchased 1,308,328 shares for $48.1 million under this program, funded with cash provided by operating activities and/or through the use of the Company's lines of credit. Since the repurchase program was implemented, the Company has repurchased 3,834,878 shares for $133.2 million.

Shareholder Rights Plan

In 1996, the Company's Board of Directors adopted a shareholder rights plan (Plan). The Plan has been amended three times since it was adopted and is now embodied in an Amended and Restated Rights Agreement effective September 1, 2007, which is an Exhibit to this Annual Report and Form 10-K.

The holders of the Company's common stock have one right (Right) for each of their shares. Each Right, which will initially be evidenced by the Company's common stock certificates representing the outstanding shares of common stock, entitles the holder to purchase one-half of one share of common stock at a purchase price of $65.00 per share, being $32.50 per half share, subject to adjustment (Purchase Price).

The Rights become exercisable upon the occurrence of a distribution date. At any time following a distribution date, each holder of a Right may exercise its right to receive common stock (or, under certain circumstances, other property of the Company) having a value equal to two times the Purchase Price of the Right then in effect. However, the Rights are subject to redemption or exchange by the Company prior to their exercise as described below.

A distribution date would occur upon the earlier of (i) ten days after the public announcement that a person or group has acquired, or obtained the right to acquire, beneficial ownership of the Company's common stock or other voting stock having 10% or more of the total voting power of the Company's common stock and other voting stock and (ii) ten days after the commencement or announcement by a person or group of an intention to

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make a tender or exchange offer that would result in that person acquiring, or obtaining the right to acquire, beneficial ownership of the Company's common stock or other voting stock having 10% or more of the total voting power of the Company's common stock and other voting stock.

In certain situations after a person or group has acquired beneficial ownership of 10% or more of the total voting power of the Company's stock as described above, each holder of a Right will have the right to exercise its Rights to receive common stock of the acquiring company having a value equal to two times the Purchase Price of the Right then in effect. These situations would arise if the Company is acquired in a merger or other business combination or if 50% or more of the Company's assets or earning power are sold or transferred.

At any time prior to the end of the business day on the tenth day following the announcement that a person or group has acquired, or obtained the right to acquire, beneficial ownership of 10% or more of the total voting power of the Company, the Company may redeem the Rights in whole, but not in part, at a price of $0.005 per Right, payable in cash or stock. A decision to redeem the Rights requires the vote of 75% of the Company's full Board of Directors. Also, at any time following the announcement that a person or group has acquired, or obtained the right to acquire, beneficial ownership of 10% or more of the total voting power of the Company, 75% of the Company's full Board of Directors may vote to exchange the Rights, in whole or in part, at an exchange rate of one share of common stock, or other property deemed to have the same value, per Right, subject to certain adjustments.

After a distribution date, Rights that are owned by an acquiring person will be null and void. Upon exercise of the Rights, the Company may need additional regulatory approvals to satisfy the requirements of the Rights Agreement. The Rights will expire on July 31, 2008, unless earlier than that date, they are exchanged or redeemed or the Plan is amended to extend the expiration date.

The Rights have anti-takeover effects because they will cause substantial dilution of the common stock if a person attempts to acquire the Company on terms not approved by the Board of Directors.

Stock Option and Stock Award Plans

The Company has various stock option and stock award plans which provide or provided for the issuance of one or more of the following to key employees: incentive stock options, nonqualified stock options, stock-settled SARs, restricted stock, performance units or performance shares. Stock options and stock-settled SARs under all plans have exercise prices equal to the average market price of Company common stock on the date of grant, and generally no option or stock-settled SAR is exercisable less than one year or more than ten years after the date of each grant.

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NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Transactions involving option shares for all plans are summarized as follows:

	Number of Shares Subject to Option	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (Years)	Aggregate Intrinsic Value (In thousands)
Outstanding at September 30, 2006	9,016,254	$ 24.69		
Granted in 2007	448,000	$ 39.48		
Exercised in 2007	(2,070,613)	$ 23.65		
Forfeited in 2007	(33,600)	$ 25.39		
Outstanding at September 30, 2007	7,360,041	$ 25.89	3.96	$ 154,007
Option shares exercisable at September 30, 2007	6,875,041	$ 24.99	3.62	$ 150,038
Option shares available for future grant at September 30, 2007(1)	1,075,397			

(1) Including shares available for stock-settled SARs and restricted stock grants.

The following table summarizes information about options outstanding at September 30, 2007:

	Options Outstanding			Options Exercisable	
Range of Exercise Price	Number Outstanding at 9/30/07	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number Exercisable at 9/30/07	Weighted Average Price
$20.60-$24.72	4,233,174	2.8	$ 22.72	4,213,174	$ 22.73
$24.73-$28.84	2,361,867	4.4	$ 27.72	2,361,867	$ 27.72
$28.85-$32.96	—	—	—	—	—
$32.97-$37.08	300,000	8.6	$ 35.11	300,000	$ 35.11
$37.09-$41.20	465,000	9.2	$ 39.39	—	—

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NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Transactions involving stock-settled SARs for all plans are summarized as follows:

	Number of Shares Subject to Option	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (Years)	Aggregate Intrinsic Value (In thousands)
Outstanding at September 30, 2006	—	$ —		
Granted in 2007	50,000	$ 41.20		
Exercised in 2007	—	$ —		
Forfeited in 2007	—	$ —		
Outstanding at September 30, 2007	50,000	$ 41.20	9.45	$ 281
Stock-settled SARs exercisable at September 30, 2007	—	—	—	$ —

The following table summarizes information about stock-settled SARs outstanding at September 30, 2007:

	Stock-Settled SARs Outstanding			Stock-Settled SARs Exercisable	
Range of Exercise Price	Number Outstanding at 9/30/07	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number Exercisable at 9/30/07	Weighted Average Exercise Price
$37.09-$41.20	50,000	9.5	$ 41.20	—	—

Restricted Share Awards

Restricted stock is subject to restrictions on vesting and transferability. Restricted stock awards entitle the participants to full dividend and voting rights. The market value of restricted stock on the date of the award is recorded as compensation expense over the vesting period. Certificates for shares of restricted stock awarded under the Company's stock option and stock award plans are held by the Company during the periods in which the restrictions on vesting are effective.

Transactions involving restricted shares for all plans are summarized as follows:

	Number of Restricted Share Awards	Weighted Average Fair Value per Award
Restricted Share Awards Outstanding at September 30, 2006	42,328	$ 28.44
Granted in 2007	25,000	$ 40.18
Vested in 2007	(25,000)	$ 24.50
Forfeited in 2007	(6,000)	$ 34.94
Restricted Share Awards Outstanding at September 30, 2007	36,328	$ 38.16

Vesting restrictions for the outstanding shares of non-vested restricted stock at September 30, 2007 will lapse as follows: 2008 — 2,500 shares; 2009 — 2,500 shares; 2010 — 28,828 shares; and 2011 — 2,500 shares.

Redeemable Preferred Stock

As of September 30, 2007, there were 10,000,000 shares of $1 par value Preferred Stock authorized but unissued.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Long-Term Debt

The outstanding long-term debt is as follows:

	At September 30 2007	At September 30 2006
	(Thousands)	
Medium-Term Notes(1):		
6.0% to 7.50% due May 2008 to June 2025	$ 749,000	$ 749,000
Notes(1):		
5.25% to 6.5% due March 2013 to September 2022(2)	250,000	346,665
	999,000	1,095,665
Other Notes:		
Secured(3)	—	22,766
Unsecured	24	169
Total Long-Term Debt	999,024	1,118,600
Less Current Portion	200,024	22,925
	$ 799,000	$ 1,095,675

(1) These medium-term notes and notes are unsecured.

(2) At September 30, 2006, $96,665,000 of the 6.5% unsecured notes were redeemable at par at any time after September 15, 2006. On April 30, 2007, the Company redeemed these notes for $96.3 million, plus accrued interest.

(3) On December 8, 2006, the Company repaid these notes for $22.8 million. As such, the notes were classified as Current Portion of Long-Term Debt on the Company's Consolidated Balance Sheet at September 30, 2006. These notes constituted "project financing" that was secured by the various project documentation and natural gas transportation contracts related to the Empire State Pipeline. The interest rate on these notes was a variable rate based on LIBOR.

As of September 30, 2007, the aggregate principal amounts of long-term debt maturing during the next five years and thereafter are as follows: $200.0 million in 2008, $100.0 million in 2009, zero in 2010, $200.0 million in 2011, $150.0 million in 2012, and $349.0 million thereafter.

Short-Term Borrowings

The Company historically has obtained short-term funds either through bank loans or the issuance of commercial paper. As for the former, the Company maintains a number of individual uncommitted or discretionary lines of credit with certain financial institutions for general corporate purposes. Borrowings under these lines of credit are made at competitive market rates. These credit lines, which aggregate to $455.0 million, are revocable at the option of the financial institutions and are reviewed on an annual basis. The Company anticipates that these lines of credit will continue to be renewed, or replaced by similar lines. The total amount available to be issued under the Company's commercial paper program is $300.0 million. The commercial paper program is backed by a syndicated committed credit facility totaling $300.0 million that extends through September 30, 2010.

At September 30, 2007 and 2006, the Company had no outstanding short-term notes payable to banks or commercial paper.

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Debt Restrictions

Under the Company's committed credit facility, the Company has agreed that its debt to capitalization ratio will not exceed .65 at the last day of any fiscal quarter from September 30, 2005 through September 30, 2010. At September 30, 2007, the Company's debt to capitalization ratio (as calculated under the facility) was .38. The constraints specified in the committed credit facility would permit an additional $2.02 billion in short-term and/or long-term debt to be outstanding (further limited by the indenture covenants discussed below) before the Company's debt to capitalization ratio would exceed .65. If a downgrade in any of the Company's credit ratings were to occur, access to the commercial paper markets might not be possible. However, the Company expects that it could borrow under its uncommitted bank lines of credit or rely upon other liquidity sources, including cash provided by operations.

Under the Company's existing indenture covenants, at September 30, 2007, the Company would have been permitted to issue up to a maximum of $1.4 billion in additional long-term unsecured indebtedness at then current market interest rates in addition to being able to issue new indebtedness to replace maturing debt.

The Company's 1974 indenture pursuant to which $399.0 million (or 40%) of the Company's long-term debt (as of September 30, 2007) was issued contains a cross-default provision whereby the failure by the Company to perform certain obligations under other borrowing arrangements could trigger an obligation to repay the debt outstanding under the indenture. In particular, a repayment obligation could be triggered if the Company fails (i) to pay any scheduled principal or interest or any debt under any other indenture or agreement or (ii) to perform any other term in any other such indenture or agreement, and the effect of the failure causes, or would permit the holders of the debt to cause, the debt under such indenture or agreement to become due prior to its stated maturity, unless cured or waived.

The Company's $300.0 million committed credit facility also contains a cross-default provision whereby the failure by the Company or its significant subsidiaries to make payments under other borrowing arrangements, or the occurrence of certain events affecting those other borrowing arrangements, could trigger an obligation to repay any amounts outstanding under the committed credit facility. In particular, a repayment obligation could be triggered if (i) the Company or any of its significant subsidiaries fail to make a payment when due of any principal or interest on any other indebtedness aggregating $20.0 million or more or (ii) an event occurs that causes, or would permit the holders of any other indebtedness aggregating $20.0 million or more to cause, such indebtedness to become due prior to its stated maturity. As of September 30, 2007, the Company had no debt outstanding under the committed credit facility.

Note F — Financial Instruments

Fair Values

The fair market value of the Company's long-term debt is estimated based on quoted market prices of similar issues having the same remaining maturities, redemption terms and credit ratings. Based on these criteria, the fair market value of long-term debt, including current portion, was as follows:

	At September 30			
	2007 Carrying Amount	2007 Fair Value	2006 Carrying Amount	2006 Fair Value
	(Thousands)			
Long-Term Debt	$ 999,024	$ 1,024,417	$ 1,118,600	$ 1,148,089

The fair value amounts are not intended to reflect principal amounts that the Company will ultimately be required to pay.

Temporary cash investments, notes payable to banks and commercial paper are stated at cost, which approximates their fair value due to the short-term maturities of those financial instruments. Investments in life insurance are stated at their cash surrender values as discussed below. Investments in an equity mutual fund and the stock of an insurance company (marketable equity securities), as discussed below, are stated at fair value based on quoted market prices.

Other Investments

Other investments includes cash surrender values of insurance contracts and marketable equity securities. The cash surrender values of the insurance contracts amounted to $54.7 million and $62.5 million at September 30, 2007 and 2006, respectively. The fair value of the equity mutual fund was $14.7 million and $12.9 million at September 30, 2007 and 2006, respectively. The gross unrealized gain on this equity mutual fund was $2.2 million and $1.0 million at September 30, 2007 and 2006, respectively. During 2005, the Company sold all of its interest in one equity mutual fund for $8.5 million and reinvested the proceeds in another equity mutual fund. The Company recognized a gain of $0.7 million on the sale of the equity mutual fund. The fair value of the stock of an insurance company was $16.3 million and $12.7 million at September 30, 2007 and 2006, respectively. The gross unrealized gain on this stock was $13.8 million and $10.3 million at September 30, 2007 and 2006, respectively. The insurance contracts and marketable equity securities are primarily informal funding mechanisms for various benefit obligations the Company has to certain employees.

Derivative Financial Instruments

The Company uses a variety of derivative financial instruments to manage a portion of the market risk associated with the fluctuations in the price of natural gas and crude oil. These instruments include price swap agreements, no cost collars and futures contracts.

Under the price swap agreements, the Company receives monthly payments from (or makes payments to) other parties based upon the difference between a fixed price and a variable price as specified by the agreement. The variable price is either a crude oil or natural gas price quoted on the NYMEX or a quoted natural gas price in various national natural gas publications. The majority of these derivative financial instruments are accounted for as cash flow hedges and are used to lock in a price for the anticipated sale of natural gas and crude oil production in the Exploration and Production segment and the All Other category. The Energy Marketing segment accounts for these derivative financial instruments as fair value hedges and uses them to hedge against falling prices, a risk to which they are exposed on their fixed price gas purchase commitments. The Energy Marketing segment also uses these derivative financial instruments to hedge against rising prices, a risk to which they are exposed on their fixed price sales commitments. At September 30, 2007, the Company had natural gas price swap agreements covering a notional amount of 13.2 Bcf extending through 2009 at a weighted average fixed rate of $8.20 per Mcf. Of this amount, 0.5 Bcf is accounted for as fair value hedges at a weighted average fixed rate of $6.94 per Mcf. The remaining 12.7 Bcf are accounted for as cash flow hedges at a weighted average fixed rate of $8.24 per Mcf. At September 30, 2007, the Company would have received a net $2.8 million to terminate the price swap agreements. The Company also had crude oil price swap agreements covering a notional amount of 1,485,000 bbls extending through 2009 at a weighted average fixed rate of $57.35 per bbl. At September 30, 2007, the Company would have had to pay a net $11.2 million to terminate the price swap agreements.

Under the no cost collars, the Company receives monthly payments from (or makes payments to) other parties when a variable price falls below an established floor price (the Company receives payment from the counterparty) or exceeds an established ceiling price (the Company pays the counterparty). The variable price is either a crude oil price quoted on the NYMEX or a quoted natural gas price in various national natural gas publications. These derivative financial instruments are accounted for as cash flow hedges and are used to lock in a price range for the anticipated sale of natural gas and crude oil production in the Exploration and Production segment. At September 30, 2007, the Company had no cost collars on natural gas covering a notional amount of 1.4 Bcf extending through 2008 with a weighted average floor price of $8.83 per Mcf and a weighted average ceiling price of $16.45 per Mcf. At September 30, 2007, the Company would have received $1.9 million to terminate the no cost collars.

At September 30, 2007, the Company had long (purchased) futures contracts covering 8.7 Bcf of gas extending through 2012 at a weighted average contract price of $8.72 per Mcf. They are accounted for as fair value hedges and are used by the Company's Energy Marketing segment to hedge against rising prices, a risk to which this segment is exposed due to the fixed price gas sales commitments that it enters into with residential, commercial and industrial customers. The Company would have had to pay $6.0 million to terminate these futures contracts at September 30, 2007.

At September 30, 2007, the Company had short (sold) futures contracts covering 5.9 Bcf of gas extending through 2009 at a weighted average contract price of $9.67 per Mcf. Of this amount, 3.9 Bcf is accounted for as cash flow hedges as these contracts relate to the anticipated sale of natural gas by the Energy Marketing segment. The remaining 2.0 Bcf is accounted for as fair value hedges used to hedge against falling prices on their fixed price gas purchasing commitments and hedge against decreases in natural gas prices associated with the eventual sale of gas in storage. The Company would have received $8.2 million to terminate these futures contracts at September 30, 2007.

The Company may be exposed to credit risk on some of the derivative financial instruments discussed above. Credit risk relates to the risk of loss that the Company would incur as a result of nonperformance by counterparties pursuant to the terms of their contractual obligations. To mitigate such credit risk, management performs a credit check, and then on an ongoing basis monitors counterparty credit exposure. Management has obtained guarantees from many of the parent companies of the respective counterparties to its derivative financial instruments. At September 30, 2007, the Company used nine counterparties for its over the counter derivative financial instruments. At September 30, 2007, no individual counterparty represented greater than 32% of total credit risk (measured as volumes hedged by an individual counterparty as a percentage of the Company's total volumes hedged). All of the counterparties (or the parent of the counterparty) were rated as investment grade entities at September 30, 2007.

In August 2007, the Exploration and Production segment's investment in Canada was sold. Of the $232.1 million in net proceeds received, $58.0 million was placed in escrow (denominated in Canadian dollars) pending receipt of a tax clearance certificate from the Canadian government. To hedge against foreign currency exchange risk, the Company entered into a $58.0 million forward contract to sell Canadian dollars. At September 30, 2007, due to the increase in the strength of the Canadian dollar versus the U.S. dollar, the Company had a $2.7 million derivative liability related to the collar. The Company records gains or losses associated with this forward contract directly to the income statement.

Note G — Retirement Plan and Other Post-Retirement Benefits

The Company has a tax-qualified, noncontributory, defined-benefit retirement plan (Retirement Plan) that covers approximately 73% of the employees of the Company. The Company provides health care and life insurance benefits for a majority of its retired employees under a post-retirement benefit plan (Post-Retirement Plan).

The Company's policy is to fund the Retirement Plan with at least an amount necessary to satisfy the minimum funding requirements of applicable laws and regulations and not more than the maximum amount deductible for federal income tax purposes. The Company has established VEBA trusts for its Post-Retirement Plan. Contributions to the VEBA trusts are tax deductible, subject to limitations contained in the Internal Revenue Code and regulations and are made to fund employees' post-retirement health care and life insurance benefits, as well as benefits as they are paid to current retirees. In addition, the Company has established 401(h) accounts for its Post-Retirement Plan. They are separate accounts within the Retirement Plan used to pay retiree medical benefits for the associated participants in the Retirement Plan. Contributions are tax-deductible when

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

made, subject to limitations contained in the Internal Revenue Code and regulations. Retirement Plan and Post-Retirement Plan assets primarily consist of equity and fixed income investments or units in commingled funds or money market funds.

The expected returns on plan assets of the Retirement Plan and Post-Retirement Plan are applied to the market-related value of plan assets of the respective plans. The market-related values of the Retirement Plan and Post-Retirement Plan assets are equal to market value as of the measurement date.

Reconciliations of the Benefit Obligations, Plan Assets and Funded Status, as well as the components of Net Periodic Benefit Cost and the Weighted Average Assumptions of the Retirement Plan and Post-Retirement Plan are shown in the tables below. The date used to measure the Benefit Obligations, Plan Assets and Funded Status is June 30, 2007, 2006 and 2005, respectively.

	Retirement Plan			Other Post-Retirement Benefits		
	Year Ended September 30			Year Ended September 30		
	2007	2006	2005	2007	2006	2005
	(Thousands)					
Change in Benefit Obligation						
Benefit Obligation at Beginning of Period	$ 732,207	$ 825,204	$ 693,532	$ 445,931	$ 546,273	$ 422,003
Service Cost	12,898	16,416	13,714	5,614	8,029	6,153
Interest Cost	44,350	40,196	42,079	27,198	26,804	25,783
Plan Participants' Contributions	—	—	—	1,566	1,559	1,017
Retiree Drug Subsidy Receipts	—	—	—	1,325	—	—
Actuarial (Gain) Loss	(2,986)	(108,112)	115,128	(14,450)	(115,052)	110,663
Benefits Paid	(43,950)	(41,497)	(39,249)	(22,639)	(21,682)	(19,346)
Benefit Obligation at End of Period	$ 742,519	$ 732,207	$ 825,204	$ 444,545	$ 445,931	$ 546,273
Change in Plan Assets						
Fair Value of Assets at Beginning of Period	$ 664,521	$ 616,462	$ 573,366	$ 325,624	$ 271,636	$ 229,485
Actual Return on Plan Assets	119,662	68,649	56,201	65,552	34,785	20,577
Employer Contributions	16,488	20,907	26,144	42,268	39,326	39,903
Employer Contributions During Period from Measurement Date to Fiscal Year End	8,423	—	—	—	—	—
Plan Participants' Contributions	—	—	—	1,566	1,559	1,017
Benefits Paid	(43,950)	(41,497)	(39,249)	(22,639)	(21,682)	(19,346)
Fair Value of Assets at End of Period	$ 765,144	$ 664,521	$ 616,462	$ 412,371	$ 325,624	$ 271,636
Reconciliation of Funded Status						
Funded Status	$ 22,625	$ (67,686)	$ (208,742)	$ (32,174)	$ (120,307)	$ (274,637)
Unrecognized Net Actuarial Loss	—	107,626	257,553	—	54,487	205,423
Unrecognized Transition Obligation	—	—	—	—	49,890	57,017
Unrecognized Prior Service Cost	—	7,185	8,142	—	12	17
Net Amount Recognized at End of Period	$ 22,625	$ 47,125	$ 56,953	$ (32,174)	$ (15,918)	$ (12,180)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Retirement Plan Year Ended September 30			Other Post-Retirement Benefits Year Ended September 30		
	2007	2006	2005	2007	2006	2005
	(Thousands)					
Amounts Recognized in the Balance Sheets Consist of:						
Accrued Benefit Liability	$ —	$ —	$ (117,103)	$ (70,555)	$ (32,918)	$ (26,584)
Prepaid Benefit Cost	22,625	47,125	—	38,381	17,000	14,404
Intangible Assets	—	—	8,142	—	—	—
Accumulated Other Comprehensive Loss from Additional Minimum Pension Liability Adjustment (Pre-Tax)	—	—	165,914	—	—	—
Net Amount Recognized at End of Period	$ 22,625	$ 47,125	$ 56,953	$ (32,174)	$ (15,918)	$ (12,180)
Weighted Average Assumptions Used to Determine Benefit Obligation at September 30						
Discount Rate	6.25%	6.25%	5.00%	6.25%	6.25%	5.00%
Expected Return on Plan Assets	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%
Rate of Compensation Increase	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
Components of Net Periodic Benefit Cost						
Service Cost	$ 12,898	$ 16,416	$ 13,714	$ 5,614	$ 8,029	$ 6,153
Interest Cost	44,350	40,196	42,079	27,198	26,804	25,783
Expected Return on Plan Assets	(51,235)	(49,943)	(49,545)	(26,960)	(22,302)	(18,862)
Amortization of Prior Service Cost	882	957	1,029	4	4	4
Amortization of Transition Amount	—	—	—	7,127	7,127	7,127
Recognition of Actuarial Loss(1)	13,528	23,108	10,473	8,214	23,402	12,467
Net Amortization and Deferral for Regulatory Purposes	1,211	(6,409)	1,988	16,220	(11,084)	(410)
Net Periodic Benefit Cost	$ 21,634	$ 24,325	$ 19,738	$ 37,417	$ 31,980	$ 32,262
Other Comprehensive (Income) Loss (Pre-Tax) Attributable to Change In Additional Minimum Liability Recognition	$ —	$ (165,914)	$ 83,379	$ —	$ —	$ —
Accumulated Other Comprehensive Loss (Pre-Tax) Attributable to Adoption of SFAS 158	$ 11,256	NA	NA	$ 778	NA	NA
Weighted Average Assumptions Used to Determine Net Periodic Benefit Cost at September 30						
Discount Rate	6.25%	5.00%	6.25%	6.25%	5.00%	6.25%
Expected Return on Plan Assets	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%
Rate of Compensation Increase	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%

(1) Distribution Corporation's New York jurisdiction calculates the amortization of the actuarial loss on a vintage year basis over 10 years, as mandated by the NYPSC. All the other subsidiaries of the Company utilize the corridor approach.

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The Net Periodic Benefit Cost in the table above includes the effects of regulation. The Company recovers pension and post-retirement benefit costs in its Utility and Pipeline and Storage segments in accordance with the applicable regulatory commission authorizations. Certain of those commission authorizations established tracking mechanisms which allow the Company to record the difference between the amount of pension and post-retirement benefit costs recoverable in rates and the amounts of such costs as determined under SFAS 87 and SFAS 106 as either a regulatory asset or liability, as appropriate. Any activity under the tracking mechanisms (including the amortization of pension and post-retirement regulatory assets) is reflected in the Net Amortization and Deferral for Regulatory Purposes line item above.

In September 2006, the FASB issued SFAS 158, an amendment of SFAS 87, SFAS 88, SFAS 106, and SFAS 132R. SFAS 158 requires that companies recognize a net liability or asset to report the underfunded or overfunded status of their defined benefit pension and other post-retirement benefit plans on their balance sheets, as well as recognize changes in the funded status of a defined benefit post-retirement plan in the year in which the changes occur through comprehensive income. The pronouncement also specifies that a plan's assets and obligations that determine its funded status be measured as of the end of Company's fiscal year, with limited exceptions. Under SFAS 158, certain previously unrecognized actuarial gains and losses and previously unrecognized prior service costs for both the pension and other post-retirement benefit plans as well as a previously unrecognized transition obligation for the other post-retirement benefit plan are required to be recognized. These amounts were not required to be recorded on the Company's Consolidated Balance Sheet before the adoption of SFAS 158, but were instead amortized over a period of time. In accordance with SFAS 158, the Company has recognized the funded status of its benefit plans and implemented the disclosure requirements of SFAS 158 at September 30, 2007. The requirement to measure the plan assets and benefit obligations as of the Company's fiscal year-end date will be adopted by the Company by the end of fiscal 2009. Currently, the Company measures its plan assets and benefit obligations using a June 30th measurement date. The incremental effects of adopting the provisions of SFAS 158 on the Company's Consolidated Balance Sheet at September 30, 2007 are presented in the table below:

	Before Application of SFAS 158(1)	Consolidated SFAS 158 Impact	After Application of SFAS 158
		(Thousands)	
Qualified Retirement Plan			
Reduction in Prepaid Pension and Post-Retirement Benefit Costs	$ 51,612	$ (28,987)	$ 22,625
Increase in Other Regulatory Assets Related to SFAS 158	$ —	$ 17,731	$ 17,731
Reduction in Accumulated Other Comprehensive Income	$ —	$ 7,008	$ 7,008
Reduction in Deferred Income Taxes (under Deferred Credits)	$ —	$ 4,248	$ 4,248

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Before Application of SFAS 158(1)	Consolidated SFAS 158 Impact	After Application of SFAS 158
		(Thousands)	
Other Post-Retirement Benefits			
Increase in Prepaid Pension and Post-Retirement Benefit Costs	$ 26,067	$ 12,314	$ 38,381
Increase in Other Regulatory Assets Related to SFAS 158	$ —	$ 38,472	$ 38,472
Increase in Other Regulatory Liabilities Related to SFAS 158	$ —	$ (3,247)	$ (3,247)
Reduction in Accumulated Other Comprehensive Income	$ —	$ 484	$ 484
Reduction in Deferred Income Taxes (under Deferred Credits)	$ —	$ 294	$ 294
Increase in Post-Retirement Liabilities	$ (22,238)	$ (48,317)	$ (70,555)
Non-Qualified Benefit Plan			
Increase in Other Regulatory Assets Related to SFAS 158	$ —	$ 5,704	$ 5,704
Reduction in Accumulated Other Comprehensive Income	$ —	$ 4,990	$ 4,990
Reduction in Deferred Income Taxes (under Deferred Credits)	$ —	$ 3,027	$ 3,027
Increase in Other Deferred Credits	$ (30,115)	$ (13,721)	$ (43,836)
Total Consolidated			
Reduction in Prepaid Pension and Post-Retirement Benefit Costs	$ 77,679	$ (16,673)	$ 61,006
Increase in Other Regulatory Assets Related to SFAS 158	$ —	$ 61,907	$ 61,907
Increase in Other Regulatory Liabilities Related to SFAS 158	$ —	$ (3,247)	$ (3,247)
Reduction in Accumulated Other Comprehensive Income	$ —	$ 12,482	$ 12,482
Reduction in Deferred Income Taxes (under Deferred Credits)	$ —	$ 7,569	$ 7,569
Increase in Post-Retirement Liabilities	$ (22,238)	$ (48,317)	$ (70,555)
Increase in Other Deferred Credits	$ (30,115)	$ (13,721)	$ (43,836)

(1) Amounts represent balances before applying the effects of the adoption of SFAS 158, but after giving effect to any necessary adjustments as a result of recognizing an additional minimum pension liability. At September 30, 2007, there was no additional minimum pension liability adjustment since the fair value of the plan assets exceeded the accumulated benefit obligation.

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NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The amounts recognized in accumulated other comprehensive loss, regulatory assets, and regulatory liabilities in fiscal 2007, as well as the amounts expected to be recognized in net periodic benefit cost in fiscal 2008 are presented in the table below:

	Retirement Plan	Other Post-Retirement Benefits (Thousands)	Non-Qualified Benefit Plan
Amounts Recognized In Accumulated Other Comprehensive Loss, Regulatory Assets and Regulatory Liabilities(1)			
Net Actuarial Gain/(Loss)	$ (22,684)	$ 6,768	$ (13,605)
Transition Obligation	—	(42,763)	—
Prior Service Cost	(6,303)	(8)	(116)
Net Amount Recognized	$ (28,987)	$ (36,003)	$ (13,721)
Amounts Expected to be Recognized in Net Periodic Benefit Cost in the Next Fiscal Year(1)			
Net Actuarial Gain/(Loss)	$ (11,064)	$ (2,927)	$ (1,218)
Transition Obligation	—	(7,127)	—
Prior Service Cost	(808)	(4)	(106)
Net Amount Expected to be Recognized	$ (11,872)	$ (10,058)	$ (1,324)

(1) Amounts presented are shown before recognizing deferred taxes.

In accordance with the provisions of SFAS 87, the Company recorded an additional minimum pension liability at September 30, 2005 representing the excess of the accumulated benefit obligation over the fair value of plan assets plus accrued amounts previously recorded. An intangible asset, as shown in the table above, offset the additional liability to the extent of previously Unrecognized Prior Service Cost. The amount in excess of Unrecognized Prior Service Cost was recorded net of the related tax benefit as accumulated other comprehensive loss. At September 30, 2006, the Company reversed the additional minimum pension liability, intangible asset and accumulated other comprehensive loss recorded in prior years since the fair value of the plan assets exceeded the accumulated benefit obligation at September 30, 2006. The pre-tax amounts of the change in accumulated other comprehensive (income) loss related to the additional minimum pension liability adjustment at September 30, 2006 and 2005 are shown in the table above. At September 30, 2007, prior to recognizing the impact of adopting SFAS 158, there was no additional minimum pension liability adjustment recorded since the fair value of the plan assets exceeded the accumulated benefit obligation. The projected benefit obligation, accumulated benefit obligation and fair value of assets for the Retirement Plan were as follows:

	2007	2006	2005
Projected Benefit Obligation	$ 742,519	$ 732,207	$ 825,204
Accumulated Benefit Obligation	$ 672,340	$ 660,026	$ 733,565
Fair Value of Plan Assets	$ 765,144	$ 664,520	$ 616,462

In 2007, other actuarial experience decreased the projected benefit obligation for the Retirement Plan by $3.0 million. There was no change to the discount rate used to estimate the projected benefit obligation for the Retirement Plan during 2007. The effect of the discount rate change for the Retirement Plan in 2006 was to decrease the projected benefit obligation of the Retirement Plan by $113.1 million. The discount rate change for the Retirement Plan in 2005 caused the projected benefit obligation to increase by $113.0 million.

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The Company made cash contributions totaling $24.9 million to the Retirement Plan during the year ended September 30, 2007. The Company expects that the annual contribution to the Retirement Plan in 2008 will be in the range of $15.0 million to $20.0 million. The following benefit payments, which reflect expected future service, are expected to be paid during the next five years and the five years thereafter: $46.7 million in 2008; $47.8 million in 2009; $49.0 million in 2010; $50.1 million in 2011; $51.3 million in 2012; and $283.3 million in the five years thereafter.

The Retirement Plan covers certain domestic employees hired before July 1, 2003. Employees hired after June 30, 2003 are eligible for a Retirement Savings Account benefit provided under the Company's defined contribution Tax-Deferred Savings Plans. Costs associated with the Retirement Savings Account benefit have been $0.4 million through September 30, 2007 (with $0.2 million and $0.1 million of costs occurring in 2007 and 2006, respectively). Costs associated with the Company's contributions to the Tax-Deferred Savings Plans were $4.1 million, $4.1 million, and $4.2 million for the years ended September 30, 2007, 2006 and 2005, respectively.

In addition to the Retirement Plan discussed above, the Company also has a Non Qualified benefit plan that covers a group of management employees designated by the Chief Executive Officer of the Company. This plan provides for defined benefit payments upon retirement of the management employee, or to the spouse upon death of the management employee. The net periodic benefit cost associated with this plan was $5.5 million, $5.4 million and $4.3 million in 2007, 2006 and 2005, respectively. For 2007, accumulated other comprehensive loss (pre-tax) of $8.0 million was recognized attributable to the adoption of SFAS 158. There were no amounts recognized in other comprehensive income (loss) attributable to the recognition of an additional minimum liability for 2006 and 2005. The accumulated benefit obligation for this plan was $28.8 million and $26.5 million at September 30, 2007 and 2006, respectively. The projected benefit obligation for the plan was $43.8 million and $44.5 million at September 30, 2007 and 2006, respectively. The actuarial valuations for this plan were determined based on a discount rate of 6.25%, 6.25% and 5.0% as of September 30, 2007, 2006 and 2005, respectively; a rate of compensation increase of 10.0% as of September 30, 2007, 2006 and 2005; and an expected long-term rate of return on plan assets of 8.25% at September 30, 2007, 2006 and 2005.

There was no change to the discount rate used to estimate the other post-retirement benefit obligation during 2007. Effective July 1, 2007, the Medicare Part B reimbursement trend, prescription drug trend and medical trend assumptions were changed. The effect of these assumption changes was to increase the other post-retirement benefit obligation by $8.6 million. Other actuarial experience decreased the other post-retirement benefit obligation in 2007 by $23.0 million.

The effect of the discount rate change in 2006 was to decrease the other post-retirement benefit obligation by $77.5 million. Effective July 1, 2006, the Medicare Part B reimbursement trend, prescription drug trend and medical trend assumptions were changed. The effect of these assumption changes was to decrease the other post-retirement benefit obligation by $1.7 million. A change in the disability assumption decreased the other post-retirement benefit obligation by $1.4 million. Other actuarial experience decreased the other post-retirement benefit obligation in 2006 by $34.4 million.

The effect of the discount rate change in 2005 was to increase the other post-retirement benefit obligation by $78.2 million. Effective July 1, 2005, the Medicare Part B reimbursement trend, prescription drug trend and medical trend assumptions were changed. The effect of these assumption changes was to increase the other post-retirement benefit obligation by $21.7 million. Also effective July 1, 2005, the percent of active female participants who are assumed to be married at retirement was changed. The effect of this assumption change was to decrease the other post-retirement benefit obligation by $6.9 million. Other actuarial experience increased the other post-retirement benefit obligation in 2005 by $17.9 million.

On December 8, 2003, the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (the Act) was signed into law. This Act introduced a prescription drug benefit under Medicare (Medicare Part D), as

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

well as a federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare Part D. In accordance with FASB Staff Position FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003", since the Company is assumed to continue to provide a prescription drug benefit to retirees in the point of service and indemnity plans that is at least actuarially equivalent to Medicare Part D, the impact of the Act was reflected as of December 8, 2003.

The estimated gross benefit payments and gross amount of subsidy receipts are as follows:

	Benefit Payments	Subsidy Receipts
First Year	$ 23,990,000	$ (1,522,000)
Second Year	$ 25,973,000	$ (1,745,000)
Third Year	$ 28,007,000	$ (1,954,000)
Fourth Year	$ 29,917,000	$ (2,154,000)
Fifth Year	$ 31,406,000	$ (2,401,000)
Next Five Years	$ 176,333,000	$ (15,391,000)

In 2005, the Company began making separate estimates of the annual rate of increase in the per capita cost of covered medical care benefits for Pre and Post age 65 participants. The rate of increase for Pre age 65 participants was assumed to be 10.0% while the rate of increase for Post age 65 participants was assumed to be 7.5%. In 2006, the rate of increase for Pre age 65 participants was 9.0% and was assumed to gradually decline to 5.0% by the year 2014. The rate of increase for the Post age 65 participants was 7.0% in 2006 and was assumed to gradually decline to 5.0% by the year 2014. In 2007, the rate of increase for Pre age 65 participants was 8.0% and was assumed to gradually decline to 5.0% by the year 2014. The rate of increase for the Post age 65 participants was 6.67% in 2007 and was assumed to gradually decline to 5.0% by the year 2014. The annual rate of increase in the per capita cost of covered prescription drug benefits was assumed to be 12.5% for 2005, 11.0% for 2006, 10.0% for 2007, and gradually decline to 5.0% by the year 2014 and remain level thereafter. The annual rate of increase in the per capita Medicare Part B Reimbursement was assumed to be 6.0% for 2005, 5.25% for 2006, and 7.0% for 2007. The annual rate of increase for the Medicare Part B Reimbursement is expected to gradually decline to 5.0% by the year 2016.

The health care cost trend rate assumptions used to calculate the per capita cost of covered medical care benefits have a significant effect on the amounts reported. If the health care cost trend rates were increased by 1% in each year, the Other Post-Retirement Benefit Obligation as of October 1, 2007 would increase by $55.6 million. This 1% change would also have increased the aggregate of the service and interest cost components of net periodic post-retirement benefit cost for 2007 by $4.9 million. If the health care cost trend rates were decreased by 1% in each year, the Other Post-Retirement Benefit Obligation as of October 1, 2007 would decrease by $46.6 million. This 1% change would also have decreased the aggregate of the service and interest cost components of net periodic post-retirement benefit cost for 2007 by $4.0 million.

The Company made cash contributions including payments made directly to participants totaling $42.3 million to the Post-Retirement Plan during the year ended September 30, 2007. The Company expects that the annual contribution to the Post-Retirement Plan in 2008 will be in the range of $25.0 million to $35.0 million.

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The Company's Retirement Plan weighted average asset allocations at September 30, 2007, 2006 and 2005 by asset category are as follows:

Asset Category	Target Allocation 2008	Percentage of Plan Assets at September 30 2007	2006	2005
Equity Securities	60-75%	70%	67%	63%
Fixed Income Securities	20-35%	24%	26%	28%
Other	0-15%	6%	7%	9%
Total		100%	100%	100%

The Company's Post-Retirement Plan weighted average asset allocations at September 30, 2007, 2006 and 2005 by asset category are as follows:

Asset Category	Target Allocation 2008	Percentage of Plan Assets at September 30 2007	2006	2005
Equity Securities	85-100%	95%	95%	92%
Fixed Income Securities	0-15%	1%	1%	2%
Other	0-15%	4%	4%	6%
Total		100%	100%	100%

The Company's assumption regarding the expected long-term rate of return on plan assets is 8.25%. The return assumption reflects the anticipated long-term rate of return on the plan's current and future assets. The Company utilizes historical investment data, projected capital market conditions, and the plan's target asset class and investment manager allocations to set the assumption regarding the expected return on plan assets.

The long-term investment objective of the Retirement Plan trust and the Post-Retirement Plan VEBA trusts is to achieve the target total return in accordance with the Company's risk tolerance. Assets are diversified utilizing a mix of equities, fixed income and other securities (including real estate). Risk tolerance is established through consideration of plan liabilities, plan funded status and corporate financial condition.

Investment managers are retained to manage separate pools of assets. Comparative market and peer group performance of individual managers and the total fund are monitored on a regular basis, and reviewed by the Company's Retirement Committee on at least a quarterly basis.

The discount rate which is used to present value the future benefit payment obligations of the Retirement Plan, the Non-Qualified benefit plan, and the Post-Retirement Plan is 6.25% as of September 30, 2007. This rate is equal to the Moody's Aa Long-Term Corporate Bond index, rounded to the nearest 25 basis points. The duration of the securities underlying that index (approximately 13 years) reasonably matches the expected timing of anticipated future benefit payments (approximately 12 years). The Company also utilizes a yield curve model to determine the discount rate. The yield curve is a spot rate yield curve that provides a zero-coupon interest rate for each year into the future. Each year's anticipated benefit payments are discounted at the associated spot interest rate back to the measurement date. The discount rate is then determined based on the spot interest rate that results in the same present value when applied to the same anticipated benefit payments.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Note H — Commitments and Contingencies

Environmental Matters

The Company is subject to various federal, state and local laws and regulations relating to the protection of the environment. The Company has established procedures for the ongoing evaluation of its operations, to identify potential environmental exposures and to comply with regulatory policies and procedures.

It is the Company's policy to accrue estimated environmental clean-up costs (investigation and remediation) when such amounts can reasonably be estimated and it is probable that the Company will be required to incur such costs. At September 30, 2007, the Company has estimated its remaining clean-up costs related to former manufactured gas plant sites and third party waste disposal sites will be in the range of $12.1 million to $15.8 million. The minimum estimated liability of $12.1 million has been recorded on the Consolidated Balance Sheet at September 30, 2007. The Company expects to recover its environmental clean-up costs from a combination of rate recovery and insurance proceeds (refer to Note C — Regulatory Matters for further discussion of the insurance proceeds). Other than as discussed below, the Company is currently not aware of any material exposure to environmental liabilities. However, adverse changes in environmental regulations, new information or other factors could impact the Company.

(i) Former Manufactured Gas Plant Sites

The Company has incurred or is incurring clean-up costs at four former manufactured gas plant sites in New York and Pennsylvania. The Company continues to be responsible for future ongoing maintenance at one site. At a second site, remediation is complete and long-term maintenance and monitoring activities are ongoing. A third site, which allegedly contains, among other things, manufactured gas plant waste, is in the investigation stage.

At a fourth former manufactured gas plant site, the Company received, in 1998 and again in October 1999, notice that the NYDEC believes the Company is responsible for contamination discovered at the site located in New York for which the Company had not been named as a PRP. In February 2007, the NYDEC identified the Company as a PRP for the site and issued a proposed remedial action plan. The NYDEC estimated clean-up costs under its proposed remedy to be $8.9 million if implemented. Although the Company commented to the NYDEC that the proposed remedial action plan contained a number of material errors, omissions and procedural defects, the NYDEC, in a March 2007 Record of Decision, selected the remedy it had previously proposed. In July 2007, the Company appealed the NYDEC's Record of Decision to the New York State Supreme Court, Albany County. The Company believes that a negotiated resolution with the NYDEC regarding the site remains possible.

(ii) Third Party Waste Disposal Sites

The Company was identified by the NYDEC or the EPA as one of a number of companies considered to be PRPs with respect to two waste disposal sites in New York which were operated by unrelated third parties. The PRPs were alleged to have contributed to the materials that may have been collected at such waste disposal sites by the site operators. The remediation was completed at one site, with costs subject to an ongoing final reallocation process among five PRPs. At a second waste disposal site, settlement was reached in the amount of $9.3 million to be allocated among five PRPs. In September 2007, the reallocation process was concluded with respect to both of these sites whereby the Company was released from any future liability related to these sites, and was allocated a refund of approximately $0.5 million as a result of the conclusion of the cost reallocation process.

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(iii) Other

In June 2007, the NYDEC notified the Company, as well as a number of other companies, of their liability with respect to a remedial account at a waste disposal site in New York. The notification identified the Company as one of approximately 400 other companies considered to be PRPs related to this site and requested that the remedy the NYDEC proposed in a Record of Decision issued in March 2006 be performed. The estimated clean-up costs under the remedy selected by the NYDEC are estimated to be approximately $13.0 million if implemented. The Company is in the process of organizing a group with the other PRPs and negotiating an Order on Consent with the NYDEC to perform the remedy. The Company has not been able to reasonably estimate the probability or extent of its share of potential liability at this site.

Other

The Company, in its Utility segment, Energy Marketing segment, and All Other category, has entered into contractual commitments in the ordinary course of business, including commitments to purchase gas, transportation, and storage service to meet customer gas supply needs. Substantially all of these contracts expire within the next five years. The future gas purchase, transportation and storage contract commitments during the next five years and thereafter are as follows: $766.5 million in 2008, $114.5 million in 2009, $50.8 million in 2010, $22.1 million in 2011, $8.8 million in 2012, and $23.3 million thereafter. In the Utility segment, these costs are subject to state commission review, and are being recovered in customer rates. Management believes that, to the extent any stranded pipeline costs are generated by the unbundling of services in the Utility segment's service territory, such costs will be recoverable from customers.

The Company has entered into leases for the use of buildings, vehicles, construction tools, meters, computer equipment and other items. These leases are accounted for as operating leases. The future lease commitments during the next five years and thereafter are as follows: $6.7 million in 2008, $5.8 million in 2009, $4.4 million in 2010, $2.9 million in 2011, $2.6 million in 2012, and $13.1 million thereafter.

The Company has entered into several contractual commitments associated with the construction of the Empire Connector project, including the pipeline construction itself and construction of a compressor station, as well as other contractual commitments for engineering and consulting services. The Empire Connector is scheduled to go in service by November 2008. As of September 30, 2007, the future contractual commitments related to the construction of the Empire Connector during the next two years are as follows: $118.3 million in 2008 and $0.6 million in 2009.

The Company is involved in other litigation arising in the normal course of business. In addition to the regulatory matters discussed in Note C — Regulatory Matters, the Company is involved in other regulatory matters arising in the normal course of business. These other litigation and regulatory matters may include, for example, negligence claims and tax, regulatory or other governmental audits, inspections, investigations and other proceedings. These matters may involve state and federal taxes, safety, compliance with regulations, rate base, cost of service and purchased gas cost issues, among other things. While these normal-course matters could have a material effect on earnings and cash flows in the period in which they are resolved, they are not expected to change materially the Company's present liquidity position, nor to have a material adverse effect on the financial condition of the Company.

Note I — Discontinued Operations

On August 31, 2007, the Company completed the sale of SECI, Seneca's wholly owned subsidiary that operated in Canada, to NAL Oil & Gas Trust. The Company received approximately $232.1 million of proceeds from the sale, of which $58.0 million was placed in escrow pending receipt of a tax clearance certificate from the Canadian government. The sale resulted in the recognition of a gain of approximately $120.3 million, net of tax, during the fourth quarter of 2007. SECI is engaged in the exploration for, and the development and purchase of,

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

natural gas and oil reserves in the provinces of Alberta, Saskatchewan and British Columbia in Canada. The decision to sell was based on lower than expected returns from the Canadian oil and gas properties combined with difficulty in finding significant new reserves. Seneca will continue its exploration and development activities in the Gulf of Mexico, in California and in Appalachia. As a result of the decision to sell SECI, the Company began presenting all SECI operations as discontinued operations during the fourth quarter of 2007.

The following is selected financial information of the discontinued operations for SECI:

	Year Ended September 30		
	2007	2006	2005
		(Thousands)	
Operating Revenues	$ 50,495	$ 71,984	$ 62,775
Operating Expenses	33,306	151,532	40,600
Operating Income (Loss)	17,189	(79,548)	22,175
Interest Income	1,082	866	260
Income (Loss) before Income Taxes	18,271	(78,682)	22,435
Income Tax Expense (Benefit)	2,792	(32,159)	7,357
Income (Loss) from Discontinued Operations	15,479	(46,523)	15,078
Gain on Disposal, Net of Taxes of $39,572	120,301	—	—
Income (Loss) from Discontinued Operations	$ 135,780	$ (46,523)	$ 15,078

On July 18, 2005, the Company completed the sale of its entire 85.16% interest in U.E., a district heating and electric generation business in the Bohemia region of the Czech Republic, to Czech Energy Holdings, a.s. for sales proceeds of approximately $116.3 million. The sale resulted in the recognition of a gain of approximately $25.8 million, net of tax, at September 30, 2005. Market conditions during 2005, including the increasing value of the Czech currency as compared to the U.S. dollar, caused the value of the assets of U.E. to increase, providing an opportunity to sell the U.E. operations at a profit for the Company. As a result of the decision to sell its majority interest in U.E., the Company began presenting the Czech Republic operations, which are primarily comprised of U.E., as discontinued operations in June 2005. U.E. was the major component of the Company's International segment. With this change in presentation, the Company discontinued all reporting for an International segment.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The following is selected financial information of the discontinued operations for U.E.:

	Year Ended September 30 2005 (Thousands)
Operating Revenues	$ 124,840
Operating Expenses	103,155
Operating Income	21,685
Other Income	2,048
Interest Expense	(558)
Income before Income Taxes and Minority Interest	23,175
Income Tax Expense	10,331
Minority Interest, Net of Taxes	2,645
Income from Discontinued Operations	10,199
Gain on Disposal, Net of Taxes of $1,612	25,774
Income from Discontinued Operations	$ 35,973

Note J — Business Segment Information

The Company has five reportable segments: Utility, Pipeline and Storage, Exploration and Production, Energy Marketing, and Timber. The breakdown of the Company's operations into reportable segments is based upon a combination of factors including differences in products and services, regulatory environment and geographic factors.

The Utility segment operations are regulated by the NYPSC and the PaPUC and are carried out by Distribution Corporation. Distribution Corporation sells natural gas to retail customers and provides natural gas transportation services in western New York and northwestern Pennsylvania.

The Pipeline and Storage segment operations are regulated. The FERC regulates the operations of Supply Corporation and the NYPSC regulates the operations of Empire. Supply Corporation transports and stores natural gas for utilities (including Distribution Corporation), natural gas marketers (including NFR) and pipeline companies in the northeastern United States markets. Empire transports natural gas from the United States/Canadian border near Buffalo, New York into Central New York just north of Syracuse, New York. Empire transports gas to major industrial companies, utilities (including Distribution Corporation) and power producers.

The Exploration and Production segment, through Seneca, is engaged in exploration for, and development and purchase of, natural gas and oil reserves in California, in the Appalachian region of the United States, and in the Gulf Coast region of Texas, Louisiana and Alabama. Seneca's production is, for the most part, sold to purchasers located in the vicinity of its wells. As disclosed in Note I — Discontinued Operations, on August 31, 2007, Seneca completed the sale of SECI, its wholly owned subsidiary operating in Canada, for a gain of approximately $120.3 million, net of tax, during the fourth quarter of 2007. As a result of the sale, SECI's operations have been reported as discontinued operations and previous period segment information has been restated to reflect this change.

The Energy Marketing segment is comprised of NFR's operations. NFR markets natural gas to industrial, commercial, public authority and residential end-users in western and central New York and northwestern Pennsylvania, offering competitively priced energy and energy management services for its customers.

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The Timber segment's operations are carried out by the Northeast division of Seneca and by Highland. This segment has timber holdings (primarily high quality hardwoods) in the northeastern United States and sawmills and kilns in Pennsylvania.

The data presented in the tables below reflect the reportable segments and reconciliations to consolidated amounts. The accounting policies of the segments are the same as those described in Note A — Summary of Significant Accounting Policies. Sales of products or services between segments are billed at regulated rates or at market rates, as applicable. The Company evaluates segment performance based on income before discontinued operations, extraordinary items and cumulative effects of changes in accounting (when applicable). When these items are not applicable, the Company evaluates performance based on net income.

As disclosed in Note I — Discontinued Operations, the Company completed the sale of its majority interest in U.E., a district heating and electric generation business in the Czech Republic, on July 18, 2005. As a result of the sale of its majority interest in U.E., the Company discontinued all reporting for an International segment. All Czech Republic operations have been reported as discontinued operations. Any remaining international activity has been included in corporate operations.

	Year Ended September 30, 2007								
	Utility	Pipeline and Storage	Exploration and Production	Energy Marketing	Timber	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
					(Thousands)				
Revenue from External Customers	$1,106,453	$130,410	$ 324,037	$413,612	$ 58,897	$2,033,409	$ 5,385	$ 772	$2,039,566
Intersegment Revenues	$ 14,271	$ 81,556	$ —	$ —	$ —	$ 95,827	$ 8,726	$ (104,553)	$ —
Interest Income	$ (2,345)	$ 357	$ 9,905	$ 682	$ 1,249	$ 9,848	$ 16	$ (8,314)	$ 1,550
Interest Expense	$ 28,190	$ 9,623	$ 51,743	$ 263	$ 3,265	$ 93,084	$ 2,687	$ (21,296)	$ 74,475
Depreciation, Depletion and Amortization	$ 40,541	$ 32,985	$ 78,174	$ 33	$ 4,709	$ 156,442	$ 785	$ 692	$ 157,919
Income Tax Expense	$ 31,642	$ 35,740	$ 52,421	$ 5,654	$ 2,818	$ 128,275	$ 1,647	$ 1,891	$ 131,813
Income from Unconsolidated Subsidiaries	$ —	$ —	$ —	$ —	$ —	$ —	$ 4,979	$ —	$ 4,979
Segment Profit: Income from Continuing Operations	$ 50,886	$ 56,386	$ 74,889	$ 7,663	$ 3,728	$ 193,552	$ 2,564	$ 5,559	$ 201,675
Expenditures for Additions to Long-Lived Assets from Continuing Operations	$ 54,185	$ 43,226	$ 146,687	$ 76	$ 3,657	$ 247,831	$ 87	$ (319)	$ 247,599
	At September 30, 2007								
					(Thousands)				
Segment Assets	$1,565,593	$810,957	$1,326,073	$ 59,802	$165,224	$3,927,649	$66,531	$ (105,768)	$3,888,412

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Year Ended September 30, 2006								
	Utility	Pipeline and Storage	Exploration and Production	Energy Marketing	Timber	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
					(Thousands)				
Revenue from External Customers	$1,265,695	$132,921	$ 274,896	$497,069	$ 65,024	$2,235,605	$ 3,304	$ 766	$2,239,675
Intersegment Revenues	$ 15,068	$ 81,431	$ —	$ —	$ 5	$ 96,504	$ 9,444	$ (105,948)	$ —
Interest Income	$ 4,889	$ 454	$ 7,816	$ 445	$ 747	$ 14,351	$ 22	$ (4,964)	$ 9,409
Interest Expense	$ 26,174	$ 6,620	$ 50,457	$ 227	$ 3,095	$ 86,573	$ 2,555	$ (10,547)	$ 78,581
Depreciation, Depletion and Amortization	$ 40,172	$ 36,876	$ 67,122	$ 53	$ 6,495	$ 150,718	$ 789	$ 492	$ 151,999
Income Tax Expense	$ 35,699	$ 33,896	$ 29,351	$ 3,748	$ 3,277	$ 105,971	$ 969	$ 1,305	$ 108,245
Income from Unconsolidated Subsidiaries	$ —	$ —	$ —	$ —	$ —	$ —	$ 3,583	$ —	$ 3,583
Segment Profit (Loss): Income (Loss) from Continuing Operations	$ 49,815	$ 55,633	$ 67,494	$ 5,798	$ 5,704	$ 184,444	$ 359	$ (189)	$ 184,614
Expenditures for Additions to Long-Lived Assets from Continuing Operations	$ 54,414	$ 26,023	$ 166,535	$ 16	$ 2,323	$ 249,311	$ 85	$ 2,995	$ 252,391
	At September 30, 2006								
					(Thousands)				
Segment Assets	$1,498,442	$767,889	$1,209,969(1)	$ 81,374	$159,421	$3,717,095	$64,287	$ (17,634)	$3,763,748

(1) Amount includes $134,930 of assets of SECI, which has been classified as discontinued operations as of September 30, 2007. (See Note I — Discontinued Operations).

	Year Ended September 30, 2005								
	Utility	Pipeline and Storage	Exploration and Production	Energy Marketing	Timber	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
					(Thousands)				
Revenue from External Customers	$ 1,101,572	$ 132,805	$ 230,650	$ 329,714	$ 61,285	$ 1,856,026	$ 4,748	$ —	$ 1,860,774
Intersegment Revenues	$ 15,495	$ 83,054	$ —	$ —	$ 1	$ 98,550	$ 8,606	$ (107,156)	$ —
Interest Income	$ 4,111	$ 76	$ 4,401	$ 783	$ 438	$ 9,809	$ 19	$ (3,592)	$ 6,236
Interest Expense	$ 22,900	$ 7,128	$ 48,856	$ 11	$ 2,764	$ 81,659	$ 1,726	$ (1,072)	$ 82,313
Depreciation, Depletion and Amortization	$ 40,159	$ 38,050	$ 67,647	$ 41	$ 6,601	$ 152,498	$ 3,537	$ 467	$ 156,502
Income Tax Expense (Benefit)	$ 23,102	$ 39,068	$ 20,996	$ 3,210	$ 2,271	$ 88,647	$ (1,425)	$ (1,601)	$ 85,621
Income from Unconsolidated Subsidiaries	$ —	$ —	$ —	$ —	$ —	$ —	$ 3,362	$ —	$ 3,362
Significant Non-Cash Item:									
Impairment of Investment in Partnership	$ —	$ —	$ —	$ —	$ —	$ —	$ (4,158)(1)	$ —	$ (4,158)
Segment Profit (Loss): Income (Loss) from Continuing Operations	$ 39,197	$ 60,454	$ 35,581	$ 5,077	$ 5,032	$ 145,341	$ (2,616)	$ (4,288)	$ 138,437
Expenditures for Additions to Long-Lived Assets from Continuing Operations	$ 50,071	$ 21,099	$ 83,972	$ 58	$ 18,894	$ 174,094	$ 463	$ 618	$ 175,175
	At September 30, 2005								
					(Thousands)				
Segment Assets	$ 1,423,597	$ 782,546	$ 1,213,525(2)	$ 92,470	$ 162,052	$ 3,674,190	$ 73,354	$ 2,209	$ 3,749,753

(1) Amount represents the impairment in the value of the Company's 50% investment in ESNE, a partnership that owns an 80-megawatt, combined cycle, natural gas-fired power plant in the town of North East, Pennsylvania.

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NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

(2) Amount includes $204,892 of assets of SECI, which has been classified as discontinued operations as of September 30, 2007. (See Note I — Discontinued Operations).

Geographic Information	For The Year Ended September 30 2007	2006 (Thousands)	2005
Revenues from External Customers(1):			
United States	$ 2,039,566	$ 2,239,675	$ 1,860,774

	At September 30 2007	2006 (Thousands)	2005
Long-Lived Assets:			
United States	$ 3,334,274	$ 3,181,769	$ 2,978,680
Assets of Discontinued Operations	—	97,234	171,196
	$ 3,334,274	$ 3,279,003	$ 3,149,876

(1) Revenue is based upon the country in which the sale originates. This table excludes revenues from Canadian discontinued operations of $50,495, $71,984 and $62,775 for September 30, 2007, 2006 and 2005, respectively.

Note K — Investments in Unconsolidated Subsidiaries

The Company's unconsolidated subsidiaries consist of equity method investments in Seneca Energy, Model City and ESNE. The Company has 50% interests in each of these entities. Seneca Energy and Model City generate and sell electricity using methane gas obtained from landfills owned by outside parties. ESNE generates electricity from an 80-megawatt, combined cycle, natural gas-fired power plant in North East, Pennsylvania. ESNE sells its electricity into the New York power grid.

During 2007, Horizon Power made capital contributions of $3.3 million to Seneca Energy. Seneca Energy is in the process of expanding its generating capacity from 11.2 megawatts to 17.6 megawatts.

In September 2005, the Company recorded an impairment of $4.2 million of its equity investment in ESNE due to a decline in the fair market value of ESNE. This impairment was recorded in accordance with APB 18.

A summary of the Company's investments in unconsolidated subsidiaries at September 30, 2007 and 2006 is as follows:

	At September 30 2007	2006
	(Thousands)	
ESNE	$ 4,652	$ 4,486
Seneca Energy	12,033	5,366
Model City	1,571	1,738
	$ 18,256	$ 11,590

Note L — Intangible Assets

As a result of the Empire and Toro acquisitions, the Company acquired certain intangible assets during 2003. In the case of the Empire acquisition, the intangible assets represent the fair value of various long-term transportation contracts with Empire's customers. In the case of the Toro acquisition, the intangible assets

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

represent the fair value of various long-term gas purchase contracts with the various landfills. These intangible assets are being amortized over the lives of the transportation and gas purchase contracts with no residual value at the end of the amortization period. The weighted-average amortization period for the gross carrying amount of the transportation contracts is 8 years. The weighted-average amortization period for the gross carrying amount of the gas purchase contracts is 20 years. Details of these intangible assets are as follows (in thousands):

	At September 30, 2007			At September 30, 2006
	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Net Carrying Amount
Intangible Assets Subject to Amortization:				
Long-Term Transportation Contracts	$ 8,580	$ (4,989)	$ 3,591	$ 4,660
Long-Term Gas Purchase Contracts	31,864	(6,619)	25,245	26,838
	$ 40,444	$ (11,608)	$ 28,836	$ 31,498
Aggregate Amortization Expense:				
For the Year Ended September 30, 2007	$ 2,662			
For the Year Ended September 30, 2006	$ 2,662			
For the Year Ended September 30, 2005	$ 2,662			

The gross carrying amount of intangible assets subject to amortization at September 30, 2007 remained unchanged from September 30, 2006. The only activity with regard to intangible assets subject to amortization was amortization expense as shown on the table above. Amortization expense for the long-term transportation contracts is estimated to be $1.1 million in 2008, $0.5 million in 2009, and $0.4 million in 2010, 2011 and 2012. Amortization expense for the long-term gas purchase contracts is estimated to be $1.6 million annually for 2008, 2009, 2010, 2011 and 2012.

Note M — Quarterly Financial Data (unaudited)

In the opinion of management, the following quarterly information includes all adjustments necessary for a fair statement of the results of operations for such periods. Per common share amounts are calculated using the weighted average number of shares outstanding during each quarter. The total of all quarters may differ from the per common share amounts shown on the Consolidated Statements of Income. Those per common share amounts are based on the weighted average number of shares outstanding for the entire fiscal year. Because of the seasonal nature of the Company's heating business, there are substantial variations in operations reported on a quarterly basis.

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Quarter Ended	Operating Revenues	Operating Income	Income from Continuing Operations	Income (Loss) from Discontinued Operations	Net Income Available for Common Stock	Earnings from Continuing Operations per Common Share Basic	Earnings from Continuing Operations per Common Share Diluted	Earnings per Common Share Basic	Earnings per Common Share Diluted
	(Thousands, except per common share amounts)								
2007									
9/30/2007	$ 302,030	$ 73,504	$ 34,295	$ 123,395(1)	$ 157,690(1)	$ 0.41	$ 0.40	$ 1.89	$ 1.84
6/30/2007	$ 448,779	$ 83,933	$ 41,212(2)	$ 5,586	$ 46,798(2)	$ 0.49	$ 0.48	$ 0.56	$ 0.55
3/31/2007	$ 798,100	$ 142,404	$ 75,480(3)	$ 2,967	$ 78,447(3)	$ 0.91	$ 0.89	$ 0.95	$ 0.92
12/31/2006	$ 490,657	$ 96,657	$ 50,688(4)	$ 3,832	$ 54,520(4)	$ 0.61	$ 0.60	$ 0.66	$ 0.64
2006									
9/30/2006	$ 280,506	$ 56,865	$ 28,585	$ (26,617)(5)	$ 1,968(5)	$ 0.34	$ 0.33	$ 0.02	$ 0.02
6/30/2006	$ 397,206	$ 67,122	$ 37,618(7)	$ (37,507)(6)	$ 111(6)(7)	$ 0.45	$ 0.44	$ —	$ —
3/31/2006	$ 874,700	$ 133,745	$ 69,650	$ 8,944(8)	$ 78,594(8)	$ 0.83	$ 0.81	$ 0.93	$ 0.91
12/31/2005	$ 687,263	$ 97,891	$ 48,761(9)	$ 8,657	$ 57,418(9)	$ 0.58	$ 0.57	$ 0.68	$ 0.67

(1) Includes a $120.3 million gain on the sale of SECI.

(2) Includes $4.8 million of income associated with the reversal of reserve for preliminary project costs associated with the Empire Connector project.

(3) Includes a $2.3 million of income associated with the reversal of a purchased gas expense accrual related to the resolution of a contingency.

(4) Includes a $1.9 million positive earnings impact associated with the discontinuance of hedge accounting on an interest rate collar.

(5) Includes expense of $29.1 million related to the impairment of oil and gas producing properties.

(6) Includes expense of $39.5 million related to the impairment of oil and gas producing properties.

(7) Includes income of $6.1 million related to income tax adjustments.

(8) Includes income of $5.1 million related to income tax adjustments.

(9) Includes income of $2.6 million related to a regulatory adjustment.

Note N — Market for Common Stock and Related Shareholder Matters (unaudited)

At September 30, 2007, there were 16,989 registered shareholders of Company common stock. The common stock is listed and traded on the New York Stock Exchange. Information related to restrictions on the payment of dividends can be found in Note E — Capitalization and Short-Term Borrowings. The quarterly price

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

ranges (based on intra-day prices) and quarterly dividends declared for the fiscal years ended September 30, 2007 and 2006, are shown below:

Quarter Ended	Price Range High	Price Range Low	Dividends Declared
2007			
9/30/2007	$ 47.00	$ 40.95	$ .31
6/30/2007	$ 47.87	$ 42.75	$ .31
3/31/2007	$ 43.79	$ 36.94	$ .30
12/31/2006	$ 40.21	$ 35.02	$ .30
2006			
9/30/2006	$ 39.16	$ 34.95	$ .30
6/30/2006	$ 36.75	$ 31.33	$ .30
3/31/2006	$ 35.43	$ 30.60	$ .29
12/31/2005	$ 35.27	$ 29.25	$ .29

Note O — Supplementary Information for Oil and Gas Producing Activities (unaudited)

The following supplementary information is presented in accordance with SFAS 69, "Disclosures about Oil and Gas Producing Activities," and related SEC accounting rules. All monetary amounts are expressed in U.S. dollars.

Capitalized Costs Relating to Oil and Gas Producing Activities

	At September 30 2007	At September 30 2006
	(Thousands)	
Proved Properties(1)	$ 1,583,956	$ 1,884,049
Unproved Properties	20,005	41,930
	1,603,961	1,925,979
Less — Accumulated Depreciation, Depletion and Amortization	627,073	929,921
	$ 976,888	$ 996,058

(1) Includes asset retirement costs of $40.9 million and $42.2 million at September 30, 2007 and 2006, respectively.

Costs related to unproved properties are excluded from amortization until proved reserves are found or it is determined that the unproved properties are impaired. All costs related to unproved properties are reviewed quarterly to determine if impairment has occurred. The amount of any impairment is transferred to the pool of capitalized costs being amortized. Following is a summary of costs excluded from amortization at September 30, 2007:

	Total as of September 30, 2007	Year Costs Incurred 2007	2006	2005	Prior
	(Thousands)				
Acquisition Costs	$20,005	$5,957	$12,485	$1,099	$464

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Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities

	Year Ended September 30 2007	2006 (Thousands)	2005
United States			
Property Acquisition Costs:			
Proved	$ 2,621	$ 5,339	$ 287
Unproved	3,210	8,844	1,215
Exploration Costs	26,891	64,087	32,456
Development Costs	113,206	87,738	49,016
Asset Retirement Costs	2,139	10,965	8,051
	148,067	176,973	91,025
Canada — Discontinued Operations			
Property Acquisition Costs:			
Proved	(1,404)	(427)	(1,551)
Unproved	(1,142)	6,492	4,668
Exploration Costs	20,134	20,778	22,943
Development Costs	11,414	14,385	12,198
Asset Retirement Costs	167	279	292
	29,169	41,507	38,550
Total			
Property Acquisition Costs:			
Proved	1,217	4,912	(1,264)
Unproved	2,068	15,336	5,883
Exploration Costs	47,025	84,865	55,399
Development Costs	124,620	102,123	61,214
Asset Retirement Costs	2,306	11,244	8,343
	$ 177,236	$ 218,480	$ 129,575

For the years ended September 30, 2007, 2006 and 2005, the Company spent $30.3 million, $55.6 million and $19.2 million, respectively, developing proved undeveloped reserves.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Results of Operations for Producing Activities

	Year Ended September 30		
	2007	2006	2005
	(Thousands, except per Mcfe amounts)		
United States			
Operating Revenues:			
Natural Gas (includes revenues from sales to affiliates of $325, $106 and $77, respectively)	$ 135,399	$ 152,451	$ 151,004
Oil, Condensate and Other Liquids	189,539	195,050	160,145
Total Operating Revenues(1)	324,938	347,501	311,149
Production/Lifting Costs	48,410	41,354	38,442
Accretion Expense	3,704	2,412	2,220
Depreciation, Depletion and Amortization ($1.97, $1.74 and $1.58 per Mcfe of production)	77,452	66,488	67,097
Income Tax Expense	78,928	88,104	74,110
Results of Operations for Producing Activities (excluding corporate overheads and interest charges)	116,444	149,143	129,280
Canada — Discontinued Operations			
Operating Revenues:			
Natural Gas	39,114	54,819	49,275
Oil, Condensate and Other Liquids	10,313	13,985	12,875
Total Operating Revenues(1)	49,427	68,804	62,150
Production/Lifting Costs	14,846	14,628	12,683
Accretion Expense	249	258	228
Depreciation, Depletion and Amortization ($1.67, $2.95 and $2.36 per Mcfe of production)	12,787	27,439	23,108
Impairment of Oil and Gas Producing Properties(2)	—	104,739	—
Income Tax Expense (Benefit)	3,703	(31,987)	8,577
Results of Operations for Producing Activities (excluding corporate overheads and interest charges)	17,842	(46,273)	17,554

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NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Year Ended September 30		
	2007	2006	2005
	(Thousands, except per Mcfe amounts)		
Total			
Operating Revenues:			
Natural Gas (includes revenues from sales to affiliates of $325, $106 and $77, respectively)	174,513	207,270	200,279
Oil, Condensate and Other Liquids	199,852	209,035	173,020
Total Operating Revenues(1)	374,365	416,305	373,299
Production/Lifting Costs	63,256	55,982	51,125
Accretion Expense	3,953	2,670	2,448
Depreciation, Depletion and Amortization ($1.92, $1.98 and $1.72 per Mcfe of production)	90,239	93,927	90,205
Impairment of Oil and Gas Producing Properties(2)	—	104,739	—
Income Tax Expense	82,631	56,117	82,687
Results of Operations for Producing Activities (excluding corporate overheads and interest charges)	$ 134,286	$ 102,870	$ 146,834

(1) Exclusive of hedging gains and losses. See further discussion in Note F — Financial Instruments.

(2) See discussion of impairment in Note A — Summary of Significant Accounting Policies.

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Reserve Quantity Information

The Company's proved oil and gas reserves are located in the United States. The estimated quantities of proved reserves disclosed in the table below are based upon estimates by qualified Company geologists and engineers and are audited by independent petroleum engineers. Such estimates are inherently imprecise and may be subject to substantial revisions as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions.

	Gas MMcf					
	U. S.					
	Gulf Coast Region	West Coast Region	Appalachian Region	Total U.S.	Canada (Discontinued Operations)	Total Company
Proved Developed and Undeveloped Reserves:						
September 30, 2004	27,734	67,444	78,760	173,938	50,846	224,784
Extensions and Discoveries	17,165	—	5,461	22,626	4,849	27,475
Revisions of Previous Estimates	6,039	7,067	3,733	16,839	(1,600)	15,239
Production	(12,468)	(4,052)	(4,650)	(21,170)	(8,009)	(29,179)
Sales of Minerals in Place	—	—	(179)	(179)	—	(179)
September 30, 2005	38,470	70,459	83,125	192,054	46,086	238,140
Extensions and Discoveries	11,763	1,815	11,132	24,710	6,229	30,939
Revisions of Previous Estimates	679	5,757	(7,776)	(1,340)	(11,096)	(12,436)
Production	(9,110)	(3,880)	(5,108)	(18,098)	(7,673)	(25,771)
Purchases of Minerals in Place	—	1,715	—	1,715	—	1,715
Sales of Minerals in Place	—	—	—	—	(12)	(12)
September 30, 2006	41,802	75,866	81,373	199,041	33,534	232,575
Extensions and Discoveries	3,577	—	29,676	33,253	1,333	34,586
Revisions of Previous Estimates	(9,851)	1,238	1,618	(6,995)	11,634	4,639
Production	(10,356)	(3,929)	(5,555)	(19,840)	(6,426)	(26,266)
Sales of Minerals in Place	(36)	—	(34)	(70)	(40,075)	(40,145)
September 30, 2007	25,136	73,175	107,078	205,389	—	205,389
Proved Developed Reserves:						
September 30, 2004	25,827	53,035	78,760	157,622	46,223	203,845
September 30, 2005	23,108	58,692	83,125	164,925	43,980	208,905
September 30, 2006	32,345	64,196	81,373	177,914	33,534	211,448
September 30, 2007	25,136	66,017	96,674	187,827	—	187,827

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NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Oil Mbbl					
	U.S.					
	Gulf Coast Region	West Coast Region	Appalachian Region	Total U.S.	Canada (Discontinued Operations)	Total Company
Proved Developed and Undeveloped Reserves:						
September 30, 2004	2,080	60,882	147	63,109	2,104	65,213
Extensions and Discoveries	99	—	63	162	204	366
Revisions of Previous Estimates	105	(1,253)	3	(1,145)	(186)	(1,331)
Production	(989)	(2,544)	(36)	(3,569)	(300)	(3,869)
Sales of Minerals in Place	—	—	—	—	(122)	(122)
September 30, 2005	1,295	57,085	177	58,557	1,700	60,257
Extensions and Discoveries	39	172	108	319	128	447
Revisions of Previous Estimates	595	(80)	57	572	101	673
Production	(685)	(2,582)	(69)	(3,336)	(272)	(3,608)
Purchases of Minerals in Place	—	274	—	274	—	274
Sales of Minerals in Place	—	—	—	—	(25)	(25)
September 30, 2006	1,244	54,869	273	56,386	1,632	58,018
Extensions and Discoveries	63	—	281	344	108	452
Revisions of Previous Estimates	851	(6,822)	84	(5,887)	(76)	(5,963)
Production	(717)	(2,403)	(124)	(3,244)	(206)	(3,450)
Sales of Minerals in Place	(6)	—	(7)	(13)	(1,458)	(1,471)
September 30, 2007	1,435	45,644	507	47,586	—	47,586
Proved Developed Reserves:						
September 30, 2004	2,061	38,631	148	40,840	2,104	42,944
September 30, 2005	1,229	41,701	177	43,107	1,700	44,807
September 30, 2006	1,217	42,522	273	44,012	1,632	45,644
September 30, 2007	1,435	36,509	483	38,427	—	38,427

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The Company cautions that the following presentation of the standardized measure of discounted future net cash flows is intended to be neither a measure of the fair market value of the Company's oil and gas properties, nor an estimate of the present value of actual future cash flows to be obtained as a result of their development and production. It is based upon subjective estimates of proved reserves only and attributes no value to categories of reserves other than proved reserves, such as probable or possible reserves, or to unproved acreage. Furthermore, it is based on year-end prices and costs adjusted only for existing contractual changes, and it assumes an arbitrary discount rate of 10%. Thus, it gives no effect to future price and cost changes certain to occur under widely fluctuating political and economic conditions.

The standardized measure is intended instead to provide a means for comparing the value of the Company's proved reserves at a given time with those of other oil- and gas-producing companies than is provided by a simple comparison of raw proved reserve quantities.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Year Ended September 30 2007	2006 (Thousands)	2005
United States			
Future Cash Inflows	$ 4,879,496	$ 3,911,059	$ 6,138,522
Less:			
Future Production Costs	872,536	758,258	777,417
Future Development Costs	229,987	205,497	188,795
Future Income Tax Expense at Applicable Statutory Rate	1,423,707	1,019,307	1,868,548
Future Net Cash Flows	2,353,266	1,927,997	3,303,762
Less:			
10% Annual Discount for Estimated Timing of Cash Flows	1,292,804	1,066,338	1,812,230
Standardized Measure of Discounted Future Net Cash Flows	1,060,462	861,659	1,491,532
Canada — Discontinued Operations			
Future Cash Inflows	—	197,227	601,210
Less:			
Future Production Costs	—	92,234	136,338
Future Development Costs	—	11,520	12,197
Future Income Tax Expense at Applicable Statutory Rate	—	(151)	137,524
Future Net Cash Flows	—	93,624	315,151
Less:			
10% Annual Discount for Estimated Timing of Cash Flows	—	19,375	108,508
Standardized Measure of Discounted Future Net Cash Flows	—	74,249	206,643
Total			
Future Cash Inflows	4,879,496	4,108,286	6,739,732
Less:			
Future Production Costs	872,536	850,492	913,755
Future Development Costs	229,987	217,017	200,992
Future Income Tax Expense at Applicable Statutory Rate	1,423,707	1,019,156	2,006,072
Future Net Cash Flows	2,353,266	2,021,621	3,618,913
Less:			
10% Annual Discount for Estimated Timing of Cash Flows	1,292,804	1,085,713	1,920,738
Standardized Measure of Discounted Future Net Cash Flows	$ 1,060,462	$ 935,908	$ 1,698,175

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The principal sources of change in the standardized measure of discounted future net cash flows were as follows:

	Year Ended September 30		
	2007	2006	2005
		(Thousands)	
United States			
Standardized Measure of Discounted Future Net Cash Flows at Beginning of Year	$ 861,659	$ 1,491,532	$ 935,369
Sales, Net of Production Costs	(276,529)	(306,147)	(272,707)
Net Changes in Prices, Net of Production Costs	539,895	(941,545)	1,093,353
Purchases of Minerals in Place	—	7,607	—
Sales of Minerals in Place	484	—	(762)
Extensions and Discoveries	98,751	66,975	100,102
Changes in Estimated Future Development Costs	(83,199)	(83,750)	(89,805)
Previously Estimated Development Costs Incurred	58,710	67,048	25,038
Net Change in Income Taxes at Applicable Statutory Rate	(174,920)	404,176	(362,956)
Revisions of Previous Quantity Estimates	(140,203)	4,850	25,055
Accretion of Discount and Other	175,814	150,913	38,845
Standardized Measure of Discounted Future Net Cash Flows at End of Year	1,060,462	861,659	1,491,532
Canada — Discontinued Operations			
Standardized Measure of Discounted Future Net Cash Flows at Beginning of Year	74,249	206,643	110,730
Sales, Net of Production Costs	(34,581)	(54,176)	(49,467)
Net Changes in Prices, Net of Production Costs	35,628	(180,216)	174,985
Purchases of Minerals in Place	—	—	—
Sales of Minerals in Place	(151,236)	(238)	(3,751)
Extensions and Discoveries	6,908	10,369	31,028
Changes in Estimated Future Development Costs	5,722	(3,282)	(11,007)
Previously Estimated Development Costs Incurred	5,798	4,450	12,032
Net Change in Income Taxes at Applicable Statutory Rate	(10,075)	82,966	(51,541)
Revisions of Previous Quantity Estimates	34,998	(15,478)	(5,990)
Accretion of Discount and Other	32,589	23,211	(376)
Standardized Measure of Discounted Future Net Cash Flows at End of Year	—	74,249	206,643

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NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Year Ended September 30 2007	2006 (Thousands)	2005
Total			
Standardized Measure of Discounted Future			
Net Cash Flows at Beginning of Year	935,908	1,698,175	1,046,099
Sales, Net of Production Costs	(311,110)	(360,323)	(322,174)
Net Changes in Prices, Net of Production Costs	575,523	(1,121,761)	1,268,338
Purchases of Minerals in Place	—	7,607	—
Sales of Minerals in Place	(150,752)	(238)	(4,513)
Extensions and Discoveries	105,659	77,344	131,130
Changes in Estimated Future Development Costs	(77,477)	(87,032)	(100,812)
Previously Estimated Development Costs Incurred	64,508	71,498	37,070
Net Change in Income Taxes at Applicable Statutory Rate	(184,995)	487,142	(414,497)
Revisions of Previous Quantity Estimates	(105,205)	(10,628)	19,065
Accretion of Discount and Other	208,403	174,124	38,469
Standardized Measure of Discounted Future Net Cash Flows at End of Year	$ 1,060,462	$ 935,908	$ 1,698,175

Schedule II — Valuation and Qualifying Accounts

Description	Balance at Beginning of Period	Additions Charged to Costs and Expenses	Additions Charged to Other Accounts (Thousands)	Deductions(3)	Balance at End of Period
Year Ended September 30, 2007					
Allowance for Uncollectible Accounts	$ 31,427	$ 27,652	$ 1,414(1)	$ 31,839	$ 28,654
Year Ended September 30, 2006					
Allowance for Uncollectible Accounts	$ 26,940	$ 29,088	$ 907(1)	$ 25,508	$ 31,427
Deferred Tax Valuation Allowance	$ 2,877	$ (2,877)	$ —	$ —	$ —
Year Ended September 30, 2005					
Allowance for Uncollectible Accounts	$ 17,440	$ 31,113	$ 2,480(2)	$ 24,093	$ 26,940
Deferred Tax Valuation Allowance	$ 2,877	$ —	$ —	$ —	$ 2,877

(1) Represents the discount on accounts receivable purchased in accordance with the Utility segment's 2005 New York rate agreement.

(2) Represents amounts reclassified from regulatory asset and regulatory liability accounts under various rate settlements ($4.5 million). Also includes amounts removed with the sale of U.E. (-$2.02 million).

(3) Amounts represent net accounts receivable written-off.

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Item 9 ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure***

None

Item 9A ***Controls and Procedures***

Evaluation of Disclosure Controls and Procedures

The term "disclosure controls and procedures" is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act. These rules refer to the controls and other procedures of a company that are designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed is accumulated and communicated to the company's management, including its principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure. The Company's management, including the Chief Executive Officer and Principal Financial Officer, evaluated the effectiveness of the Company's disclosure controls and procedures as of the end of the period covered by this report. Based upon that evaluation, the Company's Chief Executive Officer and Principal Financial Officer concluded that the Company's disclosure controls and procedures were effective as of September 30, 2007.

Management's Report on Internal Control over Financial Reporting

The management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act. The Company's internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and preparation of financial statements for external purposes in accordance with GAAP. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements.

The Company's management assessed the effectiveness of the Company's internal control over financial reporting as of September 30, 2007. In making this assessment, management used the framework and criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control — Integrated Framework*. Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as of September 30, 2007.

PricewaterhouseCoopers LLP, the independent registered public accounting firm that audited the Company's consolidated financial statements included in this Annual Report on Form 10-K, has issued a report on the effectiveness of the Company's internal control over financial reporting as of September 30, 2007. The report appears in Part II, Item 8 of this Annual Report on Form 10-K.

Changes in Internal Control over Financial Reporting

There were no changes in the Company's internal control over financial reporting that occurred during the quarter ended September 30, 2007 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Item 9B ***Other Information***

None

PART III

Item 10 ***Directors, Executive Officers and Corporate Governance***

The information required by this item concerning the directors of the Company and corporate governance is omitted pursuant to Instruction G of Form 10-K since the Company's definitive Proxy Statement for its 2008

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Annual Meeting of Stockholders will be filed with the SEC not later than 120 days after September 30, 2007. The information concerning directors is set forth in the definitive Proxy Statement under the headings entitled "Nominees for Election as Directors for Three-Year Terms to Expire in 2011," "Directors Whose Terms Expire in 2010," "Directors Whose Terms Expire in 2009," and "Section 16(a) Beneficial Ownership Reporting Compliance" and is incorporated herein by reference. The information concerning corporate governance is set forth in the definitive Proxy Statement under the heading entitled "Meetings of the Board of Directors and Standing Committees" and is incorporated herein by reference. Information concerning the Company's executive officers can be found in Part I, Item 1, of this report.

The Company has adopted a Code of Business Conduct and Ethics that applies to the Company's directors, officers and employees and has posted such Code of Business Conduct and Ethics on the Company's website, www.nationalfuelgas.com, together with certain other corporate governance documents. Copies of the Company's Code of Business Conduct and Ethics, charters of important committees, and Corporate Governance Guidelines will be made available free of charge upon written request to Investor Relations, National Fuel Gas Company, 6363 Main Street, Williamsville, New York 14221.

The Company intends to satisfy the disclosure requirement under Item 5.05 of Form 8-K regarding an amendment to, or a waiver from, a provision of its code of ethics that applies to the Company's principal executive officer, principal financial officer, principal accounting officer or controller, or persons performing similar functions, and that relates to any element of the code of ethics definition enumerated in paragraph (b) of Item 406 of the SEC's Regulation S-K, by posting such information on its website, www.nationalfuelgas.com.

Item 11 *Executive Compensation*

The information required by this item is omitted pursuant to Instruction G of Form 10-K since the Company's definitive Proxy Statement for its 2008 Annual Meeting of Stockholders will be filed with the SEC not later than 120 days after September 30, 2007. The information concerning executive compensation is set forth in the definitive Proxy Statement under the headings "Executive Compensation" and "Compensation Committee Interlocks and Insider Participation" and, excepting the "Report of the Compensation Committee," is incorporated herein by reference.

Item 12 *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters*

Equity Compensation Plan Information

The information required by this item is omitted pursuant to Instruction G of Form 10-K since the Company's definitive Proxy Statement for its 2008 Annual Meeting of Stockholders will be filed with the SEC not later than 120 days after September 30, 2007. The equity compensation plan information is set forth in the definitive Proxy Statement under the heading "Equity Compensation Plan Information" and is incorporated herein by reference.

Security Ownership and Changes in Control

(a) Security Ownership of Certain Beneficial Owners

The information required by this item is omitted pursuant to Instruction G of Form 10-K since the Company's definitive Proxy Statement for its 2008 Annual Meeting of Stockholders will be filed with the SEC not later than 120 days after September 30, 2007. The information concerning security ownership of certain beneficial owners is set forth in the definitive Proxy Statement under the heading "Security Ownership of Certain Beneficial Owners and Management" and is incorporated herein by reference.

(b) Security Ownership of Management

The information required by this item is omitted pursuant to Instruction G of Form 10-K since the Company's definitive Proxy Statement for its 2008 Annual Meeting of Stockholders will be filed with the SEC not later than 120 days after September 30, 2007. The information concerning security ownership of

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management is set forth in the definitive Proxy Statement under the heading "Security Ownership of Certain Beneficial Owners and Management" and is incorporated herein by reference.

(c) Changes in Control

None

Item 13 ***Certain Relationships and Related Transactions, and Director Independence***

The information required by this item is omitted pursuant to Instruction G of Form 10-K since the Company's definitive Proxy Statement for its 2008 Annual Meeting of Stockholders will be filed with the SEC not later than 120 days after September 30, 2007. The information regarding certain relationships and related transactions is set forth in the definitive Proxy Statement under the headings "Compensation Committee Interlocks and Insider Participation" and "Related Person Transactions" and is incorporated herein by reference. The information regarding director independence is set forth in the definitive Proxy Statement under the heading "Director Independence" and is incorporated herein by reference.

Item 14 ***Principal Accountant Fees and Services***

The information required by this item is omitted pursuant to Instruction G of Form 10-K since the Company's definitive Proxy Statement for its 2008 Annual Meeting of Stockholders will be filed with the SEC not later than 120 days after September 30, 2007. The information concerning principal accountant fees and services is set forth in the definitive Proxy Statement under the heading "Audit Fees" and is incorporated herein by reference.

PART IV

Item 15 ***Exhibits and Financial Statement Schedules***

(a)1. Financial Statements

Financial statements filed as part of this report are listed in the index included in Item 8 of this Form 10-K, and reference is made thereto.

(a)2. Financial Statement Schedules

Financial statement schedules filed as part of this report are listed in the index included in Item 8 of this Form 10-K, and reference is made thereto.

(a)3. Exhibits

Exhibit Number	Description of Exhibits
3(i)	Articles of Incorporation:
•	Restated Certificate of Incorporation of National Fuel Gas Company dated September 21, 1998 (Exhibit 3.1, Form 10-K for fiscal year ended September 30, 1998 in File No. 1-3880)
•	Certificate of Amendment of Restated Certificate of Incorporation (Exhibit 3(ii), Form 8-K dated March 14, 2005 in File No. 1-3880)
3(ii)	By-Laws:
•	National Fuel Gas Company By-Laws as amended June 7, 2007 (Exhibit 3.1, Form 8-K dated June 8, 2007 in File No. 1-3880)
4	Instruments Defining the Rights of Security Holders, Including Indentures:
•	Indenture, dated as of October 15, 1974, between the Company and The Bank of New York (formerly Irving Trust Company) (Exhibit 2(b) in File No. 2-51796)
•	Third Supplemental Indenture, dated as of December 1, 1982,to Indenture dated as of October 15, 1974, between the Company and The Bank of New York (formerly Irving Trust Company) (Exhibit 4(a)(4) in File No. 33-49401)

Docket No. RP09-_____-000
Exhibit No. HIO-74
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Exhibit Number	Description of Exhibits
•	Eleventh Supplemental Indenture, dated as of May 1, 1992, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York (formerly Irving Trust Company) (Exhibit 4(b), Form 8-K dated February 14, 1992 in File No. 1-3880)
•	Twelfth Supplemental Indenture, dated as of June 1, 1992, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York (formerly Irving Trust Company) (Exhibit 4(c), Form 8-K dated June 18, 1992 in File No. 1-3880)
•	Thirteenth Supplemental Indenture, dated as of March 1, 1993, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York (formerly Irving Trust Company) (Exhibit 4(a)(14) in File No. 33-49401)
•	Fourteenth Supplemental Indenture, dated as of July 1, 1993,to Indenture dated as of October 15, 1974, between the Company and The Bank of New York (formerly Irving Trust Company) (Exhibit 4.1, Form 10-K for fiscal year ended September 30, 1993 in File No. 1-3880)
•	Fifteenth Supplemental Indenture, dated as of September 1, 1996, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York (formerly Irving Trust Company) (Exhibit 4.1, Form 10-K for fiscal year ended September 30, 1996 in File No. 1-3880)
•	Indenture dated as of October 1, 1999, between the Company and The Bank of New York (Exhibit 4.1, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880)
•	Officers Certificate Establishing Medium-Term Notes, dated October 14, 1999 (Exhibit 4.2, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880)
•	Officers Certificate establishing 5.25% Notes due 2013, dated February 18, 2003 (Exhibit 4, Form 10-Q for the quarterly period ended March 31, 2003 in File No. 1-3880)
4.1	Amended and Restated Rights Agreement, dated as of September 1, 2007, between the Company and The Bank of New York
10	Material Contracts:
	Contracts other than compensatory plans, contracts or arrangements:
•	Form of Indemnification Agreement, dated September 2006, between the Company and each Director (Exhibit 10.1, Form 8-K dated September 18, 2006 in File No. 1-3880)
•	Credit Agreement, dated as of August 19, 2005, among the Company, the Lenders Party Thereto and JPMorgan Chase Bank, N.A., as Administrative Agent (Exhibit 10.1, Form 10-K for fiscal year ended September 30, 2005 in File No. 1-3880)
	Compensatory plans, contracts or arrangements:
10.1	Form of Employment Continuation and Noncompetition Agreement among the Company, a subsidiary of the Company and each of Philip C. Ackerman, Anna Marie Cellino, Paula M. Ciprich, Donna L. DeCarolis, John R. Pustulka, James D. Ramsdell, David F. Smith and Ronald J. Tanski
10.2	Employment Continuation and Noncompetition Agreement, dated as of September 20, 2007, among the Company, Seneca Resources Corporation and Matthew D. Cabell
•	Letter Agreement between the Company and Matthew D. Cabell, dated November 17, 2006 (Exhibit 10.1, Form 10-Q for the quarterly period ended December 31, 2006 in File No. 1-3880)
•	National Fuel Gas Company 1993 Award and Option Plan, dated February 18, 1993 (Exhibit 10.1, Form 10-Q for the quarterly period ended March 31, 1993 in File No. 1-3880)
•	Amendment to National Fuel Gas Company 1993 Award and Option Plan, dated October 27, 1995 (Exhibit 10.8, Form 10-K for fiscal year ended September 30, 1995 in File No. 1-3880)
•	Amendment to National Fuel Gas Company 1993 Award and Option Plan, dated December 11, 1996 (Exhibit 10.8, Form 10-K for fiscal year ended September 30, 1996 in File No. 1-3880)
•	Amendment to National Fuel Gas Company 1993 Award and Option Plan, dated December 18, 1996 (Exhibit 10, Form 10-Q for the quarterly period ended December 31, 1996 in File No. 1-3880)
•	National Fuel Gas Company 1993 Award and Option Plan, amended through June 14, 2001 (Exhibit 10.1, Form 10-K for fiscal year ended September 30, 2001 in File No. 1-3880)

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Exhibit Number	Description of Exhibits
•	National Fuel Gas Company 1993 Award and Option Plan, amended through September 8, 2005 (Exhibit 10.2, Form 10-K for fiscal year ended September 30, 2005 in File No. 1-3880)
•	Administrative Rules with Respect to At Risk Awards under the 1993 Award and Option Plan (Exhibit 10.14, Form 10-K for fiscal year ended September 30, 1996 in File No. 1-3880)
•	National Fuel Gas Company 1997 Award and Option Plan, as amended and restated as of February 15, 2007 (Exhibit 10.2, Form 10-Q for the quarterly period ended March 31, 2007 in File No. 1-3880)
•	Form of Award Notice under National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.1, Form 8-K dated March 28, 2005 in File No. 1-3880)
•	Form of Award Notice under National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.1, Form 8-K dated May 16, 2006 in File No. 1-3880)
•	Form of Restricted Stock Award Notice under National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 2006 in File No. 1-3880)
•	Form of Stock Option Award Notice under National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.3, Form 10-Q for the quarterly period ended December 31, 2006 in File No. 1-3880)
•	Administrative Rules with Respect to At Risk Awards under the 1997 Award and Option Plan amended and restated as of September 8, 2005 (Exhibit 10.4, Form 10-K for fiscal year ended September 30, 2005 in File No. 1-3880)
•	National Fuel Gas Company 2007 Annual At Risk Compensation Incentive Program (Exhibit 10.1, Form 10-Q for the quarterly period ended March 31, 2007 in File No. 1-3880)
•	Description of performance goals for Chief Executive Officer under the Company's Annual At Risk Compensation Incentive Program (Exhibit 10, Form 10-Q for the quarterly period ended December 31, 2004 in File No. 1-3880)
•	Description of performance goals for Chief Executive Officer under the Company's Annual At Risk Compensation Incentive Program (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 2005 in File No. 1-3880)
•	Description of performance goals for certain executive officers under the Company's Annual At Risk Compensation Incentive Program (Exhibit 10.8, Form 10-Q for the quarterly period ended December 31, 2006 in File No. 1-3880)
•	Administrative Rules of the Compensation Committee of the Board of Directors of National Fuel Gas Company, as amended and restated effective December 6, 2006 (Exhibit 10.6, Form 10-Q for the quarterly period ended December 31, 2006 in File No. 1-3880)
•	National Fuel Gas Company Deferred Compensation Plan, as amended and restated through May 1, 1994 (Exhibit 10.7, Form 10-K for fiscal year ended September 30, 1994 in File No. 1-3880)
•	Amendment to National Fuel Gas Company Deferred Compensation Plan, dated September 27, 1995 (Exhibit 10.9, Form 10-K for fiscal year ended September 30, 1995 in File No. 1-3880)
•	Amendment to National Fuel Gas Company Deferred Compensation Plan, dated September 19, 1996 (Exhibit 10.10, Form 10-K for fiscal year ended September 30, 1996 in File No. 1-3880)
•	National Fuel Gas Company Deferred Compensation Plan, as amended and restated through March 20, 1997 (Exhibit 10.3,Form 10-K for fiscal year ended September 30, 1997 in File No. 1-3880)
•	Amendment to National Fuel Gas Company Deferred Compensation Plan, dated June 16, 1997 (Exhibit 10.4, Form 10-K for fiscal year ended September 30, 1997 in File No. 1-3880)
•	Amendment No. 2 to the National Fuel Gas Company Deferred Compensation Plan, dated March 13, 1998 (Exhibit 10.1, Form 10-K for fiscal year ended September 30, 1998 in File No. 1-3880)
•	Amendment to the National Fuel Gas Company Deferred Compensation Plan, dated February 18, 1999 (Exhibit 10.1,Form 10-Q for the quarterly period ended March 31, 1999 in File No. 1-3880)
•	Amendment to National Fuel Gas Company Deferred Compensation Plan, dated June 15, 2001 (Exhibit 10.3, Form 10-K for fiscal year ended September 30, 2001 in File No. 1-3880)
•	Amendment to the National Fuel Gas Company Deferred Compensation Plan, dated October 21, 2005 (Exhibit 10.5, Form 10-K for fiscal year ended September 30, 2005 in File No. 1-3880)

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Exhibit Number	Description of Exhibits
•	Form of Letter Regarding Deferred Compensation Plan and Internal Revenue Code Section 409A, dated July 12, 2005 (Exhibit 10.6, Form 10-K for fiscal year ended September 30, 2005 in File No. 1-3880)
•	National Fuel Gas Company Tophat Plan, effective March 20, 1997 (Exhibit 10, Form 10-Q for the quarterly period ended June 30, 1997 in File No. 1-3880)
•	Amendment No. 1 to National Fuel Gas Company Tophat Plan, dated April 6, 1998 (Exhibit 10.2, Form 10-K for fiscal year ended September 30, 1998 in File No. 1-3880)
•	Amendment No. 2 to National Fuel Gas Company Tophat Plan, dated December 10, 1998 (Exhibit 10.1, Form 10-Q for the quarterly period ended December 31, 1998 in File No. 1-3880)
•	Form of Letter Regarding Tophat Plan and Internal Revenue Code Section 409A, dated July 12, 2005 (Exhibit 10.7, Form 10-K for fiscal year ended September 30, 2005 in File No. 1-3880)
•	National Fuel Gas Company Tophat Plan, Amended and Restated December 7, 2005 (Exhibit 10.1, Form 10-Q for the quarterly period ended December 31, 2005 in File No. 1-3880)
10.3	National Fuel Gas Company Tophat Plan, as amended September 20, 2007
•	Amended and Restated Split Dollar Insurance and Death Benefit Agreement, dated September 17, 1997 between the Company and Philip C. Ackerman (Exhibit 10.5, Form 10-K for fiscal year ended September 30, 1997 in File No. 1-3880)
•	Amendment Number 1 to Amended and Restated Split Dollar Insurance and Death Benefit Agreement by and between the Company and Philip C. Ackerman, dated March 23, 1999 (Exhibit 10.3, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880)
•	Amended and Restated Split Dollar Insurance and Death Benefit Agreement, dated September 15, 1997, between the Company and Dennis J. Seeley (Exhibit 10.9, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880)
•	Amendment Number 1 to Amended and Restated Split Dollar Insurance and Death Benefit Agreement by and between the Company and Dennis J. Seeley, dated March 29, 1999 (Exhibit 10.10, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880)
•	Split Dollar Insurance and Death Benefit Agreement, dated September 15, 1997, between the Company and David F. Smith (Exhibit 10.13, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880)
•	Amendment Number 1 to Split Dollar Insurance and Death Benefit Agreement by and between the Company and David F. Smith, dated March 29, 1999 (Exhibit 10.14, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880)
•	National Fuel Gas Company Parameters for Executive Life Insurance Plan (Exhibit 10.1, Form 10-K for fiscal year ended September 30, 2004 in File No. 1-3880)
•	National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan as amended and restated through November 1, 1995 (Exhibit 10.10, Form 10-K for fiscal year ended September 30, 1995 in File No. 1-3880)
•	Amendments to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, dated September 18, 1997 (Exhibit 10.9, Form 10-K for fiscal year ended September 30, 1997 in File No. 1-3880)
•	Amendments to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, dated December 10, 1998 (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 1998 in File No. 1-3880)
•	Amendments to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, effective September 16, 1999 (Exhibit 10.15, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880)
•	Amendment to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, effective September 5, 2001 (Exhibit 10.4, Form 10-K/A for fiscal year ended September 30, 2001, in File No. 1-3880)

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Exhibit Number	Description of Exhibits
•	National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, Amended and Restated as of January 1, 2007 (Exhibit 10.5, Form 10-Q for the quarterly period ended December 31, 2006 in File No. 1-3880)
10.4	National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, Amended and Restated as of September 20, 2007
•	National Fuel Gas Company and Participating Subsidiaries 1996 Executive Retirement Plan Trust Agreement (II), dated May 10, 1996 (Exhibit 10.13, Form 10-K for fiscal year ended September 30, 1996 in File No. 1-3880)
•	National Fuel Gas Company Participating Subsidiaries Executive Retirement Plan 2003 Trust Agreement(I), dated September 1, 2003 (Exhibit 10.2, Form 10-K for fiscal year ended September 30, 2004 in File No. 1-3880)
•	National Fuel Gas Company Performance Incentive Program (Exhibit 10.1, Form 8-K dated June 3, 2005 in File No. 1-3880)
•	Excerpts of Minutes from the National Fuel Gas Company Board of Directors Meeting of March 20, 1997 regarding the Retainer Policy for Non-Employee Directors (Exhibit 10.11, Form 10-K for fiscal year ended September 30, 1997 in File No. 1-3880)
10.5	Amended and Restated Retirement Benefit Agreement for David F. Smith, dated September 20, 2007,among the Company, National Fuel Gas Supply Corporation and David F. Smith
•	Description of performance goals for certain executive officers (Exhibit 10.1, Form 10-Q for the quarterly period ended March 31, 2005 in File No. 1-3880)
•	Description of bonuses awarded to executive officer (Exhibit 10.1, Form 10-Q for the quarterly period ended March 31, 2006 in File No. 1-3880)
•	Description of performance goals for certain executive officers (Exhibit 10.2, Form 10-Q for the quarterly period ended March 31, 2006 in File No. 1-3880)
•	Noncompete and Restrictive Covenant Agreement, dated February 1, 2006, between the Company and Dennis J. Seeley (Exhibit 10.3, Form 10-Q for the quarterly period ended March 31, 2006 in File No. 1-3880)
•	Description of salaries of certain executive officers (Exhibit 10.4, Form 10-Q for the quarterly period ended March 31, 2006 in File No. 1-3880)
•	Description of assignment of interests in certain life insurance policies (Exhibit 10.1, Form 10-Q for the quarterly period ended June 30, 2006 in File No. 1-3880)
•	Description of long-term performance incentives under the National Fuel Gas Company Performance Incentive Program (Exhibit 10.2, Form 10-Q for the quarterly period ended June 30, 2006 in File No. 1-3880)
•	Description of long-term performance incentives under the National Fuel Gas Company Performance Incentive Program (Exhibit 10.7, Form 10-Q for the quarterly period ended December 31, 2006 in File No. 1-3880)
•	Description of agreement between the Company and Philip C. Ackerman regarding death benefit (Exhibit 10.3, Form 10-Q for the quarterly period ended June 30, 2006 in File No. 1-3880)
•	Agreement, dated September 24, 2006, between the Company and Philip C. Ackerman regarding death benefit (Exhibit 10.1, Form 10-K for the fiscal year ended September 30, 2006 in File No. 1-3880)
•	Retirement Agreement, dated July 1, 2006, between the Company and James A. Beck (Exhibit 10.4, Form 10-Q for the quarterly period ended June 30, 2006 in File No. 1-3880)
•	Contract for Consulting Services, dated July 1, 2006, between the Company and James A. Beck (Exhibit 10.5, Form 10-Q for the quarterly period ended June 30, 2006 in File No. 1-3880)
12	Statements regarding Computation of Ratios: Ratio of Earnings to Fixed Charges for the fiscal years ended September 30, 2003 through 2007
21	Subsidiaries of the Registrant
23	Consents of Experts:

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Exhibit Number	Description of Exhibits
23.1	Consent of Netherland, Sewell & Associates, Inc. regarding Seneca Resources Corporation
23.2	Consent of Independent Registered Public Accounting Firm
31	Rule 13a-14(a)/15d-14(a) Certifications:
31.1	Written statements of Chief Executive Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Exchange Act
31.2	Written statements of Principal Financial Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Exchange Act
32	Certifications pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99	Additional Exhibits:
99.1	Report of Netherland, Sewell & Associates, Inc. regarding Seneca Resources Corporation
99.2	Company Maps
•	Incorporated herein by reference as indicated.
	All other exhibits are omitted because they are not applicable or the required information is shown elsewhere in this Annual Report on Form 10-K
••	In accordance with Item 601(b)(32)(ii) of Regulation S-K and SEC Release Nos. 33-8238 and 34-47986, Final Rule: Management's Reports on Internal Control Over Financial Reporting and Certification of Disclosure in Exchange Act Periodic Reports, the material contained in Exhibit 32 is "furnished" and not deemed "filed" with the SEC and is not to be incorporated by reference into any filing of the Registrant under the Securities Act of 1933 or the Exchange Act, whether made before or after the date hereof and irrespective of any general incorporation language contained in such filing, except to the extent that the Registrant specifically incorporates it by reference

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Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

National Fuel Gas Company
(Registrant)

By /s/ P. C. Ackerman
P. C. Ackerman
Chairman of the Board and Chief Executive Officer

Date: November 29, 2007

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	
/s/ P. C. Ackerman P. C. Ackerman	Chairman of the Board, Chief Executive Officer and Director	Date: November 29, 2007
/s/ R. T. Brady R. T. Brady	Director	Date: November 29, 2007
/s/ R. D. Cash R. D. Cash	Director	Date: November 29, 2007
/s/ S. E. Ewing S. E. Ewing	Director	Date: November 29, 2007
/s/ R. E. Kidder R. E. Kidder	Director	Date: November 29, 2007
/s/ C. G. Matthews C. G. Matthews	Director	Date: November 29, 2007
/s/ G. L. Mazanec G. L. Mazanec	Director	Date: November 29, 2007
/s/ R. G. Reiten R. G. Reiten	Director	Date: November 29, 2007
/s/ J. F. Riordan J. F. Riordan	Director	Date: November 29, 2007
/s/ D. F. Smith D. F. Smith	President, Chief Operating Officer and Director	Date: November 29, 2007

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Signature	Title	
/s/ R. J. Tanski R. J. Tanski	Treasurer and Principal Financial Officer	Date: November 29, 2007
/s/ K. M. Camiolo K. M. Camiolo	Controller and Principal Accounting Officer	Date: November 29, 2007

OKS 10-Q 9/30/2008

Section 1: 10-Q (FORM 10-Q)

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

X Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the quarterly period ended September 30, 2008
OR
__ Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the transition period from _____ to _____.

Commission file number **1-12202**

ONEOK PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**93-1120873** (I.R.S. Employer Identification No.)
100 West Fifth Street, Tulsa, OK (Address of principal executive offices)	**74103** (Zip Code)

Registrant's telephone number, including area code **(918) 588-7000**

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes X No __

Indicate by checkmark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definition of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.
Large accelerated filer X Accelerated filer __ Non-accelerated filer __ Smaller reporting company__

Indicate by checkmark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes __ No X

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Class	Outstanding at October 31, 2008
Common units	54,426,087 units
Class B units	36,494,126 units

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ONEOK PARTNERS, L.P.
QUARTERLY REPORT ON FORM 10-Q

As used in this Quarterly Report on Form 10-Q, "we," "our," "us" or the "Partnership" refers to ONEOK Partners, L.P. and its subsidiary, ONEOK Partners Intermediate Limited Partnership and its subsidiaries, unless the context indicates otherwise.

The statements in this Quarterly Report on Form 10-Q that are not historical information, including statements concerning plans and objectives of management for future operations, economic performance or related assumptions, are forward-looking statements. Forward-looking statements may include words such as "anticipate," "estimate," "expect," "project," "intend," "plan," "believe," "should," "goal," "forecast," "could," "may," "continue," "might," "potential," "scheduled" and other words and terms of similar meaning. Although we believe that our expectations regarding future events are based on reasonable assumptions, we can give no assurance that our goals will be achieved. Important factors that could cause actual results to differ materially from those in the forward-looking statements are described under Part I, Item 2, Management's Discussion and Analysis of Financial Condition and Results of Operations, "Forward-Looking Statements" and Part II, Item 1A, "Risk Factors" in this Quarterly Report on Form 10-Q and under Part I, Item 1A, "Risk Factors," in our Annual Report on Form 10-K for the year ended December 31, 2007.

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GLOSSARY

The abbreviations, acronyms and industry terminology used in this Quarterly Report on Form 10-Q are defined as follows:

AFUDC	Allowance for funds used during construction
ARB	Accounting Research Bulletin
Bbl	Barrels, 1 barrel is equivalent to 42 United States gallons
Bbl/d	Barrels per day
BBtu/d	Billion British thermal units per day
Btu	British thermal units, a measure of the amount of heat required to raise the temperature of one pound of water one degree Fahrenheit
Bushton Plant	Bushton Gas Processing Plant
EITF	Emerging Issues Task Force
Exchange Act	Securities Exchange Act of 1934, as amended
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FIN	FASB Interpretation
Fort Union Gas Gathering	Fort Union Gas Gathering, L.L.C.
GAAP	Generally Accepted Accounting Principles in the United States
Guardian Pipeline	Guardian Pipeline, L.L.C.
Heartland	Heartland Pipeline Company
KCC	Kansas Corporation Commission
KDHE	Kansas Department of Health and Environment
LIBOR	London Interbank Offered Rate
MBbl	Thousand barrels
MBbl/d	Thousand barrels per day
Midwestern Gas Transmission	Midwestern Gas Transmission Company
MMBtu	Million British thermal units
MMBtu/d	Million British thermal units per day
MMcf/d	Million cubic feet per day
Moody’s	Moody’s Investors Service, Inc.
NBP Services	NBP Services, LLC, a subsidiary of ONEOK
NGL(s)	Natural gas liquid(s)
Northern Border Pipeline	Northern Border Pipeline Company
NYMEX	New York Mercantile Exchange
OBPI	ONEOK Bushton Processing Inc.
OCC	Oklahoma Corporation Commission
OkTex Pipeline	OkTex Pipeline Company, L.L.C.
ONEOK	ONEOK, Inc.
ONEOK Partners GP	ONEOK Partners GP, L.L.C., a wholly owned subsidiary of ONEOK, Inc. and our sole general partner
OPIS	Oil Price Information Service
Overland Pass Pipeline Company	Overland Pass Pipeline Company LLC
Partnership Agreement	Third Amended and Restated Agreement of Limited Partnership of ONEOK Partners, L.P., as amended
S&P	Standard & Poor’s Rating Group
SEC	Securities and Exchange Commission
Statement	Statement of Financial Accounting Standards

AVAILABLE INFORMATION

You can access financial and other information, including news releases, webcasts and presentations, environmental safety and health information, and corporate governance information at our website at www.oneokpartners.com. We also make available on our website copies of our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, amendments to those reports filed or furnished to the SEC pursuant to Section 13(a) or 15(d) of the Exchange Act and reports of holdings of our securities filed by our officers and directors under Section 16 of the Exchange Act as soon as reasonably practicable after filing such material electronically or otherwise furnishing it to the SEC.

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PART I—FINANCIAL INFORMATION
ITEM 1. FINANCIAL STATEMENTS
ONEOK Partners, L.P. and Subsidiaries
CONSOLIDATED STATEMENTS OF INCOME

	Three Months Ended September 30,		Nine Months Ended September 30,	
(Unaudited)	**2008**	**2007**	**2008**	**2007**
	(Thousands of dollars, except per unit amounts)			
Revenues	**$2,241,107**	$1,410,257	**$6,444,034**	$3,954,245
Cost of sales and fuel	**1,915,707**	1,196,373	**5,569,176**	3,317,421
Net Margin	**325,400**	213,884	**874,858**	636,824
Operating Expenses				
Operations and maintenance	**86,456**	71,470	**243,929**	212,517
Depreciation and amortization	**30,408**	28,800	**90,383**	84,326
General taxes	**11,032**	8,609	**28,799**	24,866
Total Operating Expenses	**127,896**	108,879	**363,111**	321,709
Gain (Loss) on Sale of Assets	**22**	111	**50**	1,935
Operating Income	**197,526**	105,116	**511,797**	317,050
Equity earnings from investments (Note J)	**29,412**	22,162	**74,805**	64,975
Allowance for equity funds used during construction	**15,616**	3,691	**35,788**	6,686
Other income	**990**	905	**3,724**	4,870
Other expense	**(5,784)**	(125)	**(7,951)**	(636)
Interest expense	**(34,447)**	(33,510)	**(107,681)**	(99,313)
Income before Minority Interests and Income Taxes	**203,313**	98,239	**510,482**	293,632
Minority interests in income of consolidated subsidiaries	**(111)**	(125)	**(368)**	(302)
Income taxes	**670**	(2,198)	**(6,703)**	(7,039)
Net Income	**$ 203,872**	$ 95,916	**$ 503,411**	$ 286,291
Limited partners' interest in net income:				
Net income	**$ 203,872**	$ 95,916	**$ 503,411**	$ 286,291
General partners' interest in net income	**(24,397)**	(14,872)	**(65,790)**	(42,203)
Limited Partners' Interest in Net Income	**$ 179,475**	$ 81,044	**$ 437,621**	$ 244,088
Limited partners' per unit net income:				
Net income per unit (Note K)	**$ 1.97**	$ 0.98	**$ 4.93**	$ 2.94
Number of Units Used in Computation *(Thousands)*	**90,920**	82,891	**88,768**	82,891

See accompanying Notes to Consolidated Financial Statements.

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ONEOK Partners, L.P. and Subsidiaries
CONSOLIDATED BALANCE SHEETS

(Unaudited)	September 30, 2008	December 31, 2007
Assets	*(Thousands of dollars)*	
Current Assets		
Cash and cash equivalents	**$ 15,803**	$ 3,213
Accounts receivable, net	**475,105**	577,989
Affiliate receivables	**43,234**	52,479
Gas and natural gas liquids in storage	**265,824**	251,219
Commodity exchanges and imbalances	**79,345**	82,037
Other current assets	**49,691**	19,961
Total Current Assets	**929,002**	986,898
Property, Plant and Equipment		
Property, plant and equipment	**5,444,041**	4,436,371
Accumulated depreciation and amortization	**849,699**	776,185
Net Property, Plant and Equipment (Note A)	**4,594,342**	3,660,186
Investments and Other Assets		
Investment in unconsolidated affiliates (Note J)	**756,449**	756,260
Goodwill and intangible assets	**678,453**	682,084
Other assets	**34,049**	26,637
Total Investments and Other Assets	**1,468,951**	1,464,981
Total Assets	**$ 6,992,295**	$ 6,112,065
Liabilities and Partners' Equity		
Current Liabilities		
Current maturities of long-term debt	**$ 11,931**	$ 11,930
Notes payable	**280,000**	100,000
Accounts payable	**759,785**	742,903
Affiliate payables	**29,699**	18,298
Commodity exchanges and imbalances	**245,882**	252,095
Other current liabilities	**151,058**	136,664
Total Current Liabilities	**1,478,355**	1,261,890
Long-term Debt, excluding current maturities	**2,593,481**	2,605,396
Deferred Credits and Other Liabilities	**43,744**	43,799
Commitments and Contingencies (Note H)		
Minority Interests in Consolidated Subsidiaries	**5,947**	5,802
Partners' Equity		
General partner	**77,520**	58,415
Common units: 54,426,087 units and 46,397,214 units issued and outstanding at September 30, 2008, and December 31, 2007, respectively	**1,360,311**	814,266
Class B units: 36,494,126 units issued and outstanding at September 30, 2008, and December 31, 2007	**1,406,515**	1,340,638
Accumulated other comprehensive income (loss) (Note E)	**26,422**	(18,141)
Total Partners' Equity	**2,870,768**	2,195,178
Total Liabilities and Partners' Equity	**$ 6,992,295**	$ 6,112,065

See accompanying Notes to Consolidated Financial Statements.

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ONEOK Partners, L.P. and Subsidiaries
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Nine Months Ended September 30,	
(Unaudited)	**2008**	**2007**
Operating Activities	*(Thousands of dollars)*	
Net income	**$ 503,411**	$ 286,291
Depreciation and amortization	**90,383**	84,326
Allowance for equity funds used during construction	**(35,788)**	(6,686)
Gain on sale of assets	**(50)**	(1,935)
Minority interests in income of consolidated subsidiaries	**368**	302
Equity earnings from investments	**(74,805)**	(64,975)
Distributions received from unconsolidated affiliates	**67,812**	77,144
Changes in assets and liabilities (net of acquisition and disposition effects):		
Accounts receivable	**98,214**	(83,065)
Affiliate receivables	**9,245**	45,650
Gas and natural gas liquids in storage	**(59,690)**	(29,357)
Accounts payable	**(52,516)**	146,880
Affiliate payables	**11,401**	1,734
Commodity exchanges and imbalances, net	**(3,521)**	22,627
Accrued interest	**32,117**	23,086
Other assets and liabilities	**(17,916)**	24,461
Cash Provided by Operating Activities	**568,665**	526,483
Investing Activities		
Changes in investments in unconsolidated affiliates	**3,063**	(5,546)
Capital expenditures (less allowance for equity funds used during construction)	**(860,167)**	(408,353)
Proceeds from sale of assets	**133**	3,959
Other	**2,450**	—
Cash Used in Investing Activities	**(854,521)**	(409,940)
Financing Activities		
Cash distributions to:		
General and limited partners	**(332,090)**	(285,998)
Minority interests	**(223)**	(147)
Borrowing (payment) of notes payable, net	**180,000**	359,000
Issuance of common units, net of discounts	**450,198**	—
Contributions from general partner	**9,508**	—
Issuance of long-term debt	**—**	598,146
Payment of long-term debt	**(8,947)**	(8,948)
Other	**—**	(5,280)
Cash Provided by Financing Activities	**298,446**	656,773
Change in Cash and Cash Equivalents	**12,590**	773,316
Cash and Cash Equivalents at Beginning of Period	**3,213**	21,102
Cash and Cash Equivalents at End of Period	**$ 15,803**	$ 794,418

See accompanying Notes to Consolidated Financial Statements.

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ONEOK Partners, L.P. and Subsidiaries
CONSOLIDATED STATEMENT OF CHANGES IN PARTNERS' EQUITY AND COMPREHENSIVE INCOME

(Unaudited)	Common Units	Class B Units	General Partner	Common Units
	(Units)		*(Thousands of dollars)*	
December 31, 2007	46,397,214	36,494,126	$ 58,415	$ 814,266
Net income	-	-	**65,790**	**257,699**
Other comprehensive income (loss) (Note E)	-	-	-	-
Total comprehensive income				
Issuance of common units (Note F)	**8,028,873**	-	-	**450,198**
Contribution from general partner (Note F)	-	-	**9,508**	-
Distributions paid (Note K)	-	-	**(56,193)**	**(161,852)**
September 30, 2008	**54,426,087**	**36,494,126**	**$ 77,520**	**$ 1,360,311**

See accompanying Notes to Consolidated Financial Statements.

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ONEOK Partners, L.P. and Subsidiaries
CONSOLIDATED STATEMENT OF CHANGES IN PARTNERS' EQUITY AND COMPREHENSIVE INCOME
(Continued)

	Class B Units	Accumulated Other Comprehensive Income (Loss)	Total Partners' Equity
		(Thousands of dollars)	
December 31, 2007	$ 1,340,638	$ (18,141)	$ 2,195,178
Net income	**179,922**	-	**503,411**
Other comprehensive income (loss) (Note E)	-	**44,563**	**44,563**
Total comprehensive income			**547,974**
Issuance of common units (Note F)	-	-	**450,198**
Contribution from general partner (Note F)	-	-	**9,508**
Distributions paid (Note K)	**(114,045)**	-	**(332,090)**
September 30, 2008	**$ 1,406,515**	**$ 26,422**	**$ 2,870,768**

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ONEOK Partners, L.P. and Subsidiaries
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

A. SUMMARY OF ACCOUNTING POLICIES

Our accompanying unaudited consolidated financial statements have been prepared in accordance with GAAP and reflect all adjustments that, in our opinion, are necessary for a fair presentation of the results for the interim periods presented. All such adjustments are of a normal recurring nature. These unaudited consolidated financial statements should be read in conjunction with our audited consolidated financial statements in our Annual Report on Form 10-K for the year ended December 31, 2007.

Our accounting policies are consistent with those disclosed in Note A of the Notes to Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2007.

Critical Accounting Policies

Impairment of Goodwill and Intangible Assets - We apply the provisions of Statement 142, "Goodwill and Other Intangible Assets," and perform our annual impairment test on July 1. There were no impairment charges resulting from our July 1, 2008, impairment testing, and no events indicating an impairment have occurred subsequent to that date.

Significant Accounting Policies

Property, Plant and Equipment - The following table sets forth our property, plant and equipment, by segment, for the periods presented.

	September 30, 2008	December 31, 2007
	(Thousands of dollars)	
Non-Regulated		
Natural Gas Gathering and Processing	**$ 1,328,693**	$ 1,227,475
Natural Gas Pipelines	**166,889**	162,390
Natural Gas Liquids Gathering and Fractionation	**851,476**	672,047
Other	**50,401**	50,482
Regulated		
Natural Gas Pipelines	**1,361,142**	1,184,112
Natural Gas Liquids Pipelines	**1,685,440**	1,139,865
Property, plant and equipment	**5,444,041**	4,436,371
Accumulated depreciation and amortization	**849,699**	776,185
Net property, plant and equipment	**$ 4,594,342**	$ 3,660,186

At September 30, 2008, and December 31, 2007, property, plant and equipment on our Consolidated Balance Sheets included construction work in process of $1.4 billion and $0.9 billion, respectively, that had not yet been put in service and therefore was not being depreciated.

Other

Fair Value Measurements - In September 2006, the FASB issued Statement 157, "Fair Value Measurements," which establishes a framework for measuring fair value and requires additional disclosures about fair value measurements. Beginning January 1, 2008, we partially applied Statement 157 as allowed by FASB Staff Position (FSP) 157-2, "Effective Date of FASB Statement No. 157," which delayed the effective date of Statement 157 for nonrecurring fair value measurements associated with our nonfinancial assets and liabilities. As of January 1, 2008, we applied the provisions of Statement 157 to our recurring fair value measurements, and the impact was not material. See Note C for disclosures of fair value measurements for our financial instruments. Under FSP 157-2, we will be required to apply Statement 157 to our nonrecurring fair value measurements associated with our nonfinancial assets and liabilities beginning January 1, 2009. We are currently reviewing the impact of Statement 157 to our nonrecurring fair value measurements associated with our nonfinancial assets and liabilities, as well as the potential impact on our consolidated financial statements. FSP 157-3, "Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active," which clarified the

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application of Statement 157 in inactive markets, was issued in October 2008 and was effective for our September 30, 2008, consolidated financial statements. FSP 157-3 did not have a material impact on our consolidated financial statements.

In February 2007, the FASB issued Statement 159, "The Fair Value Option for Financial Assets and Financial Liabilities," which allows companies to elect to measure specified financial assets and liabilities, firm commitments, and nonfinancial warranty and insurance contracts at fair value on a contract-by-contract basis, with changes in fair value recognized in earnings each reporting period. At January 1, 2008, we did not elect the fair value option under Statement 159, and therefore there was no impact on our consolidated financial statements.

Master Netting Arrangements - In April 2007, the FASB issued Staff Position No. FIN 39-1, "Amendment of FASB Interpretation No. 39," which requires entities that offset the fair value amounts recognized for derivative receivables and payables to also offset the fair value amounts recognized for the right to reclaim cash collateral with the same counterparty under a master netting agreement. We applied the provisions of FIN 39-1 to our consolidated financial statements beginning January 1, 2008, and the impact was not material. At September 30, 2008, we had no cash collateral held or posted under our master netting arrangement.

Business Combinations - In December 2007, the FASB issued Statement 141R, "Business Combinations," which will require most identifiable assets, liabilities, noncontrolling interest (previously referred to as minority interest) and goodwill acquired in a business combination to be recorded at fair value. Statement 141R is effective for our year beginning January 1, 2009, and will be applied prospectively. Because the provisions of Statement 141R are applied prospectively, our 2009 and subsequent consolidated financial statements will not be impacted unless we complete a business combination.

Noncontrolling Interests - In December 2007, the FASB issued Statement 160, "Noncontrolling Interests in Consolidated Financial Statements - an amendment of ARB No. 51," which requires noncontrolling interest (previously referred to as minority interest) to be reported as a component of equity. Statement 160 is effective for our year beginning January 1, 2009, and will require retroactive adoption of the presentation and disclosure requirements for existing minority interests. Based upon our initial review of Statement 160, we do not expect the provisions of Statement 160 to have a material impact on our consolidated financial statements; however, certain financial statement presentation changes and additional required disclosures will be applicable to us.

Derivative Instruments and Hedging Activities Disclosure - In March 2008, the FASB issued Statement 161, "Disclosures about Derivative Instruments and Hedging Activities - an amendment to FASB Statement No. 133," which requires enhanced disclosures about how derivative and hedging activities affect our financial position, financial performance and cash flows. Statement 161 is effective for our year beginning January 1, 2009, and will be applied prospectively.

Net Income Per Unit - The FASB ratified EITF 07-4, "Application of the Two-Class Method under FASB Statement No. 128 to Master Limited Partnerships," in March 2008. EITF 07-4 results in the allocation of undistributed current-period earnings to the unitholders using the two-class method in periods in which earnings exceed distributions. When distributions to participating securities exceed current-period earnings, the excess distributions generate an undistributed loss that would be allocated back to the equity interests based on the contractual terms of the partnership agreement. EITF 07-4 is effective for our year beginning January 1, 2009, and requires retrospective application. We are currently reviewing the impact of EITF 07-4 to our net income per unit computations.

Reclassifications - Certain amounts in our consolidated financial statements have been reclassified to conform to the 2008 presentation. These reclassifications did not impact previously reported net income or partners' equity.

B. ACQUISITION

In October 2007, we completed the acquisition of an interstate natural gas liquids and refined petroleum products pipeline system and related assets from a subsidiary of Kinder Morgan Energy Partners, L.P. for approximately $300 million, before working capital adjustments. The system extends from Bushton and Conway, Kansas, to Chicago, Illinois, and transports, stores and delivers a full range of NGL and refined petroleum products. The FERC-regulated system spans 1,624 miles and has a capacity to transport up to 134 MBbl/d. The transaction also included approximately 978 MBbl of owned storage capacity, eight NGL terminals and a 50 percent ownership of Heartland. ConocoPhillips owns the other 50 percent of Heartland and is the managing partner of the Heartland joint venture, which consists primarily of three refined petroleum products terminals and connecting pipelines. Our investment in Heartland is accounted for under the equity method of accounting. Financing for this transaction came from a portion of the proceeds of our September 2007 issuance of $600 million 6.85 percent Senior Notes due 2037. The working capital settlement was finalized in April 2008, with no material adjustments.

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C. FAIR VALUE MEASUREMENTS

As discussed in Note A, we applied the provisions of Statement 157 as of January 1, 2008, to our recurring fair value measurements.

Determining Fair Value - Statement 157 defines fair value as the price that would be received to sell an asset or transfer a liability in an orderly transaction between market participants at the measurement date. We use the income approach to determine the fair value of our derivative assets and liabilities and consider the markets in which the transactions are executed. While many of the contracts in our portfolio are executed in liquid markets where price transparency exists, some contracts are executed in markets for which market prices may exist but the market may be relatively inactive. This results in limited price transparency that requires management's judgment and assumptions to estimate fair values. For certain transactions, we utilize modeling techniques using NYMEX-settled pricing data and historical correlations of NGL product prices to crude oil. We validate our valuation inputs with third-party information and settlement prices from other sources, where available. In addition, as prescribed by the income approach, we compute the fair value of our derivative portfolio by discounting the projected future cash flows from our derivative assets and liabilities to present value. The interest rate yields used to calculate the present value discount factors are derived from LIBOR, Eurodollar futures and Treasury swaps. The projected cash flows are then multiplied by the appropriate discount factors to determine the present value or fair value of our derivative instruments. Finally, we consider the credit risk of our counterparties with whom our derivative assets and liabilities are executed. Although we use our best estimates to determine the fair value of the derivative contracts we have executed, the ultimate market prices realized could differ from our estimates, and the differences could be significant.

Fair Value Hierarchy - Statement 157 establishes the fair value hierarchy that prioritizes inputs to valuation techniques based on observable and unobservable data and categorizes the inputs into three levels, with the highest priority given to Level 1 and the lowest priority given to Level 3. The levels are described below.

- Level 1 - Unadjusted quoted prices in active markets for identical assets or liabilities.
- Level 2 - Significant observable pricing inputs other than quoted prices included within Level 1 that are either directly or indirectly observable as of the reporting date. Essentially, this represents inputs that are derived principally from or corroborated by observable market data.
- Level 3 - Generally unobservable inputs, which are developed based on the best information available and may include our own internal data.

Determining the appropriate classification of our fair value measurements within the fair value hierarchy requires management's judgment regarding the degree to which market data is observable or corroborated by observable market data. During the third quarter of 2008, we revised our categorization of fair value measurements for non-exchange traded derivative contracts from Level 1 to Level 2, as discussed below.

The following table sets forth our recurring fair value measurements for the period indicated.

	September 30, 2008			
	Level 1	**Level 2**	**Level 3**	**Total**
	(Thousands of dollars)			
Derivatives				
Assets	**$ —**	**$10,648**	**$15,065**	**$25,713**

For derivatives for which fair value is determined based on multiple inputs, Statement 157 requires that the measurement for an individual derivative be categorized within a single level, based on the lowest level input that is significant to the fair value measurement in its entirety.

When our fair value measurements that are based on NYMEX-settled prices are associated with exchange-traded instruments, we classify those derivatives as Level 1. These measurements may include futures for natural gas and crude oil which are valued based on unadjusted quoted prices in active markets. Our Level 2 fair value measurements are based on NYMEX-settled prices which are utilized to determine the fair value of certain non-exchange traded financial instruments, including natural gas and crude oil swaps. For our Level 3 inputs, we utilize modeling techniques using NYMEX-settled pricing data and historical correlations of NGL product prices to crude oil.

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The following tables set forth a reconciliation of our Level 3 fair value measurements for the periods indicated.

	Derivative Assets (Liabilities)
	(Thousands of dollars)
Net liabilities at June 30, 2008	$ (37,704)
Total realized/unrealized gains (losses):	
Included in earnings (a)	**(3,407)**
Included in other comprehensive income (loss)	**56,176**
Transfers in and/or out of Level 3	**-**
Net assets at September 30, 2008	**$ 15,065**
Total gains (losses) for the three-month period included in earnings attributable to the change in unrealized gain (loss) relating to assets and liabilities still held as of September 30, 2008 (a)	**$ (3,422)**

(a) - Reported in revenues in our Consolidated Statements of Income.

	Derivative Assets (Liabilities)
	(Thousands of dollars)
Net liabilities at January 1, 2008	$ (16,400)
Total realized/unrealized gains (losses):	
Included in earnings (a)	**(2,434)**
Included in other comprehensive income (loss)	**33,899**
Transfers in and/or out of Level 3	**-**
Net assets at September 30, 2008	**$ 15,065**
Total gains (losses) for the nine-month period included in earnings attributable to the change in unrealized gain (loss) relating to assets and liabilities still held as of September 30, 2008 (a)	**$ (3,422)**

(a) - Reported in revenues in our Consolidated Statements of Income.

D. DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

We utilize financial instruments to reduce our market risk exposure to interest rate and commodity price fluctuations and to achieve more predictable cash flows. We follow established policies and procedures to assess risk and approve, monitor and report our financial instrument activities. We do not use these instruments for trading purposes.

Cash Flow Hedges - Our Natural Gas Gathering and Processing segment primarily utilizes NYMEX-based futures, collars and over-the-counter swaps, which are designated as cash flow hedges, to hedge our exposure to volatility in the price of natural gas, NGLs and condensate. At September 30, 2008, our Consolidated Balance Sheet reflected an unrealized gain of $29.3 million in accumulated other comprehensive income (loss), with a corresponding offset in derivative financial instrument assets and liabilities, all of which will be recognized over the next 15 months. If prices remain at current levels, we will recognize $22.5 million in gains over the next 12 months, and we will recognize gains of $6.8 million thereafter. Net gains and losses related to the ineffective portion of our hedges are reclassified out of accumulated other comprehensive income (loss) to revenues in the period the ineffectiveness occurs. Ineffectiveness related to our cash flow hedges was not material for the three and nine months ended September 30, 2008 and 2007. In the event that it becomes probable that a forecasted transaction will not occur, we would discontinue cash flow hedge treatment, which would affect earnings. There were no gains or losses during the three and nine months ended September 30, 2008 and 2007, due to the discontinuance of cash flow hedge treatment.

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Fair Value Hedges - In prior years, we terminated various interest-rate swap agreements. The net savings from the termination of these swaps is being recognized in interest expense over the terms of the debt instruments originally hedged. Interest expense savings for the nine months ended September 30, 2008, from amortization of terminated swaps was $2.8 million, and the remaining amortization of terminated swaps will be recognized over the following periods.

	(Millions of dollars)
Remainder of 2008	$ 0.9
2009	3.7
2010	3.7
2011	0.9

At September 30, 2008, none of the interest on our fixed-rate debt was swapped to floating using interest rate swaps.

E. OTHER COMPREHENSIVE INCOME (LOSS)

The table below shows other comprehensive income (loss) for the periods indicated.

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
	2008	**2007**	**2008**	**2007**
	(Thousands of dollars)			
Unrealized gains (losses) on derivatives	**$ 66,661**	$ (1,361)	**$ 13,496**	$ (8,089)
Less: Realized losses recognized in net income	**(14,202)**	-	**(31,067)**	-
Other comprehensive income (loss)	**$ 80,863**	$ (1,361)	**$ 44,563**	$ (8,089)

The table below shows the balance in accumulated other comprehensive income (loss) for the period indicated.

	Unrealized Gains (Losses) on Derivatives
	(Thousands of dollars)
December 31, 2007	$ (18,141)
Other comprehensive income (loss)	**44,563**
September 30, 2008	**$ 26,422**

F. PARTNERS' EQUITY

ONEOK and its affiliates own all of the Class B units, 5,900,000 common units and the entire 2 percent general partner interest in us, which together constituted a 47.7 percent equity interest in us at September 30, 2008.

In March 2008, we completed a public offering of 2.5 million common units at $58.10 per common unit, generating net proceeds of approximately $140.4 million after deducting underwriting discounts but before offering expenses. In addition, we sold 5.4 million common units to ONEOK in a private placement, generating proceeds of approximately $303.2 million. In conjunction with the public offering of common units and the private placement, ONEOK Partners GP contributed $9.4 million in order to maintain its 2 percent general partner interest in us.

In April 2008, we sold an additional 128,873 common units at $58.10 per common unit to the underwriters of the public offering upon the partial exercise of their option to purchase additional common units to cover over-allotments. We received net proceeds of approximately $7.2 million from the sale of the common units after deducting underwriting discounts but before offering expenses. In conjunction with the partial exercise by the underwriters, ONEOK Partners GP contributed $0.2 million in order to maintain its 2 percent general partner interest in us.

We used a portion of the proceeds from the sale of common units and the general partner contributions to repay borrowings under our revolving credit agreement (Partnership Credit Agreement).

The following summarizes our quarterly cash distribution activity for 2008.

- In January 2008, we declared a cash distribution of $1.025 per unit for the fourth quarter of 2007. The distribution was paid on February 14, 2008, to unitholders of record on January 31, 2008.

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- In April 2008, we declared a cash distribution of $1.04 per unit for the first quarter of 2008. The distribution was paid on May 15, 2008, to unitholders of record as of April 30, 2008.
- In July 2008, we declared a cash distribution of $1.06 per unit for the second quarter of 2008. The distribution was paid on August 14, 2008, to unitholders of record as of July 31, 2008.
- In October 2008, we declared a cash distribution of $1.08 per unit ($4.32 per unit on an annualized basis) for the third quarter of 2008. The distribution will be paid on November 14, 2008, to unitholders of record as of October 31, 2008.

Our general partner's percentage interest in quarterly distributions increases after certain specified target levels are met. For additional information, see "Cash Distribution Policy" under Part II, Item 5, Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities, in our Annual Report on Form 10-K for the year ended December 31, 2007.

G. CREDIT FACILITIES

Our Partnership Credit Agreement contains typical covenants as discussed in Note F of the Notes to Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2007. At September 30, 2008, we were in compliance with all covenants.

At September 30, 2008, we had $280 million in borrowings outstanding and $720 million of credit available under the Partnership Credit Agreement.

In October 2008, we borrowed $590 million under our Partnership Credit Agreement. With this borrowing, we had $870 million outstanding and $130 million available under our Partnership Credit Agreement at October 31, 2008.

We have a $15 million Senior Unsecured Letter of Credit Facility and Reimbursement Agreement with Wells Fargo Bank, N.A., of which $12 million is currently being used, and an agreement with Royal Bank of Canada, pursuant to which a $12 million letter of credit was issued. Both agreements are used to support various permits required by the KDHE for our ongoing business in Kansas.

H. COMMITMENTS AND CONTINGENCIES

As a result of an internal review of a transaction that was brought to the attention of one of our affiliates by a third party, we conducted an internal review of transactions that may have violated FERC natural gas capacity release rules or related rules and determined that there were transactions that should have been disclosed to the FERC. We notified the FERC of this review and filed a report with the FERC regarding these transactions in March 2008. We are cooperating fully with the FERC and have taken steps to ensure that current and future transactions comply with applicable FERC regulations. We are unable to predict the outcome of any FERC action in this matter. At this time, we do not believe that penalties associated with potential violations will have a material impact on our results of operations, financial position or liquidity.

I. SEGMENTS

Segment Descriptions - Our operations are divided into strategic business segments based on similarities in economic characteristics, products and services, types of customers, methods of distribution and regulatory environment, as follows:

- our Natural Gas Gathering and Processing segment primarily gathers and processes unprocessed natural gas;
- our Natural Gas Pipelines segment primarily operates regulated interstate and intrastate natural gas transmission pipelines and natural gas storage facilities;
- our Natural Gas Liquids Gathering and Fractionation segment primarily gathers, treats and fractionates NGLs and stores and markets NGL products; and
- our Natural Gas Liquids Pipelines segment primarily operates FERC-regulated interstate natural gas liquids gathering and distribution pipelines.

Accounting Policies - The accounting policies of the segments are the same as those described in Note A and Note J of the Notes to Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2007. Intersegment and affiliate sales are recorded on the same basis as sales to unaffiliated customers. Our Natural Gas Gathering and Processing segment sells natural gas to ONEOK and its subsidiaries. A portion of our Natural Gas Pipelines segment's revenues are from subsidiaries of ONEOK that utilize transportation and storage services. Corporate overhead costs relating to a reportable segment have been allocated for the purpose of calculating operating income.

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Customers - For the three months ended September 30, 2008 and 2007, we had no single external customer from which we received 10 percent or more of our consolidated revenues. We had one customer, Dow Hydrocarbons and Resources L.L.C., from which we received $686.3 million, or approximately 11 percent of our consolidated revenues, for the nine months ended September 30, 2008. All of these revenues were received by our Natural Gas Liquids Gathering and Fractionation segment. For the nine months ended September 30, 2007, we had no single external customer from which we received 10 percent or more of our consolidated revenues.

Operating Segment Information - The following tables set forth certain selected financial information for our operating segments for the periods indicated. Amounts in prior periods have been restated to conform to our current presentation.

Three Months Ended September 30, 2008	**Natural Gas Gathering and Processing**	**Natural Gas Pipelines (a)**	**Natural Gas Liquids Gathering and Fractionation**	**Natural Gas Liquids Pipelines (b)**	**Other and Eliminations**	**Total**
			(Thousands of dollars)			
Sales to unaffiliated customers	**$ 129,305**	**$ 55,528**	**$ 1,836,627**	**$ 10,838**	**$ 47**	**$2,032,345**
Sales to affiliated customers	**178,167**	**30,595**	**—**	**—**	**—**	**208,762**
Intersegment sales	**190,403**	**567**	**6,695**	**23,708**	**(221,373)**	**—**
Total revenues	**$ 497,875**	**$ 86,690**	**$ 1,843,322**	**$ 34,546**	**$ (221,326)**	**$2,241,107**
Net margin	**$ 111,720**	**$ 65,762**	**$ 118,630**	**$ 29,754**	**$ (466)**	**$ 325,400**
Operating costs	**35,651**	**23,852**	**22,954**	**14,986**	**45**	**97,488**
Depreciation and amortization	**12,533**	**8,607**	**5,901**	**3,361**	**6**	**30,408**
Gain (loss) on sale of assets	**2**	**—**	**13**	**7**	**—**	**22**
Operating income	**$ 63,538**	**$ 33,303**	**$ 89,788**	**$ 11,414**	**$ (517)**	**$ 197,526**
Equity earnings from investments	**$ 8,819**	**$ 20,207**	**$ —**	**$ 386**	**$ —**	**$ 29,412**
Capital expenditures	**$ 35,769**	**$ 107,822**	**$ 52,558**	**$ 139,431**	**$ —**	**$ 335,580**

(a) - Our Natural Gas Pipelines segment has regulated and non-regulated operations. Our Natural Gas Pipelines segment's regulated operations had revenues of $71.2 million, net margin of $52.8 million and operating income of $25.9 million for the three months ended September 30, 2008.

(b) - All of our Natural Gas Liquids Pipelines segment's operations are regulated.

Three Months Ended September 30, 2007	**Natural Gas Gathering and Processing**	**Natural Gas Pipelines (a)**	**Natural Gas Liquids Gathering and Fractionation**	**Natural Gas Liquids Pipelines (b)**	**Other and Eliminations**	**Total**
			(Thousands of dollars)			
Sales to unaffiliated customers	$ 81,660	$ 44,550	$ 1,113,467	$ —	$ 4	$1,239,681
Sales to affiliated customers	141,907	28,669	—	—	—	170,576
Intersegment sales	125,384	145	6,630	19,672	(151,831)	—
Total revenues	$ 348,951	$ 73,364	$ 1,120,097	$ 19,672	$ (151,827)	$1,410,257
Net margin	$ 87,625	$ 60,247	$ 48,827	$ 17,981	$ (796)	$ 213,884
Operating costs	31,808	24,109	17,787	5,648	727	80,079
Depreciation and amortization	11,277	8,089	6,439	2,987	8	28,800
Gain (loss) on sale of assets	10	73	27	1	—	111
Operating income	$ 44,550	$ 28,122	$ 24,628	$ 9,347	$ (1,531)	$ 105,116
Equity earnings from investments	$ 6,180	$ 16,493	$ —	$ (511)	$ —	$ 22,162
Capital expenditures	$ 32,307	$ 44,561	$ 20,645	$ 104,428	$ 21	$ 201,962

(a) - Our Natural Gas Pipelines segment has regulated and non-regulated operations. Our Natural Gas Pipelines segment's regulated operations had revenues of $61.2 million, net margin of $48.1 million and operating income of $20.6 million for the three months ended September 30, 2007.

(b) - All of our Natural Gas Liquids Pipelines segment's operations are regulated.

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Nine Months Ended September 30, 2008	Natural Gas Gathering and Processing	Natural Gas Pipelines (a)	Natural Gas Liquids Gathering and Fractionation	Natural Gas Liquids Pipelines (b)	Other and Eliminations	Total
			(Thousands of dollars)			
Sales to unaffiliated customers	**$ 366,095**	**$ 173,442**	**$ 5,267,185**	**$ 40,845**	**$ 48**	**$5,847,615**
Sales to affiliated customers	**504,541**	**91,878**	**—**	**—**	**—**	**596,419**
Intersegment sales	**602,542**	**1,338**	**21,761**	**67,160**	**(692,801)**	**—**
Total revenues	**$ 1,473,178**	**$ 266,658**	**$ 5,288,946**	**$ 108,005**	**$ (692,753)**	**$6,444,034**
Net margin	**$ 336,746**	**$ 196,173**	**$ 255,494**	**$ 88,480**	**$ (2,035)**	**$ 874,858**
Operating costs	**101,538**	**67,900**	**61,575**	**42,171**	**(456)**	**272,728**
Depreciation and amortization	**36,431**	**25,547**	**17,188**	**11,200**	**17**	**90,383**
Gain (loss) on sale of assets	**(3)**	**(18)**	**31**	**8**	**32**	**50**
Operating income	**$ 198,774**	**$ 102,708**	**$ 176,762**	**$ 35,117**	**$ (1,564)**	**$ 511,797**
Equity earnings from investments	**$ 23,989**	**$ 49,421**	**$ —**	**$ 1,395**	**$ —**	**$ 74,805**
Investment in unconsolidated affiliates	**$ 323,537**	**$ 403,373**	**$ —**	**$ 29,539**	**$ —**	**$ 756,449**
Minority interests in consolidated subsidiaries	**$ —**	**$ 5,800**	**$ —**	**$ 132**	**$ 15**	**$ 5,947**
Total assets	**$ 1,593,872**	**$ 1,371,178**	**$ 1,982,549**	**$ 1,702,542**	**$ 342,154**	**$6,992,295**
Capital expenditures	**$ 98,604**	**$ 159,810**	**$ 137,177**	**$ 464,511**	**$ 65**	**$ 860,167**

(a) - Our Natural Gas Pipelines segment has regulated and non-regulated operations. Our Natural Gas Pipelines segment's regulated operations had revenues of $221.7 million, net margin of $155.0 million and operating income of $76.9 million for the nine months ended September 30, 2008.

(b) - All of our Natural Gas Liquids Pipelines segment's operations are regulated.

Nine Months Ended September 30, 2007	Natural Gas Gathering and Processing	Natural Gas Pipelines (a)	Natural Gas Liquids Gathering and Fractionation	Natural Gas Liquids Pipelines (b)	Other and Eliminations	Total
			(Thousands of dollars)			
Sales to unaffiliated customers	$ 292,867	$ 140,394	$ 3,029,248	$ —	$ 30	$3,462,539
Sales to affiliated customers	413,027	78,679	—	—	—	491,706
Intersegment sales	328,695	652	19,416	56,194	(404,957)	—
Total revenues	$ 1,034,589	$ 219,725	$ 3,048,664	$ 56,194	$ (404,927)	$3,954,245
Net margin	$ 249,396	$ 179,680	$ 155,295	$ 51,933	$ 520	$ 636,824
Operating costs	96,399	69,953	49,387	16,551	5,093	237,383
Depreciation and amortization	33,544	24,246	17,525	8,990	21	84,326
Gain (loss) on sale of assets	1,823	79	31	2	—	1,935
Operating income	$ 121,276	$ 85,560	$ 88,414	$ 26,394	$ (4,594)	$ 317,050
Equity earnings from investments	$ 19,518	$ 45,275	$ —	$ 182	$ —	$ 64,975
Investment in unconsolidated affiliates	$ 297,581	$ 434,827	$ —	$ 8,902	$ —	$ 741,310
Minority interests in consolidated subsidiaries	$ —	$ 5,724	$ —	$ 22	$ 15	$ 5,761
Total assets	$ 1,442,511	$ 1,181,898	$ 1,582,772	$ 700,995	$ 1,156,744	$6,064,920
Capital expenditures	$ 72,235	$ 90,635	$ 43,234	$ 202,222	$ 27	$ 408,353

(a) - Our Natural Gas Pipelines segment has regulated and non-regulated operations. Our Natural Gas Pipelines segment's regulated operations had revenues of $182.7 million, net margin of $143.1 million and operating income of $63.1 million for the nine months ended September 30, 2007.

(b) - All of our Natural Gas Liquids Pipelines segment's operations are regulated.

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J. UNCONSOLIDATED AFFILIATES

Equity Earnings from Investments - The following table sets forth our equity earnings from investments for the periods indicated.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	**2007**	**2008**	**2007**
	(Thousands of dollars)			
Northern Border Pipeline	**$ 20,090**	$ 16,363	**$ 48,752**	$ 44,915
Bighorn Gas Gathering, L.L.C.	**2,044**	1,782	**6,367**	5,482
Fort Union Gas Gathering	**4,033**	2,224	**9,792**	7,379
Lost Creek Gathering Company, L.L.C.	**1,345**	1,694	**4,427**	3,327
Other	**1,900**	99	**5,467**	3,872
Equity earnings from investments	**$ 29,412**	$ 22,162	**$ 74,805**	$ 64,975

Unconsolidated Affiliates Financial Information - Summarized combined financial information of our unconsolidated affiliates is presented below.

	Three Months Ended September 30,		Nine Months Ended September 30,	
(Unaudited)	**2008**	**2007**	**2008**	**2007**
	(Thousands of dollars)			
Income Statement				
Revenues	**$ 98,298**	$ 102,417	**$ 304,733**	$ 291,304
Operating expenses	**44,382**	42,817	**132,927**	125,522
Net income	**64,217**	47,571	**153,965**	131,054
Distributions paid to us	**$ 30,466**	$ 20,078	**$ 91,093**	$ 77,144

K. NET INCOME PER UNIT

Net income per unit is computed by dividing net income, after deducting the general partner's allocation, by the weighted average number of outstanding limited partner units. The general partner owns the entire 2 percent interest in us and also owns incentive distribution rights that provide for an increasing proportion of cash distributions from the partnership as the distributions made to limited partners increase above specified levels. For purposes of our calculation of net income per unit, net income is generally allocated to the general partner as follows: (i) an amount based upon the 2 percent general partner interest in net income and (ii) the amount of the general partner's incentive distribution rights based on the total cash distributions declared for the period. The amount of incentive distribution allocated to our general partner totaled $20.3 million and $55.7 million for the three and nine months ended September 30, 2008, respectively. Distributions paid to our general partner and shown on our Consolidated Statement of Changes in Partners' Equity and Comprehensive Income of $56.2 million included $49.5 million in incentive distributions paid to our general partner during the first nine months of 2008. Gains resulting from interim capital transactions, as defined in our Partnership Agreement, are generally not subject to distribution; however, our Partnership Agreement provides that if such distributions were made, the incentive distribution rights would not apply. Accordingly, the gain (loss) on sale of assets for the three and nine months ended September 30, 2008 and 2007 had no impact on the incentive distribution rights.

L. RELATED-PARTY TRANSACTIONS

Intersegment and affiliate sales are recorded on the same basis as sales to unaffiliated customers. Our Natural Gas Gathering and Processing segment sells natural gas to ONEOK and its subsidiaries. A portion of our Natural Gas Pipelines segment's revenues are from ONEOK and its subsidiaries that utilize natural gas transportation and storage services.

We have certain contractual rights to the Bushton Plant that is leased by OBPI. Our Processing and Services Agreement with ONEOK and OBPI sets out the terms by which OBPI provides services at the Bushton Plant through 2012. We have contracted for all of the capacity of the Bushton Plant from OBPI. In exchange, we pay OBPI for all direct costs and expenses of the Bushton Plant, including reimbursement of a portion of OBPI's obligations under equipment leases covering the Bushton Plant.

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Under the Services Agreement with ONEOK, ONEOK Partners GP and NBP Services, our operations and the operations of ONEOK and its affiliates can combine or share certain common services in order to operate more efficiently and cost effectively. Under the Services Agreement, ONEOK provides to us at least the type and amount of services that it provides to its affiliates, including those services required to be provided pursuant to our Partnership Agreement. ONEOK Partners GP operates our interstate natural gas pipeline assets according to each pipeline's operating agreement. ONEOK Partners GP may purchase services from ONEOK and its affiliates pursuant to the terms of the Services Agreement. ONEOK Partners GP has no employees and utilizes the services of ONEOK and ONEOK Services Company to fulfill its responsibilities.

ONEOK and its affiliates provide a variety of services to us under the Services Agreement, including cash management and financial services, employee benefits provided through ONEOK's benefit plans, administrative services, insurance and office space leased in ONEOK's headquarters building and other field locations. Where costs are specifically incurred on behalf of one of our affiliates, the costs are billed directly to us by ONEOK. In other situations, the costs may be allocated to us through a variety of methods, depending upon the nature of the expense and activities. For example, a service that applies equally to all employees is allocated based upon the number of employees. However, an expense benefiting the consolidated company but having no direct basis for allocation is allocated by the modified Distrigas method, a method using a combination of ratios that include gross plant and investment, earnings before interest and taxes and payroll expense. All costs directly charged or allocated to us are included in our Consolidated Statements of Income.

An affiliate of ONEOK enters into some of the commodity derivative contracts at the direction of and on behalf of our Natural Gas Gathering and Processing segment. See Note D for a discussion of our derivative instruments and hedging activities.

The following table sets forth the transactions with related parties for the periods indicated.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	**2007**	**2008**	**2007**
	(Thousands of dollars)			
Revenues	**$ 208,762**	$ 170,576	**$ 596,419**	$ 491,706
Administrative and general expenses	**$ 53,154**	$ 36,771	**$ 143,387**	$ 121,981

In addition, concurrent with our sale of common units to the public, we sold 5.4 million common units to ONEOK in March 2008 in a private placement, generating proceeds of approximately $303.2 million. ONEOK Partners GP also made additional general partner contributions to us in March and April 2008. See Note F for additional information.

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ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis should be read in conjunction with our unaudited consolidated financial statements and the Notes to Consolidated Financial Statements in this Quarterly Report on Form 10-Q, as well as our Annual Report on Form 10-K for the year ended December 31, 2007.

EXECUTIVE SUMMARY

The following discussion highlights some of our achievements and significant issues affecting us for the periods presented. Please refer to the "Liquidity and Capital Resources," "Capital Projects," and "Financial Results and Operating Information" sections of Management's Discussion and Analysis of Financial Condition and Results of Operations and our Consolidated Financial Statements for additional information.

In March 2008, we completed a public offering of 2.5 million common units at $58.10 per common unit, generating net proceeds of approximately $140.4 million after deducting underwriting discounts but before offering expenses. In addition, we sold 5.4 million common units to ONEOK in a private placement, generating proceeds of approximately $303.2 million. In conjunction with the public offering of common units and the private placement, ONEOK Partners GP contributed $9.4 million in order to maintain its 2 percent general partner interest in us.

In April 2008, we sold an additional 128,873 common units at $58.10 per common unit to the underwriters of the public offering upon the partial exercise of their option to purchase additional common units to cover over-allotments. We received net proceeds of approximately $7.2 million from the sale of the common units after deducting underwriting discounts but before offering expenses. In conjunction with the partial exercise by the underwriters, ONEOK Partners GP contributed $0.2 million in order to maintain its 2 percent general partner interest in us. As a result of these transactions, ONEOK now holds an aggregate 47.7 percent equity interest in us.

We used a portion of the proceeds from the sale of common units and the general partner contributions to repay borrowings under our revolving credit agreement (Partnership Credit Agreement).

In October 2008, we declared an increase in our cash distribution to $1.08 per unit ($4.32 per unit on an annualized basis), an increase of approximately 7 percent over the $1.01 per unit declared in October 2007.

Partial operations began in October 2008 on the Overland Pass Pipeline. In September 2008, the Woodford Shale natural gas liquids pipeline extension was placed into service, and the final phase of the Fort Union Gas Gathering expansion project was placed into service in July 2008. In January 2008, Midwestern Gas Transmission, our subsidiary, placed its eastern extension pipeline into service.

Net income per unit increased to $1.97 for the three months ended September 30, 2008, compared with $0.98 for the same period in 2007. For the nine-month period, net income per unit increased to $4.93 from $2.94 for the same period last year. The increase in net income per unit for the three- and nine-month periods is primarily due to the following:

- wider NGL product price differentials, increased NGL gathering and fractionation volumes and certain operational measurement gains, primarily at NGL storage caverns, in our Natural Gas Liquids Gathering and Fractionation segment,
- higher realized commodity prices, higher volumes sold and processed, and improved contractual terms in our Natural Gas Gathering and Processing segment,
- increased transportation and storage margins as a result of the impact of higher natural gas prices on retained fuel and new and renegotiated storage contracts in our Natural Gas Pipelines segment, and
- incremental operating income in our Natural Gas Liquids Pipelines segment from the assets acquired from Kinder Morgan Energy Partners, LP (Kinder Morgan) in October 2007.

During September 2008, our Natural Gas Gathering and Processing segment, Natural Gas Liquids Gathering and Fractionation segment, and Natural Gas Liquids Pipelines segment experienced disruptions related to Hurricane Ike. Without these disruptions, we estimate net margin would have been approximately $7.8 million higher.

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SIGNIFICANT ACQUISITION

In October 2007, we completed the acquisition of an interstate natural gas liquids and refined petroleum products pipeline system and related assets from a subsidiary of Kinder Morgan for approximately $300 million, before working capital adjustments. The system extends from Bushton and Conway, Kansas, to Chicago, Illinois, and transports, stores and delivers a full range of NGL and refined petroleum products. The FERC-regulated system spans 1,624 miles and has a capacity to transport up to 134 MBbl/d. The transaction also included approximately 978 MBbl of owned storage capacity, eight NGL terminals and a 50 percent ownership of Heartland. ConocoPhillips owns the other 50 percent of Heartland and is the managing partner of the Heartland joint venture, which consists primarily of three refined petroleum products terminals and connecting pipelines. Our investment in Heartland is accounted for under the equity method of accounting. Financing for this transaction came from a portion of the proceeds of our September 2007 issuance of $600 million 6.85 percent Senior Notes due 2037. The working capital settlement was finalized in April 2008, with no material adjustments. These assets are included in our Natural Gas Liquids Pipelines segment.

CAPITAL PROJECTS

Woodford Shale Natural Gas Liquids Pipeline Extension - The 78-mile natural gas liquids gathering pipeline connecting two natural gas processing plants, operated by Devon Energy Corporation and Antero Resources Corporation, was placed into service in September 2008. The final project cost is estimated to be $36 million, excluding AFUDC. These two plants are expected to have the capacity to produce approximately 25 MBbl/d of unfractionated NGLs. The natural gas liquids production is gathered by our existing Mid-Continent natural gas liquids gathering pipelines. Upon completion of the Arbuckle Pipeline project, the Woodford Shale natural gas liquids production is expected to be transported through the Arbuckle Pipeline to our Mont Belvieu, Texas, fractionation facility. This project is in our Natural Gas Liquids Gathering and Fractionation segment.

Overland Pass Pipeline Company - In May 2006, we entered into an agreement with a subsidiary of The Williams Companies, Inc. (Williams) to form a joint venture called Overland Pass Pipeline Company. Overland Pass Pipeline Company is building a 760-mile natural gas liquids pipeline from Opal, Wyoming, to the Mid-Continent natural gas liquids market center in Conway, Kansas. The Overland Pass Pipeline is designed to transport approximately 110 MBbl/d of unfractionated NGLs and can be increased to approximately 255 MBbl/d with additional pump facilities. During 2006, we paid $11.6 million to Williams for the acquisition of our interest in the joint venture and for reimbursement of initial capital expenditures. As the 99 percent owner of the joint venture, we are managing the construction project, advancing all costs associated with construction and operating the pipeline. Within two years of the pipeline becoming fully operational, Williams will have the option to increase its ownership up to 50 percent by reimbursing us for certain costs in accordance with the joint venture’s operating agreement. If Williams exercises its option to increase its ownership to the full 50 percent, Williams would have the option to become operator. Partial operations began in October 2008, with Williams’ Echo Springs plant beginning to deliver 30 MBbl/d of unfractionated NGLs into the pipeline. The remaining portion of the pipeline from Opal, Wyoming, to Echo Springs, Wyoming, is substantially complete and scheduled for startup in the fourth quarter of 2008.

As part of a long-term agreement, Williams dedicated its NGL production of approximately 60 MBbl/d from two of its natural gas processing plants in Wyoming to the Overland Pass Pipeline. We will provide downstream fractionation, storage and transportation services to Williams. We have also reached agreements with certain producers for supply commitments of up to an additional 80 MBbl/d, and we are negotiating agreements with other producers for supply commitments that could add an additional 60 MBbl/d of supply to this pipeline within the next three to five years. The pipeline project is currently estimated to cost in the range of $575 million to $590 million, excluding AFUDC, which remains unchanged from the previous quarter. Since our initial estimate of $433 million in early 2006, there has been a significant increase in the demand for pipeline construction-related services, which has led to higher construction labor and equipment rates. Additionally, compliance with federal restrictions on construction in wildlife sensitive areas increased costs and resulted in construction delays that further impacted costs due to winter construction.

We are also investing in the range of $230 million to $240 million, excluding AFUDC, which remains unchanged from the previous quarter, to expand our existing fractionation and storage capabilities and the capacity of our natural gas liquids distribution pipelines. Since our initial estimate of $216 million, these expansion projects have experienced cost increases related to further design enhancements adding 30 MBbl/d of fractionation capacity, increased construction labor rates, increased material costs and increased costs resulting from heavy spring rainfall. Part of this expansion will increase the fractionation capacity from 80 MBbl/d to 150 MBbl/d. Phase I of the fractionator upgrade was completed in August 2008, placed in service and is capable of fractionating up to 80 MBbl/d. Phase II is expected to begin operation in the fourth quarter of 2008. Additionally, portions of our natural gas liquids distribution pipeline upgrades were completed in the second

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and third quarters of 2008. Overland Pass Pipeline Company is included in our Natural Gas Liquids Pipelines segment, while the associated expansions are included in our Natural Gas Liquids Gathering and Fractionation segment and our Natural Gas Liquids Pipelines segment.

Piceance Lateral Pipeline - In March 2007, we announced that Overland Pass Pipeline Company also plans to construct a 150-mile lateral pipeline with capacity to transport as much as 100 MBbl/d of unfractionated NGLs from the Piceance Basin in Colorado to the Overland Pass Pipeline. Williams announced that it intends to construct a new natural gas processing plant in the Piceance Basin and will dedicate its NGL production from that plant and an existing plant to be transported by the lateral pipeline, totaling approximately 30 MBbl/d. We continue to negotiate with other producers for supply commitments. In October 2008, this project received the approval of various state and federal regulatory authorities allowing construction to commence. Construction began during the fourth quarter of 2008 and is expected to be completed during the third quarter of 2009. The completion date has been revised from the second quarter of 2009 to the third quarter of 2009 due to a delay in the approval of our construction permit from the federal Bureau of Land Management. The project is currently estimated to cost in the range of $110 million to $140 million, excluding AFUDC, which remains unchanged from the previous quarter. This project is in our Natural Gas Liquids Pipelines segment.

D-J Basin Lateral Pipeline - In September 2008, we announced plans to construct a 125-mile natural gas liquids lateral pipeline from the Denver-Julesburg Basin in northeastern Colorado to the Overland Pass Pipeline with capacity to transport as much as 55 MBbl/d of unfractionated NGLs. The project is currently estimated to cost in the range of $70 million to $80 million, excluding AFUDC. We have supply commitments for up to 33 MBbl/d of unfractionated NGLs with potential for an additional 10 MBbl/d of supply from new drilling and plant upgrades in the next two years. The pipeline is currently under construction and projected to be partially in service during the fourth quarter of 2008 and fully completed during the first quarter of 2009. This project is in our Natural Gas Liquids Pipelines segment.

Arbuckle Natural Gas Liquids Pipeline - In March 2007, we announced plans to build the 440-mile Arbuckle Pipeline, a natural gas liquids pipeline from southern Oklahoma through northern Texas and continuing on to the Texas Gulf Coast. Current estimated costs are in the range of $340 million to $360 million, excluding AFUDC, which remains unchanged from the previous quarter. Negotiations with pipeline contractors have recently been completed, and the resulting construction labor rates have increased our project costs from our original estimate of $260 million. We have also experienced higher than originally expected acquisition costs for pipeline easements, particularly in the Barnett Shale area, along with increased costs for materials. The Arbuckle Pipeline will have the capacity to transport 160 MBbl/d of unfractionated NGLs, expandable to 210 MBbl/d with additional pump facilities, and will connect our existing Mid-Continent infrastructure with our fractionation facility in Mont Belvieu, Texas, and other Gulf Coast region fractionators. We have supply commitments from producers for 65 MBbl/d and indications of interest with other producers that could add an additional 145 MBbl/d of supply within the next three to five years. These additional supply commitments are in various stages of negotiation. Construction permits from various federal, state and local regulatory bodies have been received. Construction began in the third quarter of 2008 and is expected to be completed in the first quarter of 2009. This project is in our Natural Gas Liquids Pipelines segment.

Williston Basin Gas Processing Plant Expansion - In March 2007, we announced the expansion of our Grasslands natural gas processing facility in North Dakota, currently estimated to cost in the range of $40 million to $45 million, excluding AFUDC, which remains unchanged from the previous quarter. Our estimated project costs increased from $30 million primarily as a result of higher contract labor and equipment costs. The Grasslands facility is our largest natural gas processing plant in the Williston Basin. The expansion increases processing capacity to approximately 100 MMcf/d from its current capacity of 63 MMcf/d and increases fractionation capacity to approximately 12 MBbl/d from 8 MBbl/d. The expansion project is expected to be online in the fourth quarter of 2008. This project is in our Natural Gas Gathering and Processing segment.

Fort Union Gas Gathering Expansion - In January 2007, Fort Union Gas Gathering announced plans to double its existing gathering pipeline capacity by adding 148 miles of new gathering lines, resulting in approximately 649 MMcf/d of additional capacity in the Powder River basin of Wyoming. The expansion occurred in two phases and is currently expected to cost in the range of $120 million to $130 million, excluding AFUDC, which was primarily financed within the Fort Union Gas Gathering partnership. Any cost overruns are covered through escalation clauses to preserve the original economics of the project. Phase I, with more than 200 MMcf/d capacity, was placed in service during the fourth quarter of 2007. Phase II, with approximately 450 MMcf/d capacity, was completed in July 2008. The additional capacity has been fully subscribed for 10 years. We own approximately 37 percent of Fort Union Gas Gathering. This investment is in our Natural Gas Gathering and Processing segment and is accounted for under the equity method of accounting.

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Guardian Pipeline Expansion and Extension - In December 2007, Guardian Pipeline received and accepted the certificate of public convenience and necessity issued by the FERC for its expansion and extension project. The certificate authorizes us to construct, install and operate approximately 119 miles of a 20-inch and 30-inch natural gas transportation pipeline with a capacity to transport 537 MMcf/d of natural gas north from Ixonia, Wisconsin, to the Green Bay, Wisconsin, area. The project is supported by 15-year shipper commitments with We Energies and Wisconsin Public Service Corporation, and the capacity has been fully subscribed. The project is currently estimated to cost in the range of $277 million to $305 million, excluding AFUDC, which remains unchanged from the previous quarter. Our estimated project costs increased from our initial estimate of $241 million in 2006, which excluded AFUDC, primarily due to weather delays, construction in environmentally sensitive areas, rocky terrain and escalating costs associated with crop damage and condemnation costs. We received the notice to proceed from the FERC in May 2008. The pipeline is currently projected to be in service in the fourth quarter of 2008. This project is in our Natural Gas Pipelines segment.

IMPACT OF NEW ACCOUNTING STANDARDS

Information about the impact of the following new accounting standards is included in Note A of the Notes to Consolidated Financial Statements in this Quarterly Report on Form 10-Q:

- Statement 157, “Fair Value Measurements,” and related FASB Staff Position (FSP) 157-2, “Effective Date of FASB Statement No. 157,” and FSP 157-3, “Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active,”
- Statement 159, “The Fair Value Option for Financial Assets and Financial Liabilities,”
- FASB Staff Position No. FIN 39-1, “Amendment of FASB Interpretation No. 39,”
- Statement 141R, “Business Combinations,”
- Statement 160, “Noncontrolling Interests in Consolidated Financial Statements - an amendment of ARB No. 51,”
- Statement 161, “Disclosures about Derivative Instruments and Hedging Activities - an amendment to FASB Statement No. 133,” and
- EITF 07-4, “Application of the Two-Class Method under FASB Statement No. 128 to Master Limited Partnerships.”

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of our consolidated financial statements and related disclosures in accordance with GAAP requires us to make estimates and assumptions with respect to values or conditions that cannot be known with certainty that affect the reported amount of assets and liabilities, and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements. These estimates and assumptions also affect the reported amounts of revenues and expenses during the reporting period. Although we believe these estimates and assumptions are reasonable, actual results could differ from our estimates.

Information about our critical accounting estimates is included below and under Item 7, Management’s Discussion and Analysis of Financial Condition and Results of Operations, “Critical Accounting Policies and Estimates,” in our Annual Report on Form 10-K for the year ended December 31, 2007.

Impairment of Goodwill and Intangible Assets - We apply the provisions of Statement 142, “Goodwill and Other Intangible Assets,” and perform our annual impairment test on July 1. There were no impairment charges resulting from our July 1, 2008, impairment testing, and no events indicating an impairment have occurred subsequent to that date.

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FINANCIAL RESULTS AND OPERATING INFORMATION

Consolidated Operations

Selected Financial Results - The following table sets forth certain selected consolidated financial results for the periods indicated.

Financial Results	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
	(Thousands of dollars)			
Revenues	**$2,241,107**	$1,410,257	**$6,444,034**	$3,954,245
Cost of sales and fuel	**1,915,707**	1,196,373	**5,569,176**	3,317,421
Net margin	**325,400**	213,884	**874,858**	636,824
Operating costs	**97,488**	80,079	**272,728**	237,383
Depreciation and amortization	**30,408**	28,800	**90,383**	84,326
Gain (loss) on sale of assets	**22**	111	**50**	1,935
Operating income	**$ 197,526**	$ 105,116	**$ 511,797**	$ 317,050
Equity earnings from investments	**$ 29,412**	$ 22,162	**$ 74,805**	$ 64,975
Allowance for equity funds used during construction	**$ 15,616**	$ 3,691	**$ 35,788**	$ 6,686
Other income (expense)	**$ (4,794)**	$ 780	**$ (4,227)**	$ 4,234
Interest expense	**$ (34,447)**	$ (33,510)	**$ (107,681)**	$ (99,313)

Operating Results - Net margin increased for the three and nine months ended September 30, 2008, compared with the same periods last year, primarily due to the following:

- wider NGL product price differentials, increased NGL gathering and fractionation volumes and certain operational measurement gains, primarily at NGL storage caverns, in our Natural Gas Liquids Gathering and Fractionation segment,
- higher realized commodity prices, higher volumes sold and processed, and improved contractual terms in our Natural Gas Gathering and Processing segment,
- incremental net margin in our Natural Gas Liquids Pipelines segment from the assets acquired from Kinder Morgan in October 2007, and
- increased transportation and storage margins as a result of the impact of higher natural gas prices on retained fuel and new and renegotiated storage contracts in our Natural Gas Pipelines segment.

Operating costs increased for the three and nine months ended September 30, 2008, compared with the same periods last year, primarily due to incremental operating expenses associated with the assets acquired from Kinder Morgan and higher employee-related costs. Operating costs also increased due to costs associated with the startup of our newly expanded Bushton fractionator.

Depreciation and amortization increased for the three and nine months ended September 30, 2008, compared with the same periods last year, primarily due to depreciation expense associated with our completed capital projects and the assets acquired from Kinder Morgan.

Equity earnings from investments increased for the three and nine months ended September 30, 2008, compared with the same periods last year, primarily due to a gain on the sale of Bison Pipeline LLC by Northern Border Pipeline and higher gathering revenues in our various investments, partially offset by reduced throughput on Northern Border Pipeline. We own a 50 percent equity interest in Northern Border Pipeline.

Allowance for equity funds used during construction increased for the three and nine months ended September 30, 2008, compared with the same periods last year, due to increased spending for our capital projects, which are discussed beginning on page 21.

Other income (expense) fluctuated for the three and nine months ended September 30, 2008, compared with the same periods last year, primarily due to investment gains (losses).

Additional information regarding our results of operations is provided in the following discussion of operating results for each of our segments.

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Natural Gas Gathering and Processing

Overview - Our Natural Gas Gathering and Processing segment's operations include gathering of natural gas production from crude oil and natural gas wells. We gather unprocessed natural gas in the Mid-Continent region, which includes the Anadarko Basin of Oklahoma and the Hugoton and Central Kansas Uplift Basins of Kansas. We also gather unprocessed natural gas in two producing basins in the Rocky Mountain region: the Williston Basin, which spans portions of Montana, North Dakota and the Canadian province of Saskatchewan, and the Powder River Basin of Wyoming.

Through gathering systems, unprocessed natural gas volumes are aggregated for removal of water vapor, solids and other contaminants and to extract NGLs in order to provide marketable natural gas, commonly referred to as residue gas. When the NGLs are separated from the unprocessed natural gas at the processing plants, the NGLs are generally in the form of a mixed, unfractionated NGL stream. This unfractionated NGL stream is generally shipped to fractionators, where by applying heat and pressure, the unfractionated NGL stream is separated into marketable purity products, such as ethane/propane mix, propane, iso-butane, normal butane and natural gasoline (collectively, NGL products). Revenues for this segment are primarily derived from percent-of-proceeds (POP), fee and keep-whole contracts. Under a POP contract, we retain a portion of sales proceeds from the commodity sales for our services. With a fee-based contract, we charge a fee for our services, and with the keep-whole contract, we retain the NGLs as our fee for service and return to the producer an equivalent quantity of residue gas containing the same amount of Btus as the unprocessed natural gas that was delivered to us. Our natural gas and NGL products are sold to affiliates and a diverse customer base.

Selected Financial Results and Operating Information - The following tables set forth certain selected financial results and operating information for our Natural Gas Gathering and Processing segment for the periods indicated.

	Three Months Ended September 30,		Nine Months Ended September 30,	
Financial Results	**2008**	**2007**	**2008**	**2007**
	(Thousands of dollars)			
NGL and condensate sales	**$ 249,246**	$ 168,668	**$ 720,185**	$455,122
Residue gas sales	**209,734**	143,956	**636,980**	472,340
Gathering, compression, dehydration and processing fees and other revenues	**38,895**	36,327	**116,013**	107,127
Cost of sales and fuel	**386,155**	261,326	**1,136,432**	785,193
Net margin	**111,720**	87,625	**336,746**	249,396
Operating costs	**35,651**	31,808	**101,538**	96,399
Depreciation and amortization	**12,533**	11,277	**36,431**	33,544
Gain (loss) on sale of assets	**2**	10	**(3)**	1,823
Operating income	**$ 63,538**	$ 44,550	**$ 198,774**	$121,276
Equity earnings from investments	**$ 8,819**	$ 6,180	**$ 23,989**	$ 19,518

	Three Months Ended September 30,		Nine Months Ended September 30,	
Operating Information	**2008**	**2007**	**2008**	**2007**
Natural gas gathered *(BBtu/d)*	**1,146**	1,170	**1,174**	1,168
Natural gas processed *(BBtu/d)*	**649**	617	**641**	615
NGL sales *(MBbl/d)*	**39**	37	**39**	37
Residue gas sales *(BBtu/d)*	**281**	289	**280**	279
Capital expenditures *(Thousands of dollars)*	**$ 35,769**	$ 32,307	**$ 98,604**	$ 72,235
Realized composite NGL sales price *($/gallon)*	**$ 1.51**	$ 1.09	**$ 1.44**	$ 0.97
Realized condensate sales price *($/Bbl)*	**$ 99.61**	$ 69.05	**$ 96.91**	$ 61.25
Realized residue gas sales price *($/MMBtu)*	**$ 8.33**	$ 5.41	**$ 8.39**	$ 6.20
Realized gross processing spread *($/MMBtu)*	**$ 6.69**	$ 5.54	**$ 6.94**	$ 4.56

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	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	**2007**	**2008**	**2007**
Percent of proceeds				
Wellhead purchases *(MMBtu/d)*	**65,804**	76,841	**68,564**	86,361
NGL sales *(Bbl/d)*	**5,948**	5,680	**6,053**	5,911
Residue gas sales *(MMBtu/d)*	**42,119**	34,691	**38,570**	32,252
Condensate sales *(Bbl/d)*	**709**	681	**964**	695
Percentage of total net margin	**64%**	53%	**62%**	56%
Fee-based				
Wellhead volumes *(MMBtu/d)*	**1,145,656**	1,170,030	**1,173,894**	1,168,360
Average rate *($/MMBtu)*	**$ 0.27**	$ 0.26	**$ 0.26**	$ 0.26
Percentage of total net margin	**22%**	32%	**23%**	32%
Keep-whole				
NGL shrink *(MMBtu/d)*	**20,016**	22,056	**21,978**	23,555
Plant fuel *(MMBtu/d)*	**2,106**	2,605	**2,301**	2,785
Condensate shrink *(MMBtu/d)*	**1,574**	1,733	**1,941**	2,299
Condensate sales *(Bbl/d)*	**318**	351	**393**	465
Percentage of total net margin	**14%**	15%	**15%**	12%

Operating Results - Net margin increased $24.1 million for the three months ended September 30, 2008, compared with the same period last year, primarily due to the following:

- an increase of $18.3 million due to higher realized commodity prices,
- an increase of $3.4 million due to improved contractual terms, and
- an increase of $2.3 million due to higher volumes sold and processed.

Net margin increased $87.4 million for the nine months ended September 30, 2008, compared with the same period last year, primarily due to the following:

- an increase of $66.2 million due to higher realized commodity prices,
- an increase of $11.5 million due to higher volumes sold and processed, and
- an increase of $9.7 million due to improved contractual terms.

During September 2008, the disruption in the Gulf Coast area related to Hurricane Ike limited our ability to process and deliver natural gas and NGL volumes from our Mid-Continent processing plants. Without this volume reduction, we estimate net margin would have been approximately $1.8 million higher.

Operating costs increased $3.8 million for the three months ended September 30, 2008, compared with the same period last year, primarily due to increased employee-related costs and increased costs for chemicals and maintenance parts, partially offset by decreased equipment lease costs associated with the Bushton Plant.

Operating costs increased $5.1 million for the nine months ended September 30, 2008, compared with the same period last year, primarily due to increased employee-related costs, increased costs for chemicals and maintenance parts, and a favorable legal settlement received in June 2007, which reduced legal costs for the nine months ended September 30, 2007. These increases were partially offset by decreased equipment lease costs in 2008 associated with the Bushton Plant.

Depreciation and amortization increased $1.3 million and $2.9 million for the three- and nine-month periods in 2008, respectively, primarily as a result of depreciation expense associated with our completed capital projects.

The increase in equity earnings from investments for the three- and nine-month periods is driven primarily by higher gathering revenues in our various investments.

The increase in capital expenditures for the three and nine months ended September 30, 2008, compared with the same periods last year, is driven primarily by our increased growth activities, primarily in the Rocky Mountain region.

Our Natural Gas Gathering and Processing segment is exposed to commodity price risk, primarily from NGLs, as a result of our contractual obligations for services provided. A small percentage of our services, based on volume, is provided through keep-whole arrangements. See discussion regarding our commodity price risk beginning on page 38 under “Commodity Price Risk” in Item 3, Quantitative and Qualitative Disclosures about Market Risk.

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Natural Gas Pipelines

Overview - Our Natural Gas Pipelines segment primarily operates regulated natural gas transmission pipelines, natural gas storage facilities, and non-processable natural gas gathering facilities. We also provide interstate natural gas transportation and storage service in accordance with Section 311(a) of the Natural Gas Policy Act.

Our interstate natural gas pipeline assets transport natural gas through FERC-regulated interstate natural gas pipelines in Montana, North Dakota, South Dakota, Minnesota, Wisconsin, Iowa, Illinois, Indiana, Kentucky, Tennessee, Oklahoma, Texas and New Mexico. Our interstate pipelines include Midwestern Gas Transmission, Guardian Pipeline, Viking Gas Transmission Company, OkTex Pipeline and a 50 percent equity interest in Northern Border Pipeline.

Our intrastate natural gas pipeline assets in Oklahoma have access to the major natural gas producing areas and transport natural gas throughout the state. We also have access to the major natural gas producing area in south central Kansas. In Texas, our intrastate natural gas pipelines are connected to the major natural gas producing areas in the Texas panhandle and the Permian Basin, and transport natural gas to the Waha Hub, where other pipelines may be accessed for transportation east to the Houston Ship Channel market, north into the Mid-Continent market and west to the California market.

We own or lease storage capacity in underground natural gas storage facilities in Oklahoma, Kansas and Texas.

Our transportation contracts for our regulated natural gas activities are based upon rates stated in our tariffs. Tariffs specify the maximum rates customers can be charged, which can be discounted to meet competition if necessary, and the general terms and conditions for pipeline transportation service, which are established at FERC or appropriate state jurisdictional agency proceedings known as rate cases. In Texas and Kansas, natural gas storage service is a fee business that may be regulated by the state in which the facility operates and by the FERC for certain types of services. In Oklahoma, natural gas gathering and natural gas storage operations are not subject to rate regulation and have market-based rate authority from the FERC for certain types of services.

Selected Financial Results and Operating Information - The following tables set forth certain selected financial results and operating information for our Natural Gas Pipelines segment for the periods indicated.

Financial Results	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
	(Thousands of dollars)			
Transportation revenues	**$ 59,190**	$ 54,845	**$184,454**	$169,426
Storage revenues	**17,054**	13,579	**49,324**	40,984
Gas sales and other revenues	**10,446**	4,940	**32,880**	9,315
Cost of sales	**20,928**	13,117	**70,485**	40,045
Net margin	**65,762**	60,247	**196,173**	179,680
Operating costs	**23,852**	24,109	**67,900**	69,953
Depreciation and amortization	**8,607**	8,089	**25,547**	24,246
Gain (loss) on sale of assets	**—**	73	**(18)**	79
Operating income	**$ 33,303**	$ 28,122	**$102,708**	$ 85,560
Equity earnings from investments	**$ 20,207**	$ 16,493	**$ 49,421**	$ 45,275
Allowance for equity funds used during construction	**$ 3,822**	$ 1,005	**$ 8,304**	$ 2,110

Operating Information (a)	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
Natural gas transported *(MMcf/d)*	**3,500**	3,378	**3,637**	3,524
Average natural gas price Mid-Continent region (*$/MMBtu*)	**$ 8.44**	$ 5.42	**$ 8.27**	$ 6.08
Capital expenditures *(Thousands of dollars)*	**$ 107,822**	$ 44,561	**$159,810**	$ 90,635

(a) - Includes volumes for consolidated entities only.

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Operating Results - Net margin increased $5.5 million for the three months ended September 30, 2008, compared with the same period last year, primarily due to:

- an increase of $3.4 million due to higher natural gas transportation margins, primarily as a result of the impact of higher natural gas prices on retained fuel, and
- an increase of $1.1 million due to increased operational natural gas inventory sales.

Net margin increased $16.5 million for the nine months ended September 30, 2008, compared with the same period last year, primarily due to:

- an increase of $8.5 million due to higher natural gas transportation margins, primarily as a result of the impact of higher natural gas prices on retained fuel,
- an increase of $4.7 million due to higher natural gas storage margins, primarily related to new and renegotiated natural gas storage contracts and the higher natural gas price impact on retained fuel, and
- an increase of $3.0 million due to increased operational natural gas inventory sales.

Operating costs decreased $2.1 million for the nine months ended September 30, 2008, compared with the same period last year, primarily due to decreased general taxes and lower general operating costs.

Depreciation and amortization increased for the three- and nine-month periods, primarily as a result of depreciation expense associated with our completed capital projects.

Equity earnings from investments increased $3.7 million and $4.1 million for the three- and nine-month periods in 2008, respectively, primarily due to an $8.3 million gain on the sale of Bison Pipeline LLC by Northern Border Pipeline, partially offset by reduced throughput on Northern Border Pipeline. We own a 50 percent equity interest in Northern Border Pipeline.

The increase in allowance for equity funds used during construction and capital expenditures for the three and nine months ended September 30, 2008, compared with the same periods last year, is driven primarily by increased spending for our capital projects, which are discussed beginning on page 21.

Natural Gas Liquids Gathering and Fractionation

Overview - Our Natural Gas Liquids Gathering and Fractionation segment primarily gathers, treats and fractionates NGLs produced by natural gas processing plants located in Oklahoma, Kansas, the Texas panhandle and the Texas Gulf Coast, and stores and markets NGL products. We purchase NGLs and condensate from third parties as well as our Natural Gas Gathering and Processing segment. We connect the NGL production basins in Oklahoma, Kansas and the Texas panhandle with the key natural gas liquids market centers in Conway, Kansas, and Mont Belvieu, Texas.

Most natural gas produced at the wellhead contains a mixture of NGL components, such as ethane, propane, iso-butane, normal butane and natural gasoline. Natural gas processing plants remove the NGLs from the natural gas stream to realize the higher economic value of the NGLs and to meet natural gas pipeline quality specifications, which limit NGLs in the natural gas stream due to liquid and Btu content. The NGLs that are separated from the natural gas stream at the natural gas processing plants remain in a mixed, unfractionated form until they are gathered, primarily by pipeline, and delivered to our fractionators. A fractionator, by applying heat and pressure, separates the unfractionated NGL stream into marketable purity products, such as ethane/propane mix, propane, iso-butane, normal butane and natural gasoline (collectively, NGL products). These NGL products are then stored and/or distributed to our customers, such as petrochemical plants, heating fuel users and refineries.

Revenues for this segment are primarily derived from exchange services, optimization, isomerization and storage.

- Our exchange services business collects fees to gather, fractionate and treat unfractionated NGLs, thereby converting them into NGL products that are stored and shipped to a market center or customer-designated location.
- Our optimization business utilizes our assets, contract portfolio and market knowledge to capture locational and seasonal price differentials. We move NGL products between Conway, Kansas, and Mont Belvieu, Texas, in order to capture the locational price differentials between the two market centers. Our NGL storage facilities are also utilized to capture seasonal price variances.
- Our isomerization business captures the price differential when normal butane is converted into the more valuable iso-butane at an isomerization unit in Conway, Kansas. Iso-butane is used in the refining industry to upgrade the octane of motor gasoline.
- Our storage business collects fees to store NGLs at our Mid-Continent and Mont Belvieu, Texas, facilities.

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Selected Financial Results and Operating Information - The following tables set forth certain selected financial results and operating information for our Natural Gas Liquids Gathering and Fractionation segment for the periods indicated.

	Three Months Ended September 30,		Nine Months Ended September 30,	
Financial Results	**2008**	**2007**	**2008**	**2007**
	(Thousands of dollars)			
NGL and condensate sales	**$1,759,141**	$1,054,759	**$5,037,563**	$2,851,363
Storage and fractionation revenues	**84,181**	65,338	**251,383**	197,301
Cost of sales and fuel	**1,724,692**	1,071,270	**5,033,452**	2,893,369
Net margin	**118,630**	48,827	**255,494**	155,295
Operating costs	**22,954**	17,787	**61,575**	49,387
Depreciation and amortization	**5,901**	6,439	**17,188**	17,525
Gain (loss) on sale of assets	**13**	27	**31**	31
Operating income	**$ 89,788**	$ 24,628	**$ 176,762**	$ 88,414

	Three Months Ended September 30,		Nine Months Ended September 30,	
Operating Information	**2008**	**2007**	**2008**	**2007**
NGLs gathered *(MBbl/d)*	**243**	232	**249**	222
NGL sales *(MBbl/d)*	**273**	223	**275**	221
NGLs fractionated *(MBbl/d)*	**375**	370	**379**	346
Conway-to-Mont Belvieu OPIS average price differential Ethane *($/gallon)*	**$ 0.24**	$ 0.05	**$ 0.15**	$ 0.05
Capital expenditures *(Thousands of dollars)*	**$ 52,558**	$ 20,645	**$ 137,177**	$ 43,234

Operating Results - Net margin increased $69.8 million for the three months ended September 30, 2008, compared with the same period last year, primarily due to the following:

- an increase of $43.7 million due to significantly wider product price differentials between Conway, Kansas, and Mont Belvieu, Texas,
- an increase of $13.3 million from certain operational measurement gains, primarily at NGL storage caverns,
- an increase of $12.5 million due to higher exchange margins, primarily driven by increased gathering and fractionation volumes, and
- an increase of $3.3 million due to higher isomerization volumes and wider iso-butane-to-normal butane price differentials.

Net margin increased $100.2 million for the nine months ended September 30, 2008, compared with the same period last year, primarily due to the following:

- an increase of $59.3 million due to wider product price differentials between Conway, Kansas, and Mont Belvieu, Texas,
- an increase of $31.8 million due to higher exchange margins, primarily driven by increased gathering and fractionation volumes,
- an increase of $11.4 million from certain operational measurement gains, primarily at NGL storage caverns, and
- an increase of $2.5 million due to higher storage margins in our Mid-Continent storage business.

During September 2008, Hurricane Ike caused disruptions to our gathering and fractionation operations in the Mid-Continent and Gulf Coast regions. Without this disruption, we estimate net margin would have been approximately $3.8 million higher.

Operating costs increased $5.2 million and $12.2 million, respectively, for the three- and nine-month periods, primarily due to increased lease costs for the Bushton facility, increased costs associated with the startup of our newly expanded Bushton fractionator, increased employee-related costs and increased operating expenses at our fractionators due to increased utilization.

As noted in the "Operating Information" table above, product price differentials were significantly higher in 2008 than 2007. We began experiencing lower price differentials beginning in October 2008. However, the price differentials we are currently experiencing have remained above the three-year average Conway-to-Mont Belvieu price differential for ethane of $0.05 per gallon.

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The increase in capital expenditures for the three and nine months ended September 30, 2008, compared with the same periods last year, is driven primarily by our capital projects, which are discussed beginning on page 21.

Natural Gas Liquids Pipelines

Overview - Our Natural Gas Liquids Pipelines segment primarily operates FERC-regulated natural gas liquids gathering and distribution pipelines and associated above- and below-ground storage facilities. Our natural gas liquids gathering pipelines deliver unfractionated NGLs gathered in Oklahoma, Kansas, the Texas panhandle and the Rocky Mountain region to our Natural Gas Liquids Gathering and Fractionation segment's Mid-Continent fractionation facilities. Our natural gas liquids distribution pipelines deliver NGL products to the natural gas liquids market hubs in Conway, Kansas, and Mont Belvieu, Texas. Through our acquisition of the natural gas liquids assets from Kinder Morgan, we acquired terminal and storage facilities, as well as natural gas liquids and refined petroleum products pipelines that connect our Mid-Continent assets with Midwest markets, including Chicago, Illinois. Our natural gas liquids gathering and distribution pipelines operate in Oklahoma, Kansas, Nebraska, Missouri, Iowa, Illinois, Indiana, Texas, Wyoming and Colorado. We have terminal and storage facilities in Missouri, Nebraska, Iowa and Illinois.

Revenues for this segment are primarily derived from transporting product under our FERC-regulated tariffs. Tariffs specify the rates we can charge our customers and the general terms and conditions for NGL transportation service on our pipelines. Our tariffs include specifications regarding the receipt and delivery of NGLs at points along the pipeline systems. We generally charge tariff rates under a FERC-approved indexing methodology, which allows charging rates up to a prescribed ceiling that changes annually based on the year-to-year change in the Producer Price Index for finished goods. The FERC also permits interstate natural gas liquids pipelines to support rates by using a cost-of-service methodology, competitive market price or an agreement with a pipeline's non-affiliated shipper.

Selected Financial Results and Operating Information - The following tables set forth certain selected financial results and operating information for our Natural Gas Liquids Pipelines segment for the periods indicated.

	Three Months Ended September 30,		Nine Months Ended September 30,	
Financial Results	**2008**	**2007**	**2008**	**2007**
	(Thousands of dollars)			
Transportation and gathering revenues	**$ 33,282**	$ 19,671	**$ 101,284**	$ 56,181
Storage revenues	**914**	—	**3,943**	—
NGL sales and other revenues	**350**	1	**2,778**	13
Cost of sales and fuel	**4,792**	1,691	**19,525**	4,261
Net margin	**29,754**	17,981	**88,480**	51,933
Operating costs	**14,986**	5,648	**42,171**	16,551
Depreciation and amortization	**3,361**	2,987	**11,200**	8,990
Gain (loss) on sale of assets	**7**	1	**8**	2
Operating income	**$ 11,414**	$ 9,347	**$ 35,117**	$ 26,394
Equity earnings from investments	**$ 386**	$ (511)	**$ 1,395**	$ 182
Allowance for equity funds used during construction	**$ 11,794**	$ 2,686	**$ 27,484**	$ 4,576

	Three Months Ended September 30,		Nine Months Ended September 30,	
Operating Information	**2008**	**2007**	**2008**	**2007**
NGLs transported *(MBbl/d)*	**331**	225	**314**	219
NGLs gathered *(MBbl/d)*	**88**	84	**92**	78
Capital expenditures *(Thousands of dollars)*	**$ 139,431**	$ 104,428	**$ 464,511**	$ 202,222

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Operating Results - Net margin increased $11.8 million for the three months ended September 30, 2008, compared with the same period last year, primarily due to an increase of $12.0 million in incremental margin from the assets acquired from Kinder Morgan in October 2007.

Net margin increased $36.5 million for the nine months ended September 30, 2008, compared with the same period last year, primarily due to the following:

- an increase of $34.0 million in incremental margin from the assets acquired from Kinder Morgan in October 2007 and
- an increase of $2.5 million due to increased throughput from new supply connections and increased production volumes from existing supply connections to our natural gas liquids gathering pipelines.

During September 2008, the disruption in the Gulf Coast area related to Hurricane Ike reduced transportation and gathering volumes on our pipeline assets between the Mid-Continent fractionation facilities and the natural gas liquids market hubs of Conway, Kansas, and Mont Belvieu, Texas. Without this volume reduction, we estimate net margin would have been approximately $2.2 million higher.

Operating costs increased $9.3 million for the three months ended September 30, 2008, compared with the same period last year, primarily due to $7.3 million in incremental operating expenses associated with the assets acquired from Kinder Morgan, as well as higher employee-related costs and costs associated with the startup of Overland Pass Pipeline operations.

Operating costs increased $25.6 million for the nine months ended September 30, 2008, compared with the same period last year, primarily due to $20.6 million in incremental operating expenses associated with the assets acquired from Kinder Morgan, as well as higher employee-related costs, outside services, and costs associated with the startup of Overland Pass Pipeline operations.

Depreciation and amortization increased $2.2 million for the nine months ended September 30, 2008, primarily due to the assets acquired from Kinder Morgan.

Equity earnings from investments increased $1.2 million for the nine months ended September 30, 2008, compared with the same period last year, primarily due to equity earnings from our investment in Heartland, which we acquired from Kinder Morgan in October 2007.

The increase in allowance for equity funds used during construction and capital expenditures for the three and nine months ended September 30, 2008, compared with the same periods last year, is driven primarily by our growth activities. See discussion of our capital projects beginning on page 21.

Other

In the second quarter of 2008, we started the decommissioning of the Black Mesa Pipeline, Inc. The affected land owners have been informed of this decision. We do not expect the decommissioning to have a material impact on our consolidated financial statements.

Contingencies

Legal Proceedings - We are a party to various litigation matters and claims that are in the normal course of our operations. While the results of litigation and claims cannot be predicted with certainty, we believe the final outcome of such matters will not have a material adverse effect on our consolidated results of operations, financial position or liquidity.

FERC Matter - As a result of an internal review of a transaction that was brought to the attention of one of our affiliates by a third party, we conducted an internal review of transactions that may have violated FERC natural gas capacity release rules or related rules and determined that there were transactions that should have been disclosed to the FERC. We notified the FERC of this review and filed a report with the FERC regarding these transactions in March 2008. We are cooperating fully with the FERC and have taken steps to ensure that current and future transactions comply with applicable FERC regulations. We are unable to predict the outcome of any FERC action in this matter. At this time, we do not believe that penalties associated with potential violations will have a material impact on our results of operations, financial position or liquidity.

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LIQUIDITY AND CAPITAL RESOURCES

General - Our principal sources of liquidity include cash generated from operating activities, bank credit facilities, debt issuances and the sale of common units. We fund our operating expenses, debt service and cash distributions to our limited partners and general partner primarily with operating cash flow. We have no material guarantees of debt or other similar commitments to unaffiliated parties.

Part of our growth strategy is to expand our existing businesses and strategically acquire related businesses that strengthen and complement our existing assets. Capital resources for acquisitions and maintenance and growth expenditures may be funded by a variety of sources, including those listed above as our principal sources of liquidity. Beginning in 2007 and continuing in 2008, the capital markets have been impacted by macroeconomic, liquidity, credit and other recessionary concerns. During this period, we have continued to have access to our Partnership Credit Agreement to fund our short-term liquidity needs. In 2008, we issued common units and received additional contributions from our general partner. See discussion below under “Equity Issuance.” We also issued $600 million of long-term debt in September 2007. Our ability to continue to access capital markets for debt and equity financing under reasonable terms depends on our financial condition, credit ratings and market conditions. We anticipate that our existing capital resources, ability to obtain financing and cash flow generated from future operations will enable us to maintain our current level of operations and our planned operations, including capital expenditures, for the remainder of 2008 and into 2009.

During the nine months ended September 30, 2008 and 2007, our capital expenditures were financed through operating cash flows and short- and long-term debt. For the nine months ended September 30, 2008, our capital expenditures were also financed through the issuance of common units. Capital expenditures for the first nine months of 2008 were $860.2 million, compared with $408.4 million for the same period in 2007, exclusive of acquisitions. The increase in capital expenditures for 2008, compared with 2007, is driven primarily by our capital projects, which are discussed beginning on page 21.

Financing - Financing is provided through available cash, our Partnership Credit Agreement, the issuance of common units or long-term debt. Other options to obtain financing include, but are not limited to, issuance of convertible debt securities, asset securitization and sale/leaseback of facilities.

The total amount of short-term borrowings authorized by our general partner’s Board of Directors is $1.5 billion. At September 30, 2008, we had $280 million of borrowings outstanding and $720 million available under our Partnership Credit Agreement and available cash and cash equivalents of approximately $15.8 million. As of September 30, 2008, we could have issued $1.4 billion of additional short- and long-term debt under the most restrictive provisions contained in our Partnership Credit Agreement.

We have a $15 million Senior Unsecured Letter of Credit Facility and Reimbursement Agreement with Wells Fargo Bank, N.A., of which $12 million is currently being used, and an agreement with Royal Bank of Canada, pursuant to which a $12 million letter of credit was issued. Both agreements are used to support various permits required by the KDHE for our ongoing business in Kansas.

Our Partnership Credit Agreement contains typical covenants as discussed in Note F of the Notes to Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2007. At September 30, 2008, we were in compliance with all covenants.

During the third and fourth quarters of 2008, the capital markets have been significantly impacted by a financial credit crisis. Because of these market conditions and to ensure we would have access to the capital required to fund our growth projects and working capital needs, we borrowed $590 million under our Partnership Credit Agreement in October 2008. With this borrowing, we had $870 million outstanding and $130 million available under our Partnership Credit Agreement at October 31, 2008. On that date, we also had approximately $396 million in available cash and cash equivalents. We will utilize these funds and remaining borrowing capacity, as well as operating cash flow, to fund our growth projects and working capital requirements for the remainder of 2008 and into 2009. The average interest rate on our short-term debt outstanding at October 31, 2008, was 4.22 percent, compared with a weighted average of 3.24 percent for the first nine months of 2008. Based on the forward LIBOR curve, we expect the interest rate on our short-term borrowings to increase in 2009, compared with 2008.

Equity Issuance - In March 2008, we completed a public offering of 2.5 million common units at $58.10 per common unit, generating net proceeds of approximately $140.4 million after deducting underwriting discounts but before offering expenses. In addition, we sold 5.4 million common units to ONEOK in a private placement, generating proceeds of approximately $303.2 million. In conjunction with the public offering of common units and the private placement, ONEOK Partners GP contributed $9.4 million in order to maintain its 2 percent general partner interest in us.

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In April 2008, we sold an additional 128,873 common units at $58.10 per common unit to the underwriters of the public offering upon the partial exercise of their option to purchase additional common units to cover over-allotments. We received net proceeds of approximately $7.2 million from the sale of the common units after deducting underwriting discounts but before offering expenses. In conjunction with the partial exercise by the underwriters, ONEOK Partners GP contributed $0.2 million in order to maintain its 2 percent general partner interest in us. As a result of these transactions, ONEOK now holds an aggregate 47.7 percent equity interest in us.

We used a portion of the proceeds from the sale of common units and the general partner contributions to repay borrowings under our Partnership Credit Agreement.

Capitalization Structure - The following table sets forth our capitalization structure for the periods indicated.

	September 30, 2008	December 31, 2007
Long-term Debt	**48%**	54%
Equity	**52%**	46%
Debt (including notes payable)	**50%**	55%
Equity	**50%**	45%

Credit Ratings - Our investment grade credit ratings as of September 30, 2008, are shown in the table below.

Rating Agency	Rating	Outlook
Moody’s	Baa2	Stable
S&P	BBB	Stable

Our credit ratings may be affected by a material change in our financial ratios or a material event affecting our business. The most common criteria for assessment of our credit ratings are the debt-to-EBITDA (earnings before interest, taxes, depreciation and amortization) ratio, interest coverage, business risk profile and liquidity. If our credit ratings were downgraded, the interest rates on our Partnership Credit Agreement borrowings would increase, resulting in an increase in our cost to borrow funds. An adverse rating change alone is not a default under our Partnership Credit Agreement.

Our $250 million and $225 million senior notes, due 2010 and 2011, respectively, contain provisions that require us to offer to repurchase the senior notes at par value if our Moody’s or S&P credit rating falls below investment grade (Baa3 for Moody’s or BBB- for S&P) and the investment grade rating is not reinstated within a period of 40 days. Further, the indentures governing our senior notes due 2010 and 2011 include an event of default upon acceleration of other indebtedness of $25 million or more and the indentures governing our senior notes due 2012, 2016, 2036 and 2037 include an event of default upon the acceleration of other indebtedness of $100 million or more that would be triggered by such an offer to repurchase. Such an event of default would entitle the trustee or the holders of 25 percent in aggregate principal amount of the outstanding senior notes due 2010, 2011, 2012, 2016, 2036 and 2037 to declare those notes immediately due and payable in full. We may not have sufficient cash on hand to repurchase and repay any accelerated senior notes, which may cause us to borrow money under our credit facilities or seek alternative financing sources to finance the repurchases and repayment. We could also face difficulties accessing capital or our borrowing costs could increase, impacting our ability to obtain financing for acquisitions or capital expenditures, to refinance indebtedness and to fulfill our debt obligations. A decline in our credit rating below investment grade may also require us to provide security to our counterparties in the form of cash, letters of credit or other negotiable instruments.

Other than the note repurchase obligations described above, we have determined that we do not have significant exposure to rating triggers in various other contracts and equipment leases. Rating triggers are defined as provisions that would create an automatic default or acceleration of indebtedness based on a change in our credit rating.

In the normal course of business, our counterparties provide us with secured and unsecured credit. In the event of a downgrade in our credit rating or a significant change in our counterparties’ evaluation of our credit worthiness, we could be asked to provide additional collateral.

Capital Expenditures - We classify expenditures that are expected to generate additional revenues or significant operating efficiencies as growth capital expenditures. Any remaining capital expenditures are classified as maintenance capital expenditures.

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The following table summarizes our 2008 projected growth and maintenance capital expenditures, excluding AFUDC.

2008 Projected Capital Expenditures	Growth	Maintenance	Total
	(Millions of dollars)		
Natural Gas Gathering and Processing	$ 128	$ 22	$ 150
Natural Gas Pipelines	224	21	245
Natural Gas Liquids Gathering and Fractionation	143	29	172
Natural Gas Liquids Pipelines	735	12	747
Total projected capital expenditures	$ 1,230	$ 84	$1,314

Additional information about our growth capital expenditures is included under “Capital Projects” beginning on page 21. Financing for our capital expenditures may include any, or a combination, of the following: cash from operations, borrowings under our Partnership Credit Agreement, and debt or equity offerings.

Investment in Northern Border Pipeline - Northern Border Pipeline anticipates an equity contribution of approximately $85 million will be required of its partners in 2009, of which our share will be approximately $43 million for our 50 percent equity interest.

Cash Distributions - We distribute 100 percent of our available cash, which generally consists of all cash receipts less adjustments for cash disbursements and net change to reserves, to our general and limited partners. Our income is allocated to our general partner and limited partners according to their partnership percentages of 2 percent and 98 percent, respectively. The effect of any incremental income allocations for incentive distributions to our general partner is calculated after the income allocation for the general partner’s partnership interest and before the income allocation to the limited partners.

The following table sets forth the distribution payments, including our general partner’s incentive distribution interests, for the periods indicated.

	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
	(Thousands of dollars)	
Common unitholders	**$ 161,852**	$ 137,801
Class B unitholder	**114,045**	108,387
General Partner	**56,193**	39,810

The following summarizes our quarterly cash distribution activity for 2008.

- In January 2008, we increased our cash distribution to $1.025 per unit for the fourth quarter of 2007. The distribution was paid on February 14, 2008, to unitholders of record on January 31, 2008.
- In April 2008, we increased our cash distribution to $1.04 per unit for the first quarter of 2008. The distribution was paid on May 15, 2008, to unitholders of record as of April 30, 2008.
- In July 2008, we increased our cash distribution to $1.06 per unit for the second quarter of 2008. The distribution was paid on August 14, 2008, to unitholders of record as of July 31, 2008.
- In October 2008, we increased our cash distribution to $1.08 per unit ($4.32 per unit on an annualized basis) for the third quarter of 2008. The distribution will be paid on November 14, 2008, to unitholders of record as of October 31, 2008.

Our general partner’s percentage interest in quarterly distributions increases after certain specified target levels are met. For additional information, see “Cash Distribution Policy” under Part II, Item 5, Market for Registrant’s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities, in our Annual Report on Form 10-K for the year ended December 31, 2007.

Commodity Prices - We are subject to commodity price volatility. Significant fluctuations in commodity prices may impact our overall liquidity due to the impact commodity price changes have on our cash flows from operating activities, including the impact on working capital for NGLs held in storage, margin requirements and certain energy-related receivables. We believe that our available credit and cash and cash equivalents are adequate to meet liquidity requirements associated with commodity price volatility. See discussion beginning on page 38 under “Commodity Price Risk” in Item 3, Quantitative and Qualitative Disclosures about Market Risk, for information on our hedging activities.

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ENVIRONMENTAL AND SAFETY MATTERS

Environmental Liabilities - We are subject to multiple environmental, historical and wildlife preservation laws and regulations affecting many aspects of our present and future operations. Regulated activities include those involving air emissions, storm water and wastewater discharges, handling and disposal of solid and hazardous wastes, hazardous materials transportation, and pipeline and facility construction. These laws and regulations require us to obtain and comply with a wide variety of environmental clearances, registrations, licenses, permits and other approvals. Failure to comply with these laws, regulations, permits and licenses may expose us to fines, penalties and/or interruptions in our operations that could be material to our results of operations. If an accidental leak or spill of hazardous substances or petroleum products occurs from our lines or facilities, in the process of transporting natural gas, NGLs, or refined products, or at any facility that we own, operate or otherwise use, we could be held jointly and severally liable for all resulting liabilities, including investigation and clean-up costs, which could materially affect our results of operations and cash flows. In addition, emission controls required under the federal Clean Air Act and other similar federal and state laws could require unexpected capital expenditures at our facilities. We cannot assure that existing environmental regulations will not be revised or that new regulations will not be adopted or become applicable to us. Revised or additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from customers, could have a material adverse effect on our business, financial condition and results of operations.

Our expenditures for environmental evaluation, mitigation and remediation to date have not been significant in relation to our results of operations, and there were no material effects upon earnings during the nine months ended September 30, 2008 or 2007, related to compliance with environmental regulations.

Pipeline Safety - We are subject to United States Department of Transportation regulations, including integrity management regulations. The Pipeline Safety Improvement Act requires pipeline companies to perform integrity assessments on pipeline segments that pass through densely populated areas or near specifically designated high consequence areas. To our knowledge, we are in compliance with all material requirements associated with the various pipeline safety regulations.

Air and Water Emissions - The federal Clean Air Act, the federal Clean Water Act and analogous state laws impose restrictions and controls regarding the discharge of pollutants into the air and water in the United States. Under the Clean Air Act, a federally enforceable operating permit is required for sources of significant air emissions. We may be required to incur certain capital expenditures for air pollution-control equipment in connection with obtaining or maintaining permits and approvals for sources of air emissions. The Clean Water Act imposes substantial potential liability for the removal and remediation of pollutants discharged to waters of the United States. To our knowledge, we are in compliance with all material requirements associated with the various regulations.

Chemical Site Security - The United States Department of Homeland Security (Homeland Security) released an interim rule in April 2007 that requires companies to provide reports on sites where certain chemicals, including many hydrocarbon products, are stored. After having received these reports, Homeland Security is identifying which sites are required to implement minimum security measures. Homeland Security is in the initial stages of implementing this rule, and the full extent to which the rule will require us to undertake additional expenditures for site security is uncertain at this point.

Climate Change - Our environmental and climate change strategy focuses on taking steps to minimize the impact of our operations on the environment. These strategies include: (i) developing and maintaining an accurate greenhouse gas emissions inventory, (ii) improving the efficiency of our various pipeline and gas processing facilities, (iii) following developing technologies for emission control, (iv) following developing technologies to capture carbon dioxide to keep it from reaching the atmosphere, and (v) analyzing options for future energy investment.

Currently, operating entities within our Partnership participate in the Processing and Transmission sectors of the United States Environmental Protection Agency's Natural Gas STAR Program to voluntarily reduce methane emissions. In addition, we continue to focus on maintaining low rates of lost and unaccounted for gas through expanded implementation of best practices to limit the release of methane during pipeline and facility maintenance and operations.

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CASH FLOW ANALYSIS

Operating Cash Flows - We use the indirect method to prepare our Consolidated Statements of Cash Flows. Under this method, we reconcile net income to cash flows provided by operating activities by adjusting net income for those items that impact net income but may not result in actual cash receipts or payments during the period. These reconciling items include depreciation and amortization, allowance for equity funds used during construction, gain on sale of assets, minority interests in income of consolidated subsidiaries, and undistributed earnings from equity investments in excess of distributions received.

Operating cash flows increased by $42.2 million for the nine months ended September 30, 2008, compared with the same period in 2007. The increase in our operating cash flow is primarily attributable to higher net income, adjusted for the non-cash items as discussed above. This increase was offset by a reduction in cash from changes in working capital. For more information on our results of operations, see “Financial Results and Operating Information” within Item 2.

Investing Cash Flows - Cash used in investing activities was $854.5 million for the nine months ended September 30, 2008, compared with $409.9 million for the same period in 2007. The increased use of cash was primarily due to increased capital expenditures related to our capital projects.

Financing Cash Flows - Cash provided by financing activities was $298.4 million for the nine months ended September 30, 2008, compared with $656.8 million for the same period in 2007.

During 2008, our concurrent public offering and private placement of common units generated proceeds of $450.2 million. In addition, ONEOK Partners GP contributed $9.5 million in order to maintain its 2 percent general partner interest in us. We used a portion of the proceeds and general partner contributions to repay borrowings under our revolving credit agreement.

Net borrowings totaled $180.0 million for the nine months ended September 30, 2008, compared with $359.0 million for the same period in 2007. Borrowings for both periods were primarily used to fund our ongoing capital projects. Net borrowings in 2008 include repayments, which were made with a portion of the proceeds provided by the public offering and private placement discussed above.

Cash distributions to our general and limited partners for 2008 were $332.1 million, compared with $286.0 million in the same period in 2007, an increase of $46.1 million. This increase was primarily due to the additional units outstanding during 2008, as a result of the concurrent public offering and private placement in March and April 2008, as well as cash distributions of $3.125 per unit for the nine months ended September 30, 2008, compared with $2.97 per unit paid in the same period in 2007.

During the third quarter of 2007, we completed an underwritten public offering of senior notes totaling $598 million in net proceeds, before offering expenses. This debt issuance, net of discounts, was used to repay borrowings under our revolving credit agreement in the fourth quarter of 2007 and finance the $300 million acquisition of assets, before working capital adjustments, from a subsidiary of Kinder Morgan in October 2007.

FORWARD-LOOKING STATEMENTS

Some of the statements contained and incorporated in this Quarterly Report on Form 10-Q are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities and Exchange Act of 1934, as amended. The forward-looking statements relate to our anticipated financial performance, management’s plans and objectives for our future operations, our business prospects, the outcome of regulatory and legal proceedings, market conditions and other matters. We make these forward-looking statements in reliance on the safe harbor protections provided under the Private Securities Litigation Reform Act of 1995. The following discussion is intended to identify important factors that could cause future outcomes to differ materially from those set forth in the forward-looking statements.

Forward-looking statements include the items identified in the preceding paragraph, the information concerning possible or assumed future results of our operations and other statements contained or incorporated in this Quarterly Report on Form 10-Q identified by words such as “anticipate,” “estimate,” “expect,” “project,” “intend,” “plan,” “believe,” “should,” “goal,” “forecast,” “could,” “may,” “continue,” “might,” “potential,” “scheduled” and other words and terms of similar meaning.

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You should not place undue reliance on forward-looking statements. Known and unknown risks, uncertainties and other factors may cause our actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by forward-looking statements. Those factors may affect our operations, markets, products, services and prices. In addition to any assumptions and other factors referred to specifically in connection with the forward-looking statements, factors that could cause our actual results to differ materially from those contemplated in any forward-looking statement include, among others, the following:

- the effects of weather and other natural phenomena on our operations, demand for our services and energy prices;
- competition from other United States and Canadian energy suppliers and transporters as well as alternative forms of energy;
- the capital intensive nature of our businesses;
- the profitability of assets or businesses acquired by us;
- risks of marketing, trading and hedging activities, including the risks of changes in energy prices or the financial condition of our counterparties;
- the uncertainty of estimates, including accruals and costs of environmental remediation;
- the timing and extent of changes in energy commodity prices;
- the effects of changes in governmental policies and regulatory actions, including changes with respect to income and other taxes, environmental compliance, climate change initiatives, authorized rates or recovery of gas and gas transportation costs;
- the impact on drilling and production by factors beyond our control, including the demand for natural gas and refinery-grade crude oil; producers' desire and ability to obtain necessary permits; reserve performance; and capacity constraints on the pipelines that transport crude oil, natural gas and NGLs from producing areas and our facilities;
- changes in demand for the use of natural gas because of market conditions caused by concerns about global warming;
- the impact of unforeseen changes in interest rates, equity markets, inflation rates, economic recession and other external factors over which we have no control;
- actions by rating agencies concerning the credit ratings of us or our general partner;
- the results of administrative proceedings and litigation, regulatory actions and receipt of expected clearances involving the OCC, KCC, Texas regulatory authorities or any other local, state or federal regulatory body, including the FERC;
- our ability to access capital at competitive rates or on terms acceptable to us;
- risks associated with adequate supply to our gathering, processing, fractionation and pipeline facilities, including production declines that outpace new drilling;
- the risk that material weaknesses or significant deficiencies in our internal control over financial reporting could emerge or that minor problems could become significant;
- the impact and outcome of pending and future litigation;
- the ability to market pipeline capacity on favorable terms, including the effects of:
  - future demand for and prices of natural gas and NGLs;
  - competitive conditions in the overall energy market;
  - availability of supplies of Canadian and United States natural gas; and
  - availability of additional storage capacity;
- performance of contractual obligations by our customers, service providers, contractors and shippers;
- the timely receipt of approval by applicable governmental entities for construction and operation of our pipeline and other projects and required regulatory clearances;
- our ability to acquire all necessary rights-of-way permits and consents in a timely manner, to promptly obtain all necessary materials and supplies required for construction, and to construct gathering, processing, storage, fractionation and transportation facilities without labor or contractor problems;
- the mechanical integrity of facilities operated;
- demand for our services in the proximity of our facilities;
- our ability to control operating costs;
- acts of nature, sabotage, terrorism or other similar acts that cause damage to our facilities or our suppliers' or shippers' facilities;
- economic climate and growth in the geographic areas in which we do business;
- the risk of a significant slowdown in growth or decline in the U.S. economy or the risk of delay in growth recovery in the U.S. economy, including increasing liquidity risks in U.S. credit markets;
- the impact of recently issued and future accounting pronouncements and other changes in accounting policies;

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- the possibility of future terrorist attacks or the possibility or occurrence of an outbreak of, or changes in, hostilities or changes in the political conditions in the Middle East and elsewhere;
- the risk of increased costs for insurance premiums, security or other items as a consequence of terrorist attacks;
- risks associated with pending or possible acquisitions and dispositions, including our ability to finance or integrate any such acquisitions and any regulatory delay or conditions imposed by regulatory bodies in connection with any such acquisitions and dispositions;
- the impact of unsold pipeline capacity being greater or less than expected;
- the ability to recover operating costs and amounts equivalent to income taxes, costs of property, plant and equipment and regulatory assets in our state and FERC-regulated rates;
- the composition and quality of the natural gas and NGLs we gather and process in our plants and transport on our pipelines;
- the efficiency of our plants in processing natural gas and extracting and fractionating NGLs;
- the impact of potential impairment charges;
- the risk inherent in the use of information systems in our respective businesses, implementation of new software and hardware, and the impact on the timeliness of information for financial reporting;
- our ability to control construction costs and completion schedules of our pipelines and other projects; and
- the risk factors listed in the reports we have filed and may file with the SEC, which are incorporated by reference.

These factors are not necessarily all of the important factors that could cause actual results to differ materially from those expressed in any of our forward-looking statements. Other factors could also have material adverse effects on our future results. These and other risks are described in greater detail in Part I, Item 1A, Risk Factors, in our Annual Report on Form 10-K for the year ended December 31, 2007. All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by these factors. Other than as required under securities laws, we undertake no obligation to update publicly any forward-looking statement whether as a result of new information, subsequent events or change in circumstances, expectations or otherwise.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Our quantitative and qualitative disclosures about market risk are consistent with those discussed in Part II, Item 7A, Quantitative and Qualitative Disclosures About Market Risk in our Annual Report on Form 10-K for the year ended December 31, 2007, except that beginning January 1, 2008, we determine the fair value of our derivative instruments in accordance with Statement 157. See Notes A and C of the Notes to Consolidated Financial Statements in this Quarterly Report on Form 10-Q for further discussion of Statement 157.

INTEREST RATE RISK

General - We are subject to the risk of interest rate fluctuation in the normal course of business. We manage interest rate risk through the use of fixed-rate debt, floating-rate debt and, at times, interest-rate swaps. At September 30, 2008, the interest rate on all of our long-term debt was fixed.

Fair Value Hedges - See Note D of the Notes to Consolidated Financial Statements in this Quarterly Report on Form 10-Q for discussion of interest-rate swaps and interest expense savings from terminated swaps.

Total interest expense savings from amortization of terminated swaps for 2008 will be $3.7 million, compared with total net swap savings of $2.5 million in 2007.

COMMODITY PRICE RISK

In our Natural Gas Gathering and Processing segment, we are exposed to commodity price risk, primarily NGLs, as a result of receiving commodities in exchange for our services. To a lesser extent, exposures arise from the relative price differential between NGLs and natural gas, or the gross processing spread, with respect to our keep-whole processing contracts. We are also exposed to the risk of price fluctuations and the cost of intervening transportation at various market locations. We use commodity fixed-price physical forwards and derivative contracts, including NYMEX-based futures and over-the-counter swaps, to minimize earnings volatility related to natural gas, NGL and condensate price fluctuations.

We reduce our gross processing spread exposure through a combination of physical and financial hedges. We utilize a portion of our percent-of-proceeds equity natural gas as an offset, or natural hedge, to an equivalent portion of our

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keep-whole shrink requirements. This has the effect of converting our gross processing spread risk to NGL commodity price risk, and we then use financial instruments to hedge the sale of NGLs.

The following tables set forth our Natural Gas Gathering and Processing segment's hedging information for the remainder of 2008 and for the year ending December 31, 2009.

	Three Months Ending December 31, 2008		
	Volumes Hedged	**Average Price**	**Percentage Hedged**
NGLs *(Bbl/d)* (a)	8,496	$ 1.30 / gallon	64%
Condensate *(Bbl/d)* (a)	773	$ 2.14 / gallon	53%
Total liquid sales *(Bbl/d)*	9,269	$ 1.37 / gallon	63%
Natural gas *(MMBtu/d)* (a)	5,000	$ 9.61 / MMBtu	56%

(a) - Hedged with fixed-price swaps.

	Year Ending December 31, 2009		
	Volumes Hedged	**Average Price**	**Percentage Hedged**
NGLs *(Bbl/d)* (a)	2,185	$2.08 / gallon	19%
Condensate *(Bbl/d)* (a)	666	$3.23 / gallon	30%
Total liquid sales *(Bbl/d)*	2,851	$2.35 / gallon	21%

(a) - Hedged with fixed-price swaps.

Our commodity price risk is estimated as a hypothetical change in the price of NGLs, crude oil and natural gas at September 30, 2008, excluding the effects of hedging and assuming normal operating conditions. Our condensate sales are based on the price of crude oil. We estimate the following:

- a $0.01 per gallon increase in the composite price of NGLs would increase annual net margin by approximately $1.5 million,
- a $1.00 per barrel increase in the price of crude oil would increase annual net margin by approximately $0.9 million, and
- a $0.10 per MMBtu increase in the price of natural gas would increase annual net margin by approximately $0.4 million.

The above estimates of commodity price risk do not include any effects on demand for our services that might be caused by, or arise in conjunction with, price changes. For example, a change in the gross processing spread may cause a change in the amount of ethane extracted from the natural gas stream, impacting gathering and processing margins, NGL exchange revenues, natural gas deliveries, and NGL volumes shipped and fractionated.

In our Natural Gas Liquids Gathering and Fractionation segment, we are exposed to commodity price risk primarily as a result of NGLs in storage, the relative values of the various NGL products to each other, the relative value of NGLs to natural gas and the relative value of NGL purchases at one location and sales at another location, known as basis risk. We have not entered into any hedges with respect to our NGL marketing activities.

In our Natural Gas Pipelines segment, we are exposed to commodity price risk because our intrastate and interstate natural gas pipelines collect natural gas from our customers for operations or as part of our fee for services provided. When the amount of natural gas consumed in operations by these pipelines differs from the amount provided by our customers, our pipelines must buy or sell natural gas, or store or use natural gas from inventory, which exposes us to commodity price risk. At September 30, 2008, there were no hedges in place with respect to natural gas price risk from our intrastate and interstate pipeline operations.

See Note D of the Notes to Consolidated Financial Statements in this Quarterly Report on Form 10-Q for more information on our hedging activities.

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COUNTERPARTY CREDIT RISK

We assess the credit worthiness of our counterparties on an on-going basis and require security, including prepayments and other forms of cash collateral, when appropriate.

ITEM 4. CONTROLS AND PROCEDURES

Quarterly Evaluation of Disclosure Controls and Procedures - As of the end of the period covered by this report, the Chief Executive Officer (Principal Executive Officer) and the Chief Financial Officer (Principal Financial Officer) of ONEOK Partners GP, our general partner, evaluated the effectiveness of our disclosure controls and procedures as defined in Rules 13a-15(e) and 15d-15(e) of the Exchange Act. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is accumulated and communicated to management of ONEOK Partners GP, including the officers of ONEOK Partners GP who are the equivalent of our principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure. Based on their evaluation, they concluded that as of September 30, 2008, our disclosure controls and procedures were effective in ensuring that the information required to be disclosed by us in the reports we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms.

Changes in Internal Control Over Financial Reporting - We have made no changes in our internal control over financial reporting (as defined in Rule 13a-15(f) and 15d-15(f) under the Exchange Act) during the third quarter ended September 30, 2008, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II - OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Additional information about our legal proceedings is included under Part I, Item 3, Legal Proceedings, in our Annual Report on Form 10-K for the year ended December 31, 2007.

Mont Belvieu Emissions, Texas Commission on Environmental Quality - We are in discussions with Texas Commission on Environmental Quality (TCEQ) staff regarding air emissions from a heat exchanger at our Mont Belvieu fractionator, which may have exceeded the emissions allowed under our air permit. We discovered the emissions in May 2008. The TCEQ has not issued a notice of enforcement relating to the emissions under this permit. Although no assurances can be given, we do not believe that any penalties associated with any alleged violations will have a material adverse effect on our financial position, results of operations, or net cash flows.

ITEM 1A. RISK FACTORS

Our investors should consider the risks set forth in Part I, Item 1A, Risk Factors of our Annual Report on Form 10-K for the year ended December 31, 2007, that could affect us and our business. These risk factors have not materially changed, except as set forth below. Although we have tried to discuss key factors, our investors need to be aware that other risks may prove to be important in the future. New risks may emerge at any time and we cannot predict such risks or estimate the extent to which they may affect our financial performance. Investors should carefully consider the discussion of risks and the other information included or incorporated by reference in this Quarterly Report on Form 10-Q, including “Forward-Looking Statements,” which are included in Part I, Item 2, Management’s Discussion and Analysis of Financial Condition and Results of Operations.

RISK FACTORS INHERENT IN OUR BUSINESS

We are subject to physical and financial risks associated with climate change.

There is a growing belief that emissions of greenhouse gases may be linked to global climate change. Climate change creates physical and financial risk. Our customers’ energy needs vary with weather conditions, primarily temperature and humidity. For residential customers, heating and cooling represent their largest energy use. To the extent weather conditions are affected by climate change, customers’ energy use could increase or decrease depending on the duration and magnitude of the changes. Increased energy use due to weather changes may require us to invest in more pipeline and other infrastructure to serve increased demand. A decrease in energy use due to weather changes may affect our financial condition, through decreased revenues. Extreme weather conditions in general require more system backup, adding to costs, and can contribute

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to increased system stresses, including service interruptions. Weather conditions outside of our service territory could also have an impact on our revenues. Severe weather impacts our service territories primarily through hurricanes, thunderstorms, tornadoes and snow or ice storms. To the extent the frequency of extreme weather events increases, this could increase our cost of providing service. We may not recover all costs related to mitigating these physical risks. To the extent financial markets view climate change and emissions of greenhouse gases as a financial risk, this could negatively affect our ability to access capital markets or cause us to receive less favorable terms and conditions in future financings.

We may be subject to legislative and regulatory responses to climate change, with which compliance could be difficult and costly.

Legislative and regulatory responses related to climate change create financial risk. Increased public awareness and concern may result in more state, regional and/or federal requirements to reduce or mitigate the emission of greenhouse gases. Numerous states have announced or adopted programs to stabilize and reduce greenhouse gases and federal legislation has been introduced in both houses of the United States Congress. Our pipeline and gas processing facilities will potentially be subject to regulation under climate change policies introduced at either the state or federal level within the next few years. We may not recover all costs related to complying with climate change regulatory requirements imposed on us. If our regulators do not allow us to recover all or a part of the cost of capital investment or operating and maintenance costs incurred to comply with the mandates, it could have a material adverse effect on our results of operations.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

Not Applicable.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

Not Applicable.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

Not Applicable.

ITEM 5. OTHER INFORMATION

Not Applicable.

ITEM 6. EXHIBITS

The following exhibits are filed as part of this Quarterly Report on Form 10-Q:

Exhibit No.	Exhibit Description
31.1	Certification of John W. Gibson pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Curtis L. Dinan pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of John W. Gibson pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished only pursuant to Rule 13a-14(b)).
32.2	Certification of Curtis L. Dinan pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished only pursuant to Rule 13a-14(b)).

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SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

ONEOK PARTNERS, L.P.
By: ONEOK Partners GP, L.L.C., its General Partner

Date: November 6, 2008

By: /s/ Curtis L. Dinan
Curtis L. Dinan
Executive Vice President,
Chief Financial Officer and Treasurer
(Signing on behalf of the Registrant
and as Principal Financial Officer)

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Section 2: EX-31.1 (SECTION 302 CERTIFICATION OF JOHN W. GIBSON)

Exhibit 31.1

Certification

I, John W. Gibson, certify that:

I have reviewed this quarterly report on Form 10-Q of ONEOK Partners, L.P.;

Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

The registrant’s other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

The registrant’s other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and
b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: November 6, 2008

/s/ John W. Gibson

Chief Executive Officer

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Section 3: EX-31.2 (SECTION 302 CERTIFICATION OF CURTIS L. DINAN)

Exhibit 31.2

Certification

I, Curtis L. Dinan, certify that:

I have reviewed this quarterly report on Form 10-Q of ONEOK Partners, L.P.;

Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 6, 2008

/s/ Curtis L. Dinan
Chief Financial Officer

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Section 4: EX-32.1 (SECTION 906 CERTIFICATION OF JOHN W. GIBSON)

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report on Form 10-Q of ONEOK Partners, L.P. (the "Company") for the period ending September 30, 2008 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, John W. Gibson, Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) the Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ John W. Gibson
John W. Gibson
Chief Executive Officer

November 6, 2008

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to ONEOK Partners, L.P. and will be retained by ONEOK Partners, L.P. and furnished to the Securities and Exchange Commission or its staff upon request.
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Section 5: EX-32.2 (SECTION 906 CERTIFICATION OF CURTIS L. DINAN)

Exhibit 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report on Form 10-Q of ONEOK Partners, L.P. (the "Company") for the period ending September 30, 2008 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Curtis L. Dinan, Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) the Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Curtis L. Dinan
Curtis L. Dinan
Chief Financial Officer

November 6, 2008

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to ONEOK Partners, L.P. and will be retained by ONEOK Partners, L.P. and furnished to the Securities and Exchange Commission or its staff upon request.
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OKS 10-K 12/31/2007

Section 1: 10-K (FORM 10-K)

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

X ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2007.
OR
__ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from _____ to _____.

Commission file number **1-12202**

ONEOK PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**93-1120873** (I.R.S. Employer Identification No.)
100 West Fifth Street, Tulsa, OK (Address of principal executive offices)	**74103-2498** (Zip Code)

Registrant's telephone number, including area code **(918) 588-7000**

Securities registered pursuant to Section 12(b) of the Act:

Common units (Title of Each Class)	**New York Stock Exchange** (Name of Each Exchange on which Registered)

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes X No __.

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes __ No X.

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days. Yes X No __

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Registration S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. X

Indicate by checkmark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one)
Large accelerated filer X Accelerated filer __ Non-accelerated filer __

Indicate by checkmark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act).
Yes __ No X.

Aggregate market value of the common units held by non-affiliates based on the closing trade price on June 30, 2007, was $3.2 billion.

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Class	Outstanding at February 20, 2008
Common units	46,397,214 units
Class B units	36,494,126 units

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ONEOK PARTNERS, L.P.
2007 ANNUAL REPORT ON FORM 10-K

In this Annual Report on Form 10-K, references to "we," "our," "us" or the "Partnership" refer to ONEOK Partners, L.P. and its subsidiary, ONEOK Partners Intermediate Limited Partnership and its subsidiaries, formerly known as Northern Border Partners, L.P. and Northern Border Intermediate Limited Partnership, respectively.

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GLOSSARY

The abbreviations, acronyms, industry terminology and certain other terms used in this Annual Report on Form 10-K are defined as follows:

AFUDC	Allowance for funds used during construction
APB Opinion	Accounting Principles Board Opinion
ARB	Accounting Research Bulletin
Bbl	Barrels, 1 barrel is equivalent to 42 United States gallons
Bbl/d	Barrels per day
BBtu/d	Billion British thermal units per day
Bcf	Billion cubic feet
Bcf/d	Billion cubic feet per day
Bighorn Gas Gathering	Bighorn Gas Gathering, L.L.C.
Black Mesa	Black Mesa Pipeline, Inc.
Btu	British thermal units, a measure of the amount of heat required to raise the temperature of one pound of water one degree Fahrenheit
Bushton Plant	Bushton Gas Processing Plant
EITF	Emerging Issues Task Force
EPA	United States Environmental Protection Agency
Exchange Act	Securities Exchange Act of 1934, as amended
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FIN	FASB Interpretation
Fort Union Gas Gathering	Fort Union Gas Gathering, L.L.C.
GAAP	Generally Accepted Accounting Principles in the United States
Guardian Pipeline	Guardian Pipeline, L.L.C.
Heartland	Heartland Pipeline Company
Intermediate Partnership	ONEOK Partners Intermediate Limited Partnership, formerly known as Northern Border Intermediate Limited Partnership, a wholly owned subsidiary of ONEOK Partners, L.P.
IRS	Internal Revenue Service
KCC	Kansas Corporation Commission
KDHE	Kansas Department of Health and Environment
LIBOR	London Interbank Offered Rate
Lost Creek Gathering Company	Lost Creek Gathering Company, L.L.C
MBbl	Thousand barrels
MBbl/d	Thousand barrels per day
Midwestern Gas Transmission	Midwestern Gas Transmission Company
MMBtu	Million British thermal units
MMBtu/d	Million British thermal units per day
MMcf	Million cubic feet
MMcf/d	Million cubic feet per day
Moody’s	Moody’s Investors Service, Inc.
NBP Services	NBP Services, LLC, a subsidiary of ONEOK
NGL(s)	Natural gas liquid(s)
Northern Border Pipeline	Northern Border Pipeline Company
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
OBPI	ONEOK Bushton Processing Inc.
OCC	Oklahoma Corporation Commission
OkTex Pipeline	OkTex Pipeline Company, L.L.C.
ONEOK	ONEOK, Inc.
ONEOK NB	ONEOK NB Company, formerly known as Northwest Border Pipeline Company, a wholly owned subsidiary of ONEOK, Inc.
ONEOK Partners GP	ONEOK Partners GP, L.L.C., formerly known as Northern Plains Natural Gas Company, LLC, a wholly owned subsidiary of ONEOK, Inc. and our sole general partner
Overland Pass Pipeline Company	Overland Pass Pipeline Company LLC
Partnership Agreement	Third Amended and Restated Agreement of Limited Partnership of ONEOK Partners, L.P.

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POP	Percent of Proceeds
RRC	Texas Railroad Commission
S&P	Standard & Poor's Rating Group
SEC	Securities and Exchange Commission
Statement	Statement of Financial Accounting Standards
TC PipeLines	TC PipeLines Intermediate Limited Partnership, a subsidiary of TC PipeLines, LP
TransCanada	TransCanada Corporation
Viking Gas Transmission	Viking Gas Transmission Company

The statements in this Annual Report on Form 10-K that are not historical information, including statements concerning plans and objectives of management for future operations, economic performance or related assumptions, are forward-looking statements. Forward-looking statements may include words such as "anticipate," "estimate," "expect," "project," "intend," "plan," "believe," "should," "goal," "forecast" and other words and terms of similar meaning. Although we believe that our expectations regarding future events are based on reasonable assumptions, we can give no assurance that our goals will be achieved. Important factors that could cause actual results to differ materially from those in the forward-looking statements are described under Part I, Item 1A, Risk Factors, and Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operation—Forward-Looking Statements in this Annual Report on Form 10-K for the year ended December 31, 2007.

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PART I

ITEM 1. BUSINESS

GENERAL

ONEOK Partners, L.P. is a publicly traded Delaware limited partnership that was formed in 1993. Our common units are listed on the NYSE under the trading symbol "OKS." We own and manage natural gas gathering, processing, storage and interstate and intrastate pipeline assets and natural gas liquids gathering and distribution pipelines, storage and fractionators, connecting much of the natural gas and NGL supply in the Mid-Continent and Gulf Coast regions with key market centers in Conway, Kansas, Mont Belvieu, Texas, and Chicago, Illinois. We also own a 50 percent equity interest in a leading transporter of natural gas imported from Canada into the United States.

DESCRIPTION OF BUSINESS SEGMENTS

In July 2007, we announced a series of organizational changes that led to the realignment of our previous business segments. Our financial results are now reported in these four segments: (i) Natural Gas Gathering and Processing, which remains unchanged, (ii) Natural Gas Pipelines, which is comprised of our former interstate natural gas pipelines segment and the natural gas assets of our former pipelines and storage segment, (iii) Natural Gas Liquids Gathering and Fractionation, which remains unchanged, and (iv) Natural Gas Liquids Pipelines, which is comprised of the natural gas liquids assets of our former pipelines and storage segment. Prior periods have been restated to reflect these segment changes. The change reflects the increasing scale of the natural gas liquids business, which has grown significantly since 2006. Our natural gas liquids business is expanding as we integrate the assets acquired in October 2007 from a subsidiary of Kinder Morgan Energy Partners, L.P. (Kinder Morgan) into our Natural Gas Liquids Pipelines segment and complete our other internal growth projects.

Our operations are divided into these strategic business segments based on similarities in economic characteristics, products and services, types of customers, methods of distribution and regulatory environment, as follows:

- our Natural Gas Gathering and Processing segment primarily gathers and processes raw natural gas;
- our Natural Gas Pipelines segment primarily operates regulated interstate and intrastate natural gas transmission pipelines and natural gas storage facilities;
- our Natural Gas Liquids Gathering and Fractionation segment primarily gathers, treats and fractionates NGLs and stores and markets NGL products; and
- our Natural Gas Liquids Pipelines segment primarily operates our FERC-regulated interstate natural gas liquids gathering and distribution pipelines.

For financial and statistical information regarding our business segments, see Item 7, Management’s Discussion and Analysis of Financial Condition and Results of Operation. See Note J of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for a discussion of sales to unaffiliated customers, operating income and total assets by business segment.

Partnership Structure

We are managed under the direction of the Board of Directors of our sole general partner, ONEOK Partners GP, which consists of six members. Three of our Board members qualify as independent under the listing standards of the NYSE and also serve as the Audit Committee of ONEOK Partners GP. ONEOK Partners GP is a wholly owned subsidiary of ONEOK. ONEOK owns a 45.7 percent aggregate equity interest in us.

Business Strategy

Our primary business objectives are to generate cash flow sufficient to pay quarterly cash distributions to our unitholders and to increase our quarterly cash distributions over time. Our ability to maintain and grow our distributions to unitholders depends on the growth of our existing businesses and strategic acquisitions. We focus on safe, environmentally sound and compliant operations for our employees, contractors, customers and the public.

Our strategy is to expand and acquire assets in the United States related to gathering, processing, fractionating, storing and marketing natural gas and NGLs that will utilize our core competencies, minimize commodity price risk and provide long-

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term, sustainable and stable cash flows. We finance our acquisitions and capital expenditures with a mix of operating cash flows, debt and equity.

In April 2006, we acquired certain companies comprising ONEOK's former gathering and processing, natural gas liquids, and pipeline and storage segments, collectively referred to as the "ONEOK Energy Assets" from ONEOK, the parent company of our general partner, in a series of transactions, collectively referred to as the "ONEOK Transactions," which are described in Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operation under "Significant Acquisitions and Divestitures." These assets complemented our core competencies related to energy services and diversified our portfolio of assets. The assets we acquired from ONEOK enabled us to enter into energy-related businesses in the well-established Mid-Continent region and key natural gas liquids markets in Kansas and Texas. In addition, our expanded asset portfolio positions us for future organic growth projects, which we believe currently offer the most attractive growth opportunities for us.

SIGNIFICANT DEVELOPMENTS IN 2007 AND EARLY 2008

In February 2008, we announced plans to construct a 78-mile natural gas liquids gathering pipeline to connect two natural gas processing plants in the Woodford Shale area in southeast Oklahoma at a cost of approximately $25 million, excluding AFUDC. The project is currently scheduled for completion in the second quarter of 2008. These two plants are expected to produce approximately 25 MBbl/d of unfractionated NGLs. Until the Arbuckle Pipeline project is completed, the natural gas liquids production will be transported by our existing Mid-Continent natural gas liquids pipelines. Upon completion of the Arbuckle Pipeline project, the Woodford Shale natural gas liquids production is expected to be transported to our Mont Belvieu, Texas, fractionation facility.

In October 2007, we completed the acquisition of an interstate natural gas liquids and refined petroleum products pipeline system and related assets from a subsidiary of Kinder Morgan for approximately $300 million, before working capital adjustments. The system extends from Bushton and Conway, Kansas, to Chicago, Illinois, and transports, stores and delivers a full range of NGL and refined products. The FERC-regulated system spans 1,627 miles and has a capacity to transport up to 134 MBbl/d. The transaction includes approximately 978 MBbl of owned storage capacity, eight NGL terminals and a 50 percent ownership of Heartland.

In September 2007, we completed an underwritten public debt offering of $600 million to finance the assets acquired from Kinder Morgan and to repay outstanding debt under the 2007 Partnership Credit Agreement, which was incurred to fund our internal growth capital projects.

During 2007, we began construction on the Overland Pass Pipeline Company joint-venture project with a subsidiary of The Williams Companies, Inc. (Williams). Overland Pass Pipeline Company is building a 760-mile natural gas liquids pipeline from Opal, Wyoming, to the Mid-Continent natural gas liquids market center in Conway, Kansas. The pipeline is designed to transport approximately 110 MBbl/d of unfractionated NGLs, which can be increased to approximately 150 MBbl/d with additional pump facilities. This project has received the required approvals of various state and federal regulatory authorities, and we are constructing the pipeline with start-up currently scheduled for the second quarter of 2008.

In March 2007, we announced that Overland Pass Pipeline Company also plans to construct a 150-mile lateral pipeline with capacity to transport as much as 100 MBbl/d of unfractionated NGLs from the Piceance Basin in Colorado to the Overland Pass Pipeline. Williams announced that it intends to construct a new natural gas processing plant in the Piceance Basin and will dedicate its NGL production from that plant and an existing plant to be transported by the lateral pipeline. This project requires the approval of various state and federal regulatory authorities. Assuming Overland Pass Pipeline Company obtains the required state and federal regulatory approvals, construction of this lateral pipeline is currently expected to begin in late 2008 and be completed during the second quarter of 2009.

In March 2007, we announced plans to build the 440-mile Arbuckle Pipeline, a natural gas liquids pipeline from southern Oklahoma through northern Texas and continuing on to the Texas Gulf Coast. The Arbuckle Pipeline will have the capacity to transport 160 MBbl/d of unfractionated natural gas liquids and will connect our existing Mid-Continent infrastructure with our fractionation facility in Mont Belvieu, Texas, and other Gulf Coast region fractionators. Construction of the pipeline will require permits from various federal, state and local regulatory bodies. Construction is currently expected to begin in mid-2008 and will be completed by early 2009.

In March 2007, we announced the expansion of our Grasslands natural gas processing facility in North Dakota. The Grasslands facility is our largest natural gas processing plant in the Williston Basin. The expansion increases processing capacity to approximately 100 MMcf/d from its current capacity of 63 MMcf/d and increases fractionation capacity to

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approximately 12 MBbl/d from 8 MBbl/d. The expansion project is expected to come on-line in phases, with the final phase currently expected to be on-line in the third quarter of 2008.

In January 2007, Fort Union Gas Gathering announced that it will double its existing gathering pipeline capacity by adding 148 miles of new gathering lines and approximately 649 MMcf/d of additional capacity in the Powder River basin of Wyoming. The expansion will occur in two phases. Phase 1 was placed in service during the fourth quarter of 2007. Phase 2 is currently expected to be in service during the second quarter of 2008. We own approximately 37 percent of Fort Union Gas Gathering.

NARRATIVE DESCRIPTION OF BUSINESS

Natural Gas Gathering and Processing

Business Strategy - We focus on safe, environmentally sound and compliant operations for our employees, contractors, customers and the public. We pursue growth through additional well connections, system expansions and strategic acquisitions. We seek to restructure expiring contracts to mitigate commodity exposure. We also seek to provide reliable, efficient and consistent operations through optimization of our natural gas gathering and processing operations while managing costs.

Segment Description - Our former gathering and processing segment is now called our Natural Gas Gathering and Processing segment. As part of the ONEOK Transactions described in Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operation under "Significant Acquisitions and Divestitures," we acquired all of ONEOK's natural gas gathering and processing assets and combined them with our legacy gathering and processing segment assets in April 2006.

Our operations include gathering of natural gas production from oil and natural gas wells. We gather raw natural gas in the Mid-Continent region, which includes the Anadarko Basin of Oklahoma and the Hugoton and Central Kansas Uplift Basins of Kansas. We also gather raw natural gas in three producing basins in the Rocky Mountain region: (i) the Williston Basin, which spans portions of Montana, North Dakota and the Canadian province of Saskatchewan, (ii) the Powder River Basin of Wyoming and (iii) the Wind River Basin of Wyoming.

Through gathering systems, raw natural gas volumes are aggregated for removal of water vapor, solids and other contaminants and to extract NGLs in order to provide marketable natural gas, commonly referred to as residue gas. When the liquids are separated from the raw natural gas at the processing plants, the liquids are in the form of a mixed, unfractionated NGL stream. This unfractionated NGL stream is generally shipped to fractionators, where by applying heat and pressure, the unfractionated NGL stream is separated into marketable purity products, such as ethane/propane mix, propane, iso-butane, normal butane and natural gasoline (collectively, NGL products). These NGL products can then be stored, transported and marketed to a diverse customer base.

Our Natural Gas Gathering and Processing segment gathers and processes raw natural gas. We generally gather and process gas under the following types of contracts.

- Percent of Proceeds (POP) - Under a POP contract, we retain a percentage of the NGLs and/or a percentage of the residue gas as payment for gathering, compressing and processing the producer's raw natural gas. The producer may take its share of the NGLs and residue gas in kind or receive its share of proceeds from our sale of the commodities. POP contracts expose us to both natural gas and NGL commodity price risk, but economically align us with the producer because we both benefit from higher commodity prices. There are a variety of factors that directly affect our POP margins, including:
    - the percentages of products retained that represent our equity NGL, condensate and residue gas sales volumes,
    - transportation and fractionation costs incurred on the NGLs, and
    - the natural gas, crude oil and NGL prices received for our retained products.
- Fee - Under a fee contract, we are paid a fee for the services provided on a basis such as Btus gathered, compressed and/or processed. The wellhead volume and fees received for the services provided are the main components of the margin for this type of contract. The producer may take its NGLs and residue gas in kind or receive its proceeds from our sale of the commodities. This type of contract primarily exposes us to volumetric risk with minimal commodity price risk, as a result of fuel costs and the value of the retained fuel. Our POP and keep-whole contracts also typically include fee provisions.
- Keep-Whole - Under a keep-whole processing contract, we extract NGLs from the raw natural gas and return to the producer volumes of residue gas containing the same amount of Btus as the raw natural gas that was delivered to us.

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We retain the NGLs as our fee for processing. Accordingly, we must purchase and return to the producer sufficient volumes of residue gas to replace the Btus that were removed as NGLs through the gathering and processing operation, commonly referred to as "shrink." Under index-based purchase agreements, we purchase raw natural gas at the wellhead to replace the natural gas that we consume in processing, and we typically bear the full cost of the plant fuel and shrink, with the excess residue gas being sold monthly at index-based prices. By using this contract type, the producer is kept whole on a Btu basis. This type of contract exposes us to the keep-whole spread, or gross processing spread, which is the relative difference in the economic value between NGLs and natural gas on a Btu basis. The main factors that affect our keep-whole margins include:

- shrink,
- plant fuel consumed,
- transportation and fractionation costs incurred on the NGLs,
- gross processing spread, and
- the natural gas, crude oil and NGL prices received for products sold.

Excluding any gain on sale of assets, operating income from our Natural Gas Gathering and Processing segment was 42 percent, 46 percent and 17 percent of our consolidated operating income in 2007, 2006 and 2005, respectively. Operating revenue of this segment is derived primarily from POP and fee contracts. We use derivative instruments to mitigate our sensitivity to fluctuations in the price of natural gas, condensate and NGLs. Our Natural Gas Gathering and Processing segment had no single external customer from which it received 10 percent or more of consolidated revenues. Intersegment sales accounted for 35 percent of our Natural Gas Gathering and Processing segment's revenues in 2007 and 2006. Our Natural Gas Gathering and Processing segment had no intersegment sales in 2005. A portion of our revenues are from ONEOK and its affiliates.

Market Conditions and Seasonality - Supply - Natural gas supply is affected by rig availability, operating capability and producer drilling activity, which is sensitive to commodity prices, geological success, available capital and regulatory control. Relatively high natural gas and crude oil prices, as well as favorable long-term projections of U.S. demand, continued to drive increased drilling in 2007 in the Mid-Continent and Rocky Mountain regions, which are our primary supply regions.

In the Mid-Continent region, the gathering and processing assets we acquired in the Anadarko Basin of Oklahoma and the Hugoton and Central Kansas Uplift Basins of Kansas are well established. However, we anticipate continuing volumetric declines in certain fields that supply our gathering and processing operations. Additionally, there is excess processing capacity, particularly in the Hugoton production region, which includes the Bushton Plant. Partly as a result of the Bushton Plant's inability to recover certain NGLs, such as ethane, the plant was at an economic disadvantage to the region's other cryogenic plants, and it was temporarily idled on January 1, 2007. See discussion on page 26.

In the Williston Basin, we connected more wells in 2007 than in prior years as a result of increased drilling activity. Transportation and refining capacity constraints for crude oil continue to only moderately impact natural gas production in the Williston Basin. Further development of the Big George coals, located in the center of the Powder River Basin, resulted in greater volumes during 2007, compared with 2006, for our wholly owned assets and joint-venture interests in Bighorn Gas Gathering and Fort Union Gas Gathering.

Demand - Demand for gathering and processing services is typically aligned with the supply of natural gas, which generally flows from a producing area at a relatively steady but gradually declining pace over time unless new reserves are added. Our plant operations can be adjusted to respond to market conditions, such as demand for ethane. By changing, within limits, the temperature and pressure at which raw natural gas is processed, we can produce more of the specific commodity that has the most favorable price or price spread.

Commodity Prices - Crude oil, natural gas and NGL prices are volatile due to market conditions. Storage injection and withdrawal rates, as well as available storage capacity, can also have an impact on commodity prices. We are exposed to market risk associated with adverse changes in commodity prices. Our primary exposures arise from the sale of natural gas, NGLs and condensate with respect to our processing contracts. To a lesser extent, we are exposed to the relative price differential between NGLs and natural gas, the risk of price fluctuations and the cost of intervening transportation at various market locations, and the demand for our products by the petrochemical industry and others.

Seasonality - Some of this segment's products are subject to weather-related seasonal demand. Cold temperatures typically increase demand for natural gas and propane, which are used to heat homes and businesses. Warm temperatures typically drive demand for natural gas used for gas-fired electric generation used to cool residential and commercial properties. Demand for iso-butane and natural gasoline, which are primarily used by the refining industry as blending stocks for motor

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fuel, may also be subject to some variability when automotive travel is higher. During periods of peak demand for a certain commodity, prices for that product typically increase, which influences processing decisions.

Competition - The gathering and processing business remains relatively fragmented despite significant consolidation in the industry. We compete for natural gas supplies with major integrated exploration and production companies, pipeline companies and their affiliated marketing companies, national and local natural gas gatherers and processors, and marketers in the Mid-Continent and Rocky Mountain regions.

Due to the unprecedented strength of the energy commodity market over the past two years, gathering and processing rates have become increasingly competitive. As a result, we may not be successful in obtaining new natural gas supplies to offset declines and may lose some existing supplies to competitors. We are responding to these industry conditions by making capital investments to improve plant processing flexibility and reduce operating costs, evaluating consolidation opportunities to maximize earnings, selling assets in non-core operating areas and renegotiating unprofitable contracts. Contracts covering approximately 84 percent of our volumes under keep-whole contracts contain language that effectively converts these contracts into fee contracts when the keep-whole spread is negative.

Government Regulation - The FERC has traditionally maintained that a processing plant is not a facility for the transportation or sale for resale of natural gas in interstate commerce and, therefore, is not subject to jurisdiction under the Natural Gas Act. Although the FERC has made no specific declaration as to the jurisdictional status of our natural gas processing operations or facilities, our natural gas processing plants are primarily involved in removing NGLs and, therefore, we believe, are exempt from FERC jurisdiction. The Natural Gas Act also exempts natural gas gathering facilities from the jurisdiction of the FERC. Interstate transmission facilities remain subject to FERC jurisdiction. The FERC has historically distinguished between these two types of facilities, either interstate or intrastate, on a fact-specific basis. We believe our gathering facilities and operations meet the criteria used by the FERC for non-jurisdictional gathering facility status. We can transport residue gas from our plants to interstate pipelines in accordance with Section 311(a) of the Natural Gas Policy Act.

Oklahoma and Kansas also have statutes regulating, to various degrees, the gathering of natural gas in those states. In each state, regulation is applied on a case-by-case basis if a complaint is filed against the gatherer with the appropriate state regulatory agency.

Natural Gas Pipelines

Business Strategy - We focus on safe, environmentally sound and compliant operations for our employees, contractors, customers and the public. We seek to maintain a competitive cost structure and increase throughput and growth of our existing natural gas pipelines and storage assets through extensions and expansions supported by long-term transportation and reservation contracts.

Segment Description - Our Natural Gas Pipelines segment is comprised of our previous interstate natural gas pipelines segment and the natural gas assets of our previous pipelines and storage segment. This segment primarily operates regulated natural gas transmission pipelines, natural gas storage facilities, and non-processable natural gas gathering facilities. We also provide interstate natural gas transportation and storage service in accordance with Section 311(a) of the Natural Gas Policy Act.

Our interstate natural gas pipeline assets transport natural gas through FERC-regulated interstate natural gas pipelines in Montana, North Dakota, South Dakota, Minnesota, Wisconsin, Illinois, Indiana, Kentucky, Tennessee, Oklahoma, Texas and New Mexico. Our interstate pipelines include Midwestern Gas Transmission, Guardian Pipeline, Viking Gas Transmission, OkTex Pipeline and a 50 percent interest in Northern Border Pipeline.

Our intrastate natural gas pipeline assets in Oklahoma have access to the major natural gas producing areas and transport natural gas throughout the state. We also have access to the major natural gas producing area in south central Kansas. In Texas, our intrastate natural gas pipelines are connected to the major natural gas producing areas in the Texas panhandle and the Permian Basin, and transport natural gas to the Waha Hub, where other pipelines may be accessed for transportation east to the Houston Ship Channel market, north into the Mid-Continent market and west to the California market.

We own or reserve storage capacity in underground natural gas storage facilities in Oklahoma, Kansas and Texas.

Our transportation contracts for our regulated natural gas activities are based upon rates stated in our tariffs. Tariffs specify the maximum rates customers can be charged, which can be discounted to meet competition if necessary, and the general terms and conditions for pipeline transportation service, which are established at FERC or appropriate state jurisdictional

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agency proceedings known as rate cases. In Texas and Kansas, natural gas storage service is a fee business that may be regulated by the state in which the facility operates and by the FERC for certain types of services. In Oklahoma, natural gas gathering and natural gas storage operations are not subject to rate regulation and have market-based rate authority from the FERC for certain types of services.

Our Natural Gas Pipelines segment's revenues are typically derived from fee services from the following types of contracts.

- Firm Service - Customers can reserve a fixed quantity of pipeline or storage capacity for the term of their contract. Under this type of contract, the customer pays a fixed fee for a specified quantity regardless of their actual usage. The customer then typically pays incremental fees, known as commodity charges, that are based upon the actual volume of natural gas they transport or store and/or we may retain a specified volume of natural gas in-kind for fuel. Under the firm service contract, the customer is generally guaranteed access to the capacity they reserve.
- Interruptible Service - Customers with interruptible service transportation and storage agreements may utilize available capacity after firm service requests are satisfied or on an as-available basis. Interruptible service customers are typically assessed fees, such as a commodity charge, based on their actual usage and/or we may retain a specified volume of natural gas in-kind for fuel. Under the interruptible service contract, the customer is not guaranteed use of our pipelines and storage facilities unless excess capacity is available.

Excluding any gain on sale of assets, operating income from our Natural Gas Pipelines segment was 25 percent, 31 percent and 83 percent of our consolidated operating income in 2007, 2006 and 2005, respectively. Our Natural Gas Pipelines segment had no single external customer from which it received 10 percent or more of consolidated revenues. Intersegment sales accounted for less than 1 percent of our Natural Gas Pipelines segment's revenues in 2007 and 2006, respectively. Our Natural Gas Pipelines segment had no intersegment sales in 2005. A portion of our revenue is derived from services provided to ONEOK and its affiliates.

Market Conditions and Seasonality - Supply - The supply of natural gas for Viking Gas Transmission and Northern Border Pipeline originates in Canada. Significant factors that can impact the supply of Canadian natural gas transported by our pipelines are the Canadian natural gas available for export, Canadian storage capacity and demand for Canadian natural gas in other U.S. consumer markets. The supply of natural gas to our Guardian, Midwestern and Mid-Continent pipelines and storage assets currently depends on the pace of natural gas drilling activity by producers and the decline rate of existing production in the major natural gas production areas in the Mid-Continent region, including the Anadarko Basin, Hugoton Basin, Central Kansas Uplift Basin and Permian Basin. United States natural gas drilling rig counts increased in 2007 compared with 2006. The natural gas supply from the Gulf Coast also supports our Mid-Continent and upper Midwest pipeline facilities. This supply source is primarily dependent on offshore Gulf Coast production and, to a lesser degree, imports of liquefied natural gas.

Demand - Demand for pipeline transportation service and natural gas storage is directly related to demand for natural gas in the markets that the natural gas pipelines and storage facilities serve, and is affected by weather, the economy, and natural gas and NGL price volatility. The effect of weather on our natural gas pipelines operations is discussed below under "Seasonality." The strength of the economy directly impacts manufacturing and industrial companies that rely on natural gas. Commodity price volatility can influence customers' decisions related to the production of natural gas versus NGLs and natural gas storage injection and withdrawal activity.

Commodity Prices - We are exposed to market risk when existing contracts expire and are subject to renegotiation with customers that have competitive alternatives and analyze the market price spread or basis differential between receipt and delivery points along the pipeline to determine their expected gross margin. The anticipated margin and its variability are important determinants of the transportation rate customers are willing to pay. Natural gas storage revenue is impacted by the differential between forward pricing of natural gas physical contracts and the price of natural gas on the spot market. Our fuel costs and the value of the retained fuel in-kind are also impacted by adverse changes in the commodity price of natural gas.

Seasonality - Demand for natural gas is seasonal. Weather conditions throughout the United States can significantly impact regional natural gas supply and demand. High temperatures can increase demand for gas-fired electric generation to cool residential and commercial properties. Low precipitation levels can impact the demand for natural gas that is used to fuel irrigation activity in the Mid-Continent region. Cold temperatures can lead to greater demand for our transportation services due to increased demand for natural gas.

To the extent that pipeline capacity is contracted under firm service transportation agreements, revenue, which is generated primarily from demand charges, is not significantly impacted by seasonal throughput variations. However, when transportation agreements expire, seasonal demand can impact re-contracting of firm service transportation capacity.

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Natural gas storage is necessary to balance the relatively steady natural gas supply with the seasonal demand of residential, commercial and electric power generation users. The majority of our storage capacity is contracted under term agreements. A small portion of our storage capacity is retained for operational purposes and seasonal market activity.

Competition - Our Natural Gas Pipelines segment competes with other pipeline companies and other storage facilities for natural gas. Competition among pipelines and natural gas storage facilities is based primarily on fees for service and proximity to natural gas supply areas and markets. Competition for natural gas transportation services continues to increase as the FERC and state regulatory bodies continue to encourage more competition in the natural gas markets.

Government Regulation - Our interstate natural gas pipelines are regulated under the Natural Gas Act and Natural Gas Policy Act, which give the FERC jurisdiction to regulate virtually all aspects of this business segment, such as transportation of natural gas, rates and charges for services, construction of new facilities, depreciation and amortization policies, acquisition and disposition of facilities, and initiation and discontinuation of services.

Likewise, our intrastate natural gas pipelines in Oklahoma, Kansas and Texas are regulated by the OCC, KCC and RRC, respectively. While we have flexibility in establishing natural gas transportation rates with customers, there is a maximum rate that we can charge our customers in Oklahoma and Kansas.

Natural Gas Liquids Gathering and Fractionation

Business Strategy - We focus on safe, environmentally sound and compliant operations for our employees, contractors, customers and the public. We seek to maximize our value by increasing facility utilization and efficiently managing the operating costs of our natural gas liquids assets, which consist of facilities that gather, fractionate and treat NGLs and store NGL purity products in the Mid-Continent and Gulf Coast regions.

Segment Description - Our former natural gas liquids segment is now called our Natural Gas Liquids Gathering and Fractionation segment. As part of the ONEOK Transactions described in Item 7, Management’s Discussion and Analysis of Financial Condition and Results of Operation under "Significant Acquisitions and Divestitures," in April 2006, we acquired all of ONEOK’s natural gas liquids assets and created a new segment that consisted solely of these newly acquired natural gas liquids assets.

Our Natural Gas Liquids Gathering and Fractionation segment primarily gathers, treats and fractionates NGLs produced by natural gas processing plants located in Oklahoma, Kansas, the Texas panhandle and the Texas Gulf Coast, and stores and markets NGL products. We connect the NGL production basins in Oklahoma, Kansas and the Texas panhandle with the key natural gas liquids market centers in Conway, Kansas, and Mont Belvieu, Texas.

Most natural gas produced at the wellhead contains a mixture of NGL components such as ethane, propane, iso-butane, normal butane and natural gasoline. Natural gas processing plants remove the NGLs from the natural gas stream to realize the higher economic value of the NGLs and to meet natural gas pipeline quality specifications, which limit NGLs in the natural gas stream by liquid and Btu content. The NGLs that are separated from the natural gas stream at the natural gas processing plants remain in a mixed, unfractionated form until they are gathered, primarily by pipeline, and delivered to our fractionators. A fractionator, by applying heat and pressure, separates the unfractionated NGL stream into marketable purity products, such as ethane/propane mix, propane, iso-butane, normal butane and natural gasoline (collectively, NGL products). These NGL products are then stored and/or distributed to our customers, such as petrochemical plants, heating fuel users and motor gasoline manufacturers.

Operating revenue of this segment is derived primarily from exchange services, optimization, isomerization and storage.

- Our exchange services business collects fees to gather, fractionate and treat unfractionated NGLs thereby converting them into NGL products that are stored and shipped to a market center or customer-designated location.
- Our optimization business utilizes our asset base, contract portfolio and market knowledge to capture locational and seasonal price spreads. We move NGL products between Conway, Kansas, and Mont Belvieu, Texas, in order to capture the locational price spreads between the two market centers. Our NGL storage facilities in the Mid-Continent and Gulf Coast regions are used to capture seasonal price variances.
- Our isomerization business captures the price spread when normal butane is converted into the more valuable iso-butane at an isomerization unit in Conway, Kansas. Iso-butane is used in the refining industry to upgrade the octane of motor gasoline.
- Our storage business collects fees to store NGLs in Conway, Kansas, and Mont Belvieu, Texas.

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Excluding any gain on sale of assets, operating income from our Natural Gas Liquids Gathering and Fractionation segment was 25 percent and 22 percent of our consolidated operating income in 2007 and 2006, respectively. We did not have a Natural Gas Liquids Gathering and Fractionation segment prior to 2006. Our Natural Gas Liquids Gathering and Fractionation segment had no single external customer from which it received 10 percent or more of consolidated revenues. Intersegment sales accounted for less than one percent of our Natural Gas Liquids Gathering and Fractionation segment's revenues in 2007 and 2006, respectively.

Market Conditions and Seasonality - Supply - Supply for our Natural Gas Liquids Gathering and Fractionation segment depends on the pace of crude oil and natural gas drilling activity by producers, the decline rate of existing production, and the liquids content of the natural gas that is produced and processed. Our Mont Belvieu fractionation operation receives NGLs from a variety of processors and pipelines located in the Gulf Coast, west and central Texas, and the Rocky Mountain regions.

Our NGL gathering pipelines are also affected by operational or market-driven changes that impact the output of natural gas processing plants to which they are connected. The differential between the composite price of NGL products and the price of natural gas, particularly the differential between the price of ethane and the price of natural gas, may influence processing plant output. Typically, the forward price of ethane compared with the forward price of natural gas provides minimal or no processing spread. However, when the physical transactions occur, the price of ethane to natural gas has historically provided a positive processing spread. During 2007, ethane values remained above those of natural gas on a relative price basis, which resulted in ethane recovery from processing plants that deliver to our natural gas liquids gathering pipelines.

Demand - Demand for NGLs and the ability of natural gas processors to successfully and economically sustain their operations impacts the volume of unfractionated NGLs produced by processing plants, thereby affecting the demand for natural gas liquids gathering and fractionation services. Natural gas and propane are subject to weather-related seasonal demand. Other products are affected by economic conditions and the demand associated with the various industries that utilize the commodity, such as iso-butane and natural gasoline, which are used by the refining industry as blending stocks for motor fuel, ethane, and an ethane/propane mix. This ethane/propane mix is used by the petrochemical industry to produce chemical products, such as plastic, rubber and synthetic fiber.

Commodity Prices - In recent years, crude oil, natural gas and NGL prices have been volatile due to market conditions. We are exposed to market risk associated with adverse changes in the price of NGLs, the basis differential between the Mid-Continent and Gulf Coast regions, and the relative price differential between natural gas, NGLs and individual NGL products, which impact our NGL purchases, sales, exchange and storage revenue. When natural gas prices are higher relative to NGL prices, NGL production may decline, which could negatively impact our exchange services revenue. When the basis differential between the Mid-Continent and Gulf Coast regions is narrow, optimization opportunity and margins may decline. NGL storage revenue may be impacted by price volatility and forward pricing of NGL physical contracts versus the price of NGLs on the spot market.

Seasonality - Some NGL products produced by our natural gas liquids facilities are subject to weather-related seasonal demand, such as propane, which is primarily used to heat residential properties during the winter heating season. Demand for iso-butane and natural gasoline, which are primarily used by the refining industry as blending stocks for motor fuel, may also be subject to some variability when automotive travel is higher.

Competition - We compete with other fractionators, storage providers and gatherers for natural gas liquids supplies in the Rocky Mountain, Mid-Continent and Gulf Coast regions. We are making capital investments to access new supplies, increase gathering and fractionation capacity, increase storage capabilities and reduce operating costs so that we may compete more effectively.

Government Regulations - Revenues generated by our pipelines in both Oklahoma and Kansas are not regulated by the FERC or those states' respective corporation commissions.

Natural Gas Liquids Pipelines

Business Strategy - We focus on safe, environmentally sound and compliant operations for our employees, contractors, customers and the public. We seek to increase throughput and continue to provide cost-effective transportation for NGLs between the Mid-Continent, the Gulf Coast and the Midwest markets near Chicago, Illinois. We pursue growth of our interstate natural gas liquids pipelines by making capital investments to expand our access to new supplies and increase our pipeline capacity.

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Segment Description - Our Natural Gas Liquids Pipelines segment is comprised of the natural gas liquids assets of our previous pipelines and storage segment, and our natural gas liquids and refined petroleum products pipeline systems and related assets acquired from Kinder Morgan in October 2007. This segment operates FERC-regulated natural gas liquids gathering and distribution pipelines and associated above- and below-ground storage facilities. Our natural gas liquids gathering pipelines deliver unfractionated NGLs gathered in Oklahoma, Kansas and the Texas panhandle to our Mid-Continent fractionation facilities in Medford, Oklahoma. Our natural gas liquids distribution pipelines deliver NGL products to the natural gas liquids market hubs in Conway, Kansas, and Mont Belvieu, Texas. Through our acquisition of the natural gas liquids assets from Kinder Morgan, we acquired terminal and storage facilities as well as natural gas liquids and refined petroleum products pipelines that connect our Mid-Continent assets with the Midwest markets near Chicago, Illinois. Our natural gas liquids gathering and distribution pipelines operate in Oklahoma, Kansas, Nebraska, Missouri, Iowa, Illinois and Texas. We have terminal and storage facilities in Missouri, Nebraska, Iowa and Illinois.

Operating revenue for this segment is primarily derived from transporting product under our FERC-regulated tariffs. Tariffs specify the rates we can charge our customers and the general terms and conditions for NGL transportation service on our pipelines. Our tariffs include specifications regarding the receipt and delivery of NGLs at points along the pipeline systems. We generally charge tariff rates under a FERC-approved indexing methodology, which allows charging rates up to a prescribed ceiling that changes annually based on the year-to-year change in the Producer Price Index for finished goods. The FERC also permits interstate natural gas liquids pipelines to support rates by using a cost-of-service methodology, competitive market price or an agreement with a pipeline's non-affiliated shipper.

Our storage services are offered through a combination of market-based rates and FERC-regulated tariffs and are generally used for operational purposes and to store our customers' NGL products. Under some of our FERC-regulated tariffs, customers are allotted earned storage capacity based upon their utilization of transport services. When a customer exceeds its earned storage capacity, we charge the customer an excess storage fee. In some of our product storage agreements, we may charge customers storage reservation fees to reserve a specific storage capacity or we may charge customers based on the quantity of capacity utilized.

Excluding any gain on sale of assets, operating income from our Natural Gas Liquids Pipelines segment was 9 percent and 7 percent of our consolidated operating income in 2007 and 2006, respectively. We did not have a Natural Gas Liquids Pipelines segment prior to 2006. Our Natural Gas Liquids Pipelines segment had no single external customer from which it received 10 percent or more of consolidated revenues. Intersegment sales accounted for 83 percent and 100 percent of our Natural Gas Liquids Pipelines segment's revenues in 2007 and 2006, respectively.

Market Conditions and Seasonality - Supply - The supply for our Natural Gas Liquids Pipelines segment depends on the pace of crude oil and natural gas drilling activity by producers, the decline rate of existing production, and the liquids content of the natural gas that is produced and processed. Our unfractionated NGLs are primarily gathered from natural gas processing plants in Oklahoma, Kansas and the Texas panhandle. The supply of NGLs gathered are affected by operational or market-driven changes that impact the output of natural gas processing plants to which we are connected. The differential between the composite price of NGL products and the price of natural gas, particularly the differential between the price of ethane and the price of natural gas, may influence processing plant output. Typically, the forward price of ethane compared with the forward price of natural gas provides minimal or no processing spread. However, as the prices settle, the price of ethane to natural gas has historically provided a positive processing spread. During 2007, ethane prices remained above natural gas prices on a relative basis.

Demand - Demand for NGLs and the ability of natural gas processors to successfully and economically sustain their operations impacts the volume of unfractionated NGLs produced by processing plants, which affects the demand for our NGL gathering and distribution services. Propane is subject to weather-related seasonal demand. Other products are affected by economic conditions and the demand associated with the various industries that utilize the commodity, such as butanes and natural gasoline, which are used by the refining industry as blending stocks for motor fuel. Ethane/propane mix is used by the petrochemical industry to produce chemical products, such as plastic, rubber and synthetic fiber.

Commodity Prices - In recent years, crude oil, natural gas and NGL prices have been volatile due to market conditions. We are exposed to market risk associated with adverse changes in the price of NGLs, the basis differential between the Mid-Continent, Chicago, Illinois, and Gulf Coast regions, and the relative price differential between natural gas, unfractionated NGLs and individual NGL products, which impact the distribution of NGL products. When natural gas prices are higher relative to NGL prices, NGL production may decline, which could negatively impact the revenues of our gathering and distribution activities. When the basis differential between the Mid-Continent, Chicago, Illinois, and the Gulf Coast regions are narrow, NGL shipments may decline, resulting in a reduction of transportation revenues.

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Seasonality - Some NGLs gathered and distributed by our natural gas liquids pipeline facilities are subject to weather-related seasonal demand, such as propane, which is primarily used to heat residential properties during the winter heating season and for agricultural purposes such as grain drying in the fall. Demand for normal butane, iso-butane and natural gasoline, which are primarily used by the refining industry as blending stocks for motor fuel, may also be subject to some variability when automotive travel is higher.

Competition - Our Natural Gas Liquids Pipelines segment competes with other pipeline companies and other storage facilities for NGLs. Competition among pipeline companies and NGL storage facilities is based primarily on fees for service and proximity to natural gas liquids supply areas and markets.

Government Regulation - Our interstate natural gas liquids pipelines are regulated by the FERC, which regulates virtually all aspects of this business segment, such as transportation of NGLs and refined products, rates and charges for services, depreciation and amortization policies, and initiation and discontinuation of services. The KCC regulates intrastate transportation of NGLs and refined products in Kansas.

Other

Segment Description - Our Other segment includes Black Mesa, which is a pipeline designed to transport crushed coal suspended in water along 273 miles of pipeline that originates at a coal mine in Kayenta, Arizona, and terminates at the Mohave Generating Station (Mohave) in Laughlin, Nevada. The coal slurry pipeline was the sole source of fuel for Mohave and was fully contracted to Peabody Western Coal until December 31, 2005. The water used by the coal slurry pipeline was supplied from an aquifer in the Navajo Nation and Hopi Tribe joint-use area until December 31, 2005.

On December 31, 2005, Black Mesa’s transportation contract with the coal supplier of Mohave expired, and our coal slurry pipeline operations were shut down. In June 2006, Southern California Edison Company (SCE) completed a comprehensive study of the water source, coal supply and transportation issues, and announced that it would no longer pursue the resumption of plant operations. In February 2007, another Mohave co-owner, Salt River Project, announced it was ending its efforts to return the plant to service. We plan to either divest the Black Mesa pipeline or commence decommissioning of the pipeline during 2008.

ENVIRONMENTAL AND SAFETY MATTERS

Information about our environmental matters is included in Note H of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Pipeline Safety - We are subject to United States Department of Transportation integrity management regulations. The Pipeline Safety Improvement Act requires pipeline companies to perform integrity assessments on segments of a pipeline that pass through densely populated areas or near specifically identified sites that are designated as high consequence areas. To our knowledge, we are substantially in compliance with all material requirements associated with the various regulations.

Air and Water Emissions - The federal Clean Air Act and Clean Water Act and analogous state laws impose restrictions and controls regarding the discharge of pollutants into the air and water in the United States. Under the Clean Air Act, a federal operating permit is required for sources of significant air emissions. We may be required to incur certain capital expenditures for air pollution-control equipment in connection with obtaining or maintaining permits and approvals for sources of air emissions. The Clean Water Act imposes substantial potential liability for the removal and remediation of pollutants discharged in United States water.

Superfund - The Comprehensive Environmental Response, Compensation and Liability Act, also known as CERCLA or Superfund, imposes liability, without regard to fault or the legality of the original act, on certain classes of persons who contributed to the release of a hazardous substance into the environment. These persons include the owner or operator of a facility where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the facility. Under CERCLA, these persons may be liable for the costs of cleaning up the hazardous substances released into the environment, damages to natural resources and the costs of certain health studies.

Chemical Site Security - The United States Department of Homeland Security (Homeland Security) released an interim rule in April 2007 that requires companies to provide reports on sites where certain chemicals, including many hydrocarbon products, are stored. After receiving these reports, Homeland Security will identify which sites are required to implement security measures. Homeland Security is in the initial stages of implementing this rule, and the extent to which the rule will require us to undertake additional expenditures for site security is uncertain at this point.

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Climate Change - Our environmental and climate change strategy focuses on taking steps to minimize the impact of our operations on the environment. These strategies include: (i) maintaining an accurate greenhouse gas emissions inventory, (ii) improving the efficiency of our various pipeline and gas processing facilities, (iii) following developing technologies for emission control, (iv) following developing technologies to capture carbon dioxide to keep it from reaching the atmosphere, and (v) analyzing options for future energy investment.

Currently, operating entities within our Partnership participate in the gathering and processing sector and the transmission sector of the EPA's Natural Gas STAR Program to voluntarily reduce methane emissions. In addition, we continue to focus on reducing methane loss through expanded implementation of best practices across our operations and analyzing options for additional emission reductions, including (i) closing older facilities and routing products to more efficient facilities, (ii) self-imposing permit limits at facilities where operationally feasible, (iii) utilizing electric motors on select compressor applications, and (iv) utilizing methods to limit the release of methane gas during pipeline maintenance and operations.

EMPLOYEES

We do not directly employ any of the persons responsible for managing, operating or providing us with services related to our day-to-day business affairs. We have a service agreement with ONEOK, ONEOK Partners GP and NBP Services (the Services Agreement) under which our operations and the operations of ONEOK and its affiliates can combine or share certain common services in order to operate more efficiently and cost effectively. Under the Services Agreement, ONEOK provides us an equivalent type and amount of services that it provides to its other affiliates, including those services required to be provided pursuant to our Partnership Agreement. ONEOK Partners GP operates our interstate natural gas pipeline assets according to each pipeline's operating agreement. ONEOK Partners GP may purchase services from ONEOK and its affiliates pursuant to the terms of the Services Agreement. As of January 31, 2008, we utilized the services of 1,136 full-time employees in addition to the other resources provided by ONEOK and its affiliates.

AVAILABLE INFORMATION

You can access financial and other information at our website at www.oneokpartners.com. We make available on our website, free of charge, copies of our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, amendments to those reports filed or furnished to the SEC pursuant to Section 13(a) or 15(d) of the Exchange Act and reports of holdings of our securities filed by our officers and directors under Section 16 of the Exchange Act as soon as reasonably practicable after filing such material electronically or otherwise furnishing it to the SEC. Copies of our Code of Business Conduct, Governance Guidelines, Accounting and Financial Reporting Code of Ethics, Partnership Agreement and the written charter of our Audit Committee are also available on our website, and we will make available, free of charge, copies of these documents upon request.

ITEM 1A. RISK FACTORS

Our investors should consider the following risks that could affect us and our business. Although we have tried to discuss key factors, our investors need to be aware that other risks may prove to be important in the future. New risks may emerge at any time, and we cannot predict such risks or estimate the extent to which they may affect our financial performance. Investors should carefully consider the following discussion of risks and the other information included or incorporated by reference in this Annual Report on Form 10-K, including "Forward-Looking Statements," which are included in Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operation.

RISKS INHERENT IN OUR BUSINESS

The volatility of natural gas, crude oil and NGL prices could adversely affect our cash flow.

A significant portion of our revenues are derived from the sale of commodities received as payment for our natural gas gathering and processing services, for transportation and storage of natural gas and NGLs, and for the fractionation of NGLs. As a result, we are sensitive to commodity price fluctuations. Commodity prices have been and are likely to continue to be volatile in the future. High commodity prices and large commodity price spreads may not continue and could drop precipitously in a short period of time. Our commodity prices are subject to wide fluctuations in response to a variety of factors beyond our control, including the following:

- relatively minor changes in the supply of, and demand for, domestic and foreign energy;
- market uncertainty;
- the availability and cost of transportation capacity;

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- the level of consumer product demand;
- geopolitical conditions impacting supply and demand for natural gas and crude oil;
- weather conditions;
- domestic and foreign governmental regulations and taxes;
- the price and availability of alternative fuels;
- speculation in the commodity futures markets;
- overall domestic and global economic conditions;
- the price of natural gas, crude oil, NGL and liquefied natural gas imports; and
- the effect of worldwide energy conservation measures.

These external factors and the volatile nature of the energy markets make it difficult to reliably estimate future prices of commodities and the impact commodity price fluctuations have on our customers and their need for our services. As commodity prices decline, we are paid less for our commodities, thereby reducing our cash flow. In addition, production and related volumes could also decline.

We do not fully hedge against price changes in commodities. This could result in decreased revenues, increased costs and lower margins, adversely affecting our results of operations.

Our businesses are exposed to market risk and the impact of market fluctuations in natural gas, NGLs and crude oil prices. Market risk refers to the risk of loss arising from adverse changes in commodity energy prices. Our primary exposure arises from commodity prices with respect to our processing agreements, the difference between NGL and natural gas prices with respect to our natural gas and NGL transportation, fractionation and exchange agreements, and the differential between the individual NGL products and NGLs in storage utilized by our natural gas liquids operations. To manage the risk from market fluctuations in natural gas, NGL and condensate prices, we use commodity derivative instruments such as futures contracts, swaps and options. However, we do not fully hedge against commodity price changes, and we therefore retain some exposure to market risk. Accordingly, any adverse changes to commodity prices could result in decreased revenue and increased costs.

Our use of financial instruments to hedge market risk may result in reduced income.

We utilize financial instruments to mitigate our exposure to interest rate and commodity price fluctuations. Hedging instruments that are used to reduce our exposure to interest rate fluctuations could expose us to risk of financial loss where we have contracted for variable-rate swap instruments to hedge fixed-rate instruments and the variable rate exceeds the fixed rate. In addition, these hedging arrangements may limit the benefit we would otherwise receive if we have contracted for fixed-rate swap agreements to hedge variable-rate instruments and the variable rate falls below the fixed rate. Hedging arrangements that are used to reduce our exposure to commodity price fluctuations may limit the benefit we would otherwise receive if market prices for natural gas and NGLs exceed the stated price in the hedge instrument for these commodities.

Growing our business by constructing new pipelines and new processing and treating facilities or making modifications to our existing facilities subjects us to construction risks and risks that adequate natural gas or NGL supplies will not be available upon completion of the facilities.

One of the ways we intend to grow our business is through the construction of new pipelines and new gathering, processing, storage and fractionation facilities and through modifications to our existing pipelines and existing gathering, processing, storage and fractionation facilities. The construction and modification of pipelines and gathering, processing, storage and fractionation facilities requires the expenditure of significant amounts of capital, which may exceed our estimates, and involves numerous regulatory, environmental, political and legal uncertainties. Construction projects in our industry may increase demand on labor and material which may in turn impact our costs and schedule. If we undertake these projects, we may not be able to complete them on schedule or at the budgeted cost. Additionally, our revenues may not increase immediately upon the expenditure of funds on a particular project. For instance, if we build a new pipeline, the construction will occur over an extended period of time, and we will not receive any material increases in revenues until after completion of the project. We may have only limited natural gas or NGL supplies committed to these facilities prior to their construction. Additionally, we may construct facilities to capture anticipated future growth in production in a region in which anticipated production growth does not materialize. We may also rely on estimates of proved reserves in our decision to construct new pipelines and facilities, which may prove to be inaccurate because there are numerous uncertainties inherent in estimating quantities of proved reserves. As a result, new facilities may not be able to attract enough natural gas or NGLs to achieve our expected investment return, which could adversely affect our results of operations and financial condition.

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Our inability to execute growth and development projects and acquire new assets could reduce cash distributions to our unitholders.

Our primary business objectives are to generate cash flow sufficient to pay quarterly cash distributions to our unitholders and to increase our quarterly cash distributions over time. Our ability to maintain and grow our distributions to unitholders depends on the growth of our existing businesses and strategic acquisitions. Accordingly, if we are unable to implement business development opportunities and finance such activities on economically acceptable terms, our future growth will be limited, which could adversely impact our results of operations.

Our operations are subject to operational hazards and unforeseen interruptions, which could adversely affect our business and for which we may not be adequately insured.

Our operations are subject to all of the risks and hazards typically associated with the operation of natural gas and natural gas liquids gathering and transportation pipelines, storage facilities, and processing and fractionation plants. Operating risks include, but are not limited to, leaks, pipeline ruptures, the breakdown or failure of equipment or processes, and the performance of facilities below expected levels of capacity and efficiency. Other operational hazards and unforeseen interruptions include adverse weather conditions, accidents, the collision of equipment with our pipeline facilities (for example, this may occur if a third party were to perform excavation or construction work near our facilities), and catastrophic events such as explosions, fires, earthquakes, floods or other similar events beyond our control. It is also possible that our infrastructure facilities could be direct targets or indirect casualties of an act of terrorism. A casualty occurrence might result in injury or loss of life, extensive property damage or environmental damage. Liabilities incurred, and interruptions to the operation of our pipeline caused by such an event, could reduce revenues generated by us and increase expenses, thereby impairing our ability to meet our obligations. Insurance proceeds may not be adequate to cover all liabilities or expenses incurred or revenues lost.

If the level of drilling and production in the Mid-Continent, Rocky Mountain and Gulf Coast regions substantially declines, our volumes and revenues could decline.

Our ability to maintain or expand our businesses depends largely on the level of drilling and production in the Mid-Continent, Rocky Mountain and Gulf Coast regions. Drilling and production are impacted by factors beyond our control, including:

- demand for natural gas and refinery-grade crude oil;
- producers' desire and ability to obtain necessary permits in a timely and economic manner;
- natural gas field characteristics and production performance;
- surface access and infrastructure issues; and
- capacity constraints on natural gas, crude oil and natural gas liquids pipelines from the producing areas and our facilities.

In addition, drilling and production are impacted by environmental regulations governing water discharge. If the level of drilling and production in any of these regions substantially declines, our volumes and revenue could be reduced.

If production from the Western Canada Sedimentary Basin remains flat or declines and demand for natural gas from the Western Canada Sedimentary Basin is greater in market areas other than the Midwestern United States, demand for our interstate transportation services could significantly decrease.

We depend on natural gas supply from the Western Canada Sedimentary Basin because our interstate pipelines primarily transport Canadian natural gas from the Western Canada Sedimentary Basin to the Midwestern U.S. market area. If demand for natural gas increases in Canada or other markets not served by our pipelines and production remains flat or declines, demand for transportation service on our interstate natural gas pipelines could decrease significantly, which could adversely impact our results of operations.

Pipeline integrity programs and repairs may impose significant costs and liabilities.

In December 2003, the United States Department of Transportation issued a final rule requiring pipeline operators to develop integrity management programs for intrastate and interstate natural gas and natural gas liquids pipelines located near high consequence areas, where a leak or rupture could do the most harm. The final rule requires operators to perform ongoing assessments of pipeline integrity; identify and characterize applicable threats to pipeline segments that could impact a high consequence area; improve data collection, integration and analysis; repair and remediate the pipeline as necessary; and implement preventive and mitigating actions. The final rule incorporates the requirements of the Pipeline Safety Improvement Act of 2002 and became effective in January 2004. The results of these testing programs could cause us to

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incur significant capital and operating expenditures to make repairs or take remediation, preventive or mitigating actions that are determined to be necessary.

Our business is subject to increased regulatory oversight and potential penalties.

The natural gas industry historically has been heavily regulated; therefore, there is no assurance that a more stringent regulatory approach will not be pursued by the FERC and U.S. Congress, especially in light of previous market power abuse by certain companies engaged in interstate commerce. In response to this issue, the U.S. Congress, in the Energy Policy Act of 2005 (EPACT), developed requirements intended to ensure that the energy market is not impacted by the exercise of market power or manipulative conduct. The FERC then adopted the Market Manipulation Rules to implement the authority granted under EPACT. These rules are intended to prohibit fraud and manipulation and are subject to broad interpretation. EPACT also gave the FERC increased penalty authority for violations.

Our regulated natural gas pipelines' transportation rates are subject to review and possible adjustment by federal and state regulators.

Our regulated pipelines are subject to extensive regulation by the FERC and state regulatory agencies, which regulate most aspects of our pipeline business, including our transportation rates. Under the Natural Gas Act, interstate transportation rates must be just and reasonable and not unduly discriminatory. Under Northern Border Pipeline's 2006 rate case settlement, there is a three-year moratorium preventing Northern Border Pipeline from filing rate cases and the participants from challenging Northern Border Pipeline's rates, and a requirement that Northern Border Pipeline file a rate case within six years.

Our regulated pipeline companies have recorded certain assets that may not be recoverable from our customers.

Accounting policies for FERC-regulated companies permit certain assets that result from the regulated ratemaking process to be recorded on our balance sheet that could not be recorded under GAAP for nonregulated entities. We consider factors such as regulatory changes and the impact of competition to determine the probability of future recovery of these assets. If we determine future recovery is no longer probable, we would be required to write off the regulatory assets at that time.

Our operations are subject to federal and state laws and regulations relating to the protection of the environment, which may expose us to significant costs and liabilities.

The risk of incurring substantial environmental costs and liabilities is inherent in our business. Our operations are subject to extensive federal, state and local laws and regulations governing the discharge of materials into, or otherwise relating to the protection of, the environment. Examples of these laws include:

- the federal Clean Air Act and analogous state laws that impose obligations related to air emissions;
- the federal Clean Water Act and analogous state laws that regulate discharge of wastewaters from our facilities to state and federal waters;
- the federal Comprehensive Environmental Response, Compensation and Liability Act and analogous state laws that regulate the cleanup of hazardous substances that may have been released at properties currently or previously owned or operated by us or locations to which we have sent waste for disposal; and
- the federal Resource Conservation and Recovery Act and analogous state laws that impose requirements for the handling and discharge of solid and hazardous waste from our facilities.

Various governmental authorities, including the United States EPA, have the power to enforce compliance with these laws and regulations and the permits issued under them. Violators are subject to administrative, civil and criminal penalties, including civil fines, injunctions or both. Joint and several, strict liability may be incurred without regard to fault under the Comprehensive Environmental Response, Compensation and Liability Act, Resource Conservation and Recovery Act and analogous state laws for the remediation of contaminated areas.

There is an inherent risk of incurring environmental costs and liabilities in our business due to our handling of the products we gather, transport and process, air emissions related to our operations, historical industry operations and waste disposal practices, some of which may be material. Private parties, including the owners of properties through which our pipeline systems pass, may have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage arising from our operations. Some sites we operate are located near current or former third-party hydrocarbon storage and processing operations, and there is a risk that contamination has migrated from those sites to ours. In addition, increasingly strict laws, regulations and enforcement policies could significantly increase our compliance costs and the cost of any remediation that may become

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necessary, some of which may be material. Additional information is included under Item 1, Business under "Environmental and Safety Matters" and in Note H of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Our insurance may not cover all environmental risks and costs or may not provide sufficient coverage in the event an environmental claim is made against us. Our business may be adversely affected by increased costs due to stricter pollution control requirements or liabilities resulting from non-compliance with required operating or other regulatory permits. New environmental regulations might also adversely affect our products and activities, and federal and state agencies could impose additional safety requirements, all of which could materially affect our profitability.

In the competition for customers, we may have significant levels of uncontracted or discounted transportation capacity on our natural gas and natural gas liquids pipelines.

Our natural gas and natural gas liquids pipelines compete with other pipelines for natural gas and natural gas liquids supplies delivered to the markets we serve. As a result of competition, we may have significant levels of uncontracted or discounted capacity on our pipelines, which could adversely impact our results of operations.

We are exposed to the credit risk of our customers, and our credit risk management may not be adequate to protect against such risk.

We are subject to the risk of loss resulting from nonpayment and/or nonperformance by our customers. Our customers are predominantly producers, NGL end users and marketers that may experience deterioration of their financial condition as a result of changing market conditions or financial difficulties that could impact their credit worthiness or ability to pay us for our services. We assess the credit worthiness of our customers and obtain security as we deem appropriate. If we fail to adequately assess the credit worthiness of existing or future customers, unanticipated deterioration in their credit worthiness and any resulting nonpayment and/or nonperformance could adversely impact our results of operations. In addition, if any of our customers file for bankruptcy protection, our results of operations may be negatively impacted.

RISKS INHERENT IN AN INVESTMENT IN US

The issuance of Class B units to ONEOK in connection with the acquisition of the ONEOK Energy Assets diluted our then current unitholders' ownership interests.

In connection with the acquisition of the ONEOK Energy Assets, we issued approximately 36.5 million Class B limited partner units to ONEOK. The issuance of the Class B units decreased our then current common unitholders' proportionate ownership interest in us. The Class B units are eligible to convert into common units on a one-for-one basis at ONEOK's option due to approval of such conversion by our common unitholders at a special meeting of common unitholders held in March 2007.

In addition, ONEOK may, from time to time, sell all or a portion of its common units. Sales of substantial amounts of its common units, or the anticipation of such sales, could lower the market price of our common units and may make it more difficult for us to sell our equity securities in the future at a time and price that we deem appropriate.

ONEOK could withdraw the waiver of its right to receive, on its Class B units, 110 percent of the distributions paid with respect to our common units.

At a special meeting of the holders of our common units, adjourned to May 10, 2007, the proposed amendments to our Partnership Agreement were not approved by the required two-thirds affirmative vote of our outstanding units, excluding the common units and Class B limited partner units held by ONEOK and its affiliates. As a result, effective April 7, 2007, ONEOK, as the sole holder of our Class B limited partner units, became entitled to receive increased quarterly distributions on its Class B units equal to 110 percent of the distributions paid with respect to our common units.

On June 21, 2007, ONEOK waived its right to receive the increased quarterly distributions on the Class B units for the period of April 7, 2007, through December 31, 2007, and continuing thereafter until ONEOK gives us no less than 90 days advance notice that it has withdrawn its waiver. ONEOK could withdraw such waiver and begin receiving such increased distributions, effective with respect to any distribution on the Class B units declared or paid on or after 90 days following delivery of the notice.

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If our unitholders vote to remove ONEOK or its affiliates as our general partner, quarterly distributions and distributions payable to ONEOK upon liquidation of the Class B units would increase.

Since the proposed amendments to our Partnership Agreement were not approved by the requisite number of our common unitholders, if our common unitholders vote at any time to remove ONEOK or its affiliates as our general partner, quarterly distributions payable on the Class B limited partner units would increase to 123.5 percent of the distributions payable with respect to the common units, and distributions payable upon liquidation of the Class B limited partner units would increase to 123.5 percent of the distributions payable with respect to the common units.

We do not operate all of our assets nor do we directly employ any of the persons responsible for providing us with administrative, operating and management services. This reliance on others to operate our assets and to provide other services could adversely affect our business and operating results.

We rely on ONEOK, ONEOK Services Company and ONEOK Partners GP to provide us with administrative, operating and management services. We have a limited ability to control our operations and the associated costs of such operations. The success of these operations depends on a number of factors that are outside our control, including the competence and financial resources of the provider. ONEOK, ONEOK Services Company and ONEOK Partners GP may outsource some or all of these services to third parties, and a failure to perform by these third-party providers could lead to delays in or interruptions of these services. Should ONEOK, ONEOK Services Company and ONEOK Partners GP not perform their respective contractual obligations, we may have to contract elsewhere for these services, which may cost more than we are currently paying. In addition, we may not be able to obtain the same level or kind of service or retain or receive the services in a timely manner, which may impact our ability to perform under our contracts and negatively affect our business and operating results. Our reliance on ONEOK, ONEOK Services Company, and ONEOK Partners GP and the third-party providers with which they contract, together with our limited ability to control certain costs, could harm our business and results of operations.

The Board of Directors of our general partner, our general partner and its affiliates have conflicts of interest and limited fiduciary duties, which may permit them to favor their own interests.

ONEOK owns 100 percent of our general partner interest and a 43.7 percent limited partner interest in us. Although ONEOK, through the Board of Directors of our general partner, has a fiduciary duty to manage us in a manner beneficial to us and our unitholders, the Board of Directors of ONEOK has a fiduciary duty to manage our general partner in a manner beneficial to ONEOK. One member of the Board of Directors of our general partner is also a member of ONEOK's Board of Directors. Conflicts of interest may arise between our general partner and its affiliates and between us and our unitholders. In resolving these conflicts, our general partner may favor its own interests and the interests of its affiliates over the interests of our unitholders as long as it does not take action that conflicts with our Partnership Agreement or its limited fiduciary duties. These conflicts include, among others, the following situations:

- our general partner, which is owned by ONEOK, and the Board of Directors of our general partner are allowed to take into account the interests of parties other than us in resolving conflicts of interest, which has the effect of limiting their fiduciary duties to our unitholders;
- our Partnership Agreement limits the liability and reduces the fiduciary duties of the members of the Board of Directors of our general partner and also restricts the remedies available to our unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty;
- the Board of Directors of our general partner determines the amount and timing of our cash reserves, asset purchases and sales, capital expenditures, borrowings and issuances of additional partnership securities, each of which can affect the amount of cash that is distributed to our unitholders;
- the Board of Directors of our general partner approves the amount and timing of any capital expenditures and determines whether they are maintenance capital expenditures or growth capital expenditures, which can affect the amount of cash that is distributed to our unitholders;
- the Board of Directors of our general partner may cause us to borrow funds in order to permit the payment of cash distributions, even if the purpose or effect of the borrowing is to make incentive distributions;
- the Board of Directors of our general partner and its Audit Committee determine which costs incurred by the Board of Directors, our general partner and its affiliates are reimbursable by us;
- our Partnership Agreement does not restrict the members of the Board of Directors of our general partner from causing us to pay the Board of Directors, our general partner or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf;
- our general partner may exercise its limited right to call and purchase common units if it and its affiliates own more than 80 percent of the common units; and

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- the Board of Directors and Audit Committee of our general partner decide whether to retain separate counsel, accountants or others to perform services for us.

Our general partner and its affiliates may compete directly with us and have no obligation to present business opportunities to us.

ONEOK and its affiliates are not prohibited from owning assets or engaging in businesses that compete directly or indirectly with us. ONEOK may acquire, construct or dispose of additional midstream or other assets in the future without any obligation to offer us the opportunity to purchase or construct any of those assets. In addition, under our Partnership Agreement, the doctrine of corporate opportunity, or any analogous doctrine, will not apply to ONEOK and its affiliates. As a result, neither ONEOK nor any of its affiliates has any obligation to present business opportunities to us.

Our Partnership Agreement limits our general partner's fiduciary duties to our unitholders and restricts the remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our Partnership Agreement contains provisions that reduce the standards to which our general partner would otherwise be held by state fiduciary duty law. For example, our Partnership Agreement:

- permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner. This entitles our general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner. Examples include the exercise of its limited call right, its voting rights with respect to the units it owns, its registration rights and its determination (through its Board of Directors) whether or not to consent to any merger or consolidation of us;
- provides that our general partner will not have any liability to us or our unitholders for decisions made in its capacity as general partner so long as it acted in "good faith," meaning it believed the decision was in our best interests;
- provides that our general partner is entitled to make other decisions in "good faith" if it reasonably believes that the decision is in our best interests;
- provides generally that affiliated transactions and resolutions of conflicts of interest not approved by the Audit Committee and not involving a vote of unitholders must be on terms no less favorable to us than those generally being provided to or available from unrelated third parties or be "fair and reasonable" to us, as determined by our general partner in "good faith," and that, in determining whether a transaction or resolution is "fair and reasonable," our general partner may consider the totality of the relationships between the parties involved, including other transactions that may be particularly advantageous or beneficial to us; and
- provides that our general partner and its affiliates, officers and directors will not be liable for monetary damages to us or our limited partners for any acts or omissions so long as such person acted in "good faith" and in a manner believed to be in, or not opposed to, the best interest of us and, with respect to any criminal proceeding, had no reasonable cause to believe its conduct was unlawful.

By purchasing a common unit, a common unitholder will be bound by the provisions in our Partnership Agreement, including the provisions discussed above.

The control of our general partner may be transferred to a third party without unitholder consent.

Our general partner may transfer its general partner interest to a third party without the consent of the unitholders. Furthermore, our Partnership Agreement does not restrict the ability of our general partner from transferring its interest to a third party. The new members or unitholders, as the case may be, of our general partner would then be in a position to replace the directors of our general partner with their own choices and to control the decisions made by the Board of Directors of our general partner.

Any reduction in our credit ratings could materially and adversely affect our business, financial condition, liquidity and results of operations.

Our senior unsecured long-term debt has been assigned an investment grade rating by Moody's of "Baa2" (Stable) and by S&P of "BBB" (Stable). We will seek to maintain an investment grade rating through prudent capital management and financing structures. However, we cannot provide assurance that any of our current ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances in the future so warrant. Specifically, if Moody's or S&P were to downgrade our long-term rating, particularly below investment grade, our borrowing costs would increase, which would adversely affect our financial results, and our

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potential pool of investors and funding sources could decrease. Ratings from credit agencies are not recommendations to buy, sell or hold our securities. Each rating should be evaluated independently of any other rating.

Increases in interest rates may cause the market price of our common units to decline.

An increase in interest rates may cause a corresponding decline in demand for equity investments in general, and in particular for yield-based equity investments such as our common units. Any such increase in interest rates or reduction in demand for our common units resulting from other more attractive investment opportunities may cause the trading price of our common units to decline.

A downgrade of our credit rating may require us to offer to repurchase certain of our senior notes or may impair our ability to access capital.

We could be required to offer to repurchase certain of our senior notes due 2010 and 2011 at par value, plus any accrued and unpaid interest, if Moody's or S&P rate those senior notes below investment grade (Baa3 for Moody's and BBB- for S&P). Further, the indenture governing our senior notes due 2010 and 2011 includes an event of default upon acceleration of other indebtedness of $25 million or more and the indenture governing our senior notes due 2012, 2016, 2036 and 2037 includes an event of default upon the acceleration of other indebtedness of $100 million or more that would be triggered by such an offer to repurchase. Such an event of default would entitle the trustee or the holders of 25 percent in aggregate principal amount of the outstanding senior notes due 2010, 2011, 2012, 2016, 2036 and 2037 to declare those notes immediately due and payable in full. We may not have sufficient cash on hand to repurchase and repay any accelerated senior notes, which may cause us to borrow money under our credit facilities or seek alternative financing sources to finance the repayments and repurchases. We could also face difficulties accessing capital or our borrowing costs could increase, impacting our ability to obtain financing for acquisitions or capital expenditures, to refinance indebtedness and to fulfill our debt obligations.

Our indebtedness could impair our financial condition and our ability to fulfill our debt obligations.

As of December 31, 2007, we had total indebtedness of approximately $2.7 billion. Our indebtedness could have significant consequences. For example, it could:

- make it more difficult for us to satisfy our obligations with respect to our notes and our other indebtedness, which could in turn result in an event of default on such other indebtedness or our notes;
- impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions or general business purposes;
- diminish our ability to withstand a downturn in our business or the economy;
- require us to dedicate a substantial portion of our cash flow from operations to debt service payments, reducing the availability of cash for working capital, capital expenditures, acquisitions, distributions to partners, general corporate purposes or other purposes;
- limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate; and
- place us at a competitive disadvantage compared with our competitors that have proportionately less debt.

If we are unable to meet our debt service obligations, we could be forced to restructure or refinance our indebtedness, seek additional equity capital or sell assets. We may be unable to obtain financing or sell assets on satisfactory terms, or at all.

We are not prohibited under the indentures governing our senior notes from incurring additional indebtedness. Our incurrence of significant additional indebtedness would exacerbate the negative consequences mentioned above, and could adversely affect our ability to repay our notes and other indebtedness.

We and the Intermediate Partnership have a holding company structure in which our subsidiaries conduct our operations and own our operating assets.

We and the Intermediate Partnership are holding companies, and our subsidiaries conduct all of our operations and own all of our operating assets. Neither we nor the Intermediate Partnership have significant assets other than the partnership interests and the equity in our subsidiaries and Northern Border Pipeline. As a result, our ability to make quarterly distributions and required payments on our indebtedness depends on the performance of our subsidiaries and their ability to distribute funds to us. The ability of our subsidiaries to make distributions to us may be restricted by, among other things, credit facilities, applicable state partnership laws, and other laws and regulations. If we are unable to obtain the funds necessary to make quarterly distributions or required payments on our indebtedness, we may be required to adopt one or more alternatives, such

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as refinancing the indebtedness or seeking alternative financing sources to fund the quarterly distributions and indebtedness payments.

We may issue additional common units without unitholder approval, which would dilute unitholders' ownership interests.

Our general partner, without the approval of our unitholders, may cause us to issue an unlimited number of additional units, subject to the limitations imposed by the NYSE. The issuance by us of additional common units or other equity securities of equal or senior rank will have the following effects:

- our unitholders' proportionate ownership interest in us will decrease;
- the distribution paid on each unit may decrease;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

Our general partner has a limited call right that may require unitholders to sell their common units at an undesirable time or price.

If at any time our general partner and its affiliates own more than 80 percent of the common units, our general partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price not less than their then-current market price. As a result, unitholders may be required to sell their common units at an undesirable time or price and may not receive any return on their investment. Unitholders may also incur a tax liability upon the sale of their units. Our general partner is not obligated to obtain a fairness opinion regarding the value of the common units to be repurchased by it upon exercise of the limited call right. There is no restriction in our Partnership Agreement that prevents our general partner from issuing additional common units and exercising its call right. If our general partner exercised its limited call right, the effect would be to take us private and, if the units were subsequently deregistered, we would no longer be subject to the reporting requirements of the Exchange Act.

Our Partnership Agreement restricts the voting rights of unitholders owning 20 percent or more of our common units.

Our Partnership Agreement restricts unitholders' voting rights by providing that any units held by a person that owns 20 percent or more of any class of units then outstanding, other than our general partner and its affiliates, cannot vote on any matter. Our Partnership Agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders' ability to influence the manner or direction of management.

Unitholders may not have limited liability if a court finds that unitholder action constitutes control of our business. Unitholders may also have liability to repay distributions.

As a limited partner in a limited partnership organized under Delaware law, unitholders could be held liable for our obligations to the same extent as a general partner if they participate in the "control" of our business. Our general partner generally has unlimited liability for our obligations, such as our debts and environmental liabilities, except for our contractual obligations that are expressly made without recourse to our general partner. In addition, the Delaware Revised Uniform Limited Partnership Act provides that, under some circumstances, a unitholder may be liable to us for the amount of a distribution for a period of three years from the date of the distribution. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the states in which we do business.

TAX RISKS

Our tax treatment depends on our status as a partnership for federal income tax purposes. Additionally, we are only subject to entity level taxation in the state of Texas. If the IRS were to treat us as a corporation or if we to become subject to a material amount of entity level taxation for state tax purposes, then our cash available for distribution to our common unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS on this matter.

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If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35 percent, and we likely would pay state taxes as well. Distributions to our unitholders would generally be taxed again as corporate distributions, and no income, gains, losses or deductions would flow through to our unitholders. Because a tax would be imposed upon us as a corporation, the cash available for distributions to our common unitholders would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the after-tax return to our common unitholders, likely causing a substantial reduction in the value of our common units.

Current law may change, causing us to be treated as a corporation for federal income tax purposes or otherwise subjecting us to entity level federal taxation. In addition, several states are evaluating ways to subject partnerships to entity level taxation through the imposition of state income, franchise or other forms of taxation. For example, we became subject to a new entity level tax on the portion of our income generated in Texas beginning in 2007. Specifically, the Texas margin tax was imposed at a maximum effective rate of 0.7 percent of our gross income apportioned to Texas. Imposition of such tax on us by Texas, or any other state, reduces the cash available for distribution to our common unitholders.

A successful IRS contest of the federal income tax positions we take may adversely impact the market for our common units, and the costs of any contest will be borne by our unitholders and general partner.

We have not requested any ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter affecting us. The IRS may adopt positions that differ from the federal income tax positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with some or all of the positions we take. Any contest with the IRS may adversely impact the taxable income reported to our unitholders and the income taxes they are required to pay. As a result, any such contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade. In addition, the costs of any such contest with the IRS will result in a reduction in cash available to pay distributions to our unitholders and our general partner and thus will be borne indirectly by our unitholders and our general partner.

A unitholder may be required to pay taxes on a share of our income even if the unitholder does not receive any cash distributions from us.

A unitholder will be required to pay federal income taxes and, in some cases, state and local income taxes on the unitholder's share of our taxable income, whether or not the unitholder receives cash distributions from us. A unitholder may not receive cash distributions from us equal to the unitholder's share of our taxable income or even equal to the actual tax liability that results from the unitholder's share of our taxable income.

The taxable gain or loss on the disposition of our common units could be different than expected.

A unitholder will recognize a gain or loss on the sale of common units equal to the difference between the amount realized and the unitholder's tax basis in those common units. A unitholder's amount realized will be measured by the sum of the cash or the fair market value of other property received plus the unitholder's share of our nonrecourse liabilities. Because the amount realized includes a unitholder's share of our nonrecourse liabilities, the gain recognized on the sale of common units could result in a tax liability in excess of any cash received from the sale. Prior distributions to a unitholder in excess of the total net taxable income allocated to a unitholder for a common unit, which decreased the tax basis in that common unit, will, in effect, become taxable income to a unitholder if the common unit is sold at a price greater than the tax basis in that common unit, even if the price received is less than the original cost. A substantial portion of the amount realized, whether or not representing a gain, may be ordinary income to a unitholder. Should the IRS successfully contest some positions we take, unitholders could recognize more gain on the sale of units than would be the case under those positions, without the benefit of decreased income in prior years.

Tax-exempt entities, regulated investment companies and non-U.S. persons face unique tax issues from owning common units that may result in adverse tax consequences to them.

Investment in common units by tax-exempt entities, such as individual retirement accounts, regulated investment companies known as mutual funds, and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations exempt from federal income tax, including individual retirement accounts and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non-U.S. persons may be subject to U.S. withholding taxes. Non-U.S. persons will be required to file U.S. federal income tax returns and pay tax on their share of our taxable income.

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We will treat each purchaser of units as having the same tax benefits without regard to the units purchased. The IRS may challenge this treatment, which could adversely affect the value of the common units.

Because we cannot match transferors and transferees of common units, we have adopted depreciation and amortization positions that may not conform to all aspects of existing Treasury regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to unitholders. It also could affect the timing of these tax benefits or the amount of gain from a unitholder's sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to a unitholder's tax returns.

Unitholders will be subject to state and local taxes and return filing requirements as a result of investing in our common units.

In addition to federal income taxes, unitholders will be subject to other taxes, such as state and local income taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property. Unitholders will be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions and may be subject to penalties for failure to comply with those requirements. We may own property or conduct business in other states or foreign countries in the future. It is each unitholder's responsibility to file all United States federal, state and local tax returns and foreign tax returns, as applicable.

Some of the states in which we do business or own property may require us to, or we may elect to, withhold a percentage of income from amounts to be distributed to a unitholder who is not a resident of the state. Withholding, the amount of which may be greater or less than a particular unitholder's income tax liability to the state, generally does not relieve the non-resident unitholder from the obligation to file an income tax return. Amounts withheld may be treated as if distributed to unitholders for purposes of determining the amounts distributed by us. Our counsel has not rendered an opinion on the state and local tax consequences of an investment in our units.

The sale or exchange of 50 percent or more of the total interest in our capital and profits within a 12-month period will result in the termination of our Partnership for federal income tax purposes.

We will be considered to have terminated for federal income tax purposes if there is a sale or exchange of 50 percent or more of the total interests in our capital and profits within a 12-month period. Our termination would, among other things, result in the closing of our taxable year for all unitholders and could result in a deferral of depreciation deductions allowable in computing our taxable income.

We have adopted certain valuation methodologies that may result in a shift of income, gain, loss and deduction between the general partner and the unitholders. The IRS may challenge this treatment, which could adversely affect the value of our limited partner units.

When we issue additional units or engage in certain other transactions, we determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our general partner. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and the general partner, which may be unfavorable to such unitholders. Moreover, under our current valuation methods, subsequent purchasers of common units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between the general partner and certain of our unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from our unitholders' sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

Our treatment of a purchaser of common units as having the same tax benefits as the seller could be challenged, resulting in a reduction in value of the common units.

Because we cannot match transferors and transferees of common units, we are required to maintain the uniformity of the economic and tax characteristics of these units in the hands of the purchasers and sellers of these units. We do so by adopting certain depreciation conventions that do not conform to all aspects of the United States Treasury regulations. An IRS challenge to these conventions could adversely affect the tax benefits to a unitholder of ownership of the common units and

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could have a negative impact on their value or result in audit adjustments to our unitholders' tax returns.

ITEM 1B. UNRESOLVED STAFF COMMENTS

Not applicable.

ITEM 2. PROPERTIES

Natural Gas Gathering and Processing

Our operations include gathering of raw natural gas production from oil and natural gas wells. We gather raw natural gas in the Mid-Continent region, which includes the Anadarko Basin of Oklahoma and the Hugoton and Central Kansas Uplift Basins of Kansas. We also gather raw natural gas in three producing basins in the Rocky Mountain region: (i) the Williston Basin, which spans portions of Montana, North Dakota and the Canadian province of Saskatchewan, (ii) the Powder River Basin of Wyoming and (iii) the Wind River Basin of Wyoming.

In the Mid-Continent and Rocky Mountain regions, raw natural gas is compressed and transported through pipelines to processing facilities where volumes are aggregated, treated and processed to remove water vapor, solids and other contaminants, and the unfractionated NGLs are extracted. In some cases, the unfractionated NGLs are separated at the processing facility into NGL products, through fractionation, and the NGL products are sold to refineries or local markets. The residue gas, which consists primarily of methane, is compressed and delivered to natural gas pipelines for transportation to the end user. The unfractionated NGLs not sold in the local markets are delivered to natural gas liquids pipelines where they are transported, fractionated and delivered to the end user.

Our Natural Gas Gathering and Processing segment assets consist of the following:

- approximately 10,100 miles and 4,200 miles of gathering pipelines with capacity owned, leased or contracted for in the Mid-Continent and Rocky Mountain regions, respectively,
- nine active processing plants, with approximately 645 MMcf/d of owned processing capacity in the Mid-Continent region, and four active processing plants with approximately 80 MMcf/d of owned, leased or contracted processing capacity in the Rocky Mountain region, and
- approximately 18 MBbl/d of natural gas liquids fractionation capacity in the Mid-Continent and Rocky Mountain regions.

Our natural gas processing operations utilize straddle and field gas processing plants to extract NGLs from raw natural gas and remove water vapor and other contaminants from the raw natural gas stream. A straddle gas processing plant is situated on a pipeline system and relies on the pipeline's natural gas throughput volume, which subjects the plant to increased supply risk as it is dependent upon the throughput of a single pipeline rather than several supply sources. Field gas processing plants gather raw natural gas from multiple producing wells.

On January 1, 2007, the Bushton Plant was temporarily idled. Volumes available for processing at this straddle plant have declined due to contract terminations and natural field declines, which made it more efficient to process the remaining gas at other facilities. We have contracted for all of the capacity of the plant from ONEOK. We are in the process of adding new facilities at or near the plant, in conjunction with other changes that are being made to the plant. The plant currently has 1.0 Bcf/d processing capacity and 80 MBbl/d fractionation capacity. The plant and other nearby facilities are expected to resume operations in mid-2008, and will primarily provide natural gas liquids fractionation and storage services as a part of our Natural Gas Liquids Gathering and Fractionation segment.

Natural Gas Pipelines

Our Natural Gas Pipelines segment gathers and transports natural gas through regulated interstate and intrastate natural gas transmission pipelines, stores natural gas, and operates non-processable natural gas gathering facilities.

Our interstate natural gas pipeline assets transport natural gas through FERC-regulated interstate natural gas pipelines in Montana, North Dakota, South Dakota, Minnesota, Wisconsin, Illinois, Indiana, Kentucky, Tennessee, Oklahoma, Texas and New Mexico. Our interstate pipelines include Midwestern Gas Transmission, Guardian Pipeline, Viking Gas Transmission, OkTex Pipeline and a 50 percent interest in Northern Border Pipeline. Midwestern Gas Transmission is a bi-directional system that interconnects with Tennessee Gas Transmission near Portland, Tennessee, and several interstate pipelines near Joliet, Illinois. Viking Gas Transmission transports natural gas from an interconnection with TransCanada near Emerson,

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Manitoba, to an interconnection with ANR Pipeline Company near Marshfield, Wisconsin. Guardian Pipeline interconnects with several pipelines in Joliet, Illinois, and with a local distribution company in Ixonia, Wisconsin. OkTex Pipeline has interconnects in Oklahoma, New Mexico and Texas.

Our intrastate natural gas pipeline assets in Oklahoma have access to the major natural gas producing areas and transport natural gas throughout the state. In Texas, our intrastate pipelines are connected to the major natural gas producing areas in the Texas panhandle and the Permian Basin and transport natural gas to the Waha Hub, where other pipelines may be accessed for transportation east to the Houston Ship Channel market, north into the Mid-Continent market and west to the California market. We also have intrastate pipelines that access the major natural gas producing area in south central Kansas.

Our storage assets include five underground natural gas storage facilities in Oklahoma, three underground natural gas storage facilities in Kansas and three underground natural gas storage facilities in Texas. One of our natural gas storage facilities has been idle since 2001 following natural gas explosions and eruptions of natural gas geysers in Hutchinson, Kansas. We began injecting brine into the facility in the first quarter of 2007 in order to ensure the long-term integrity of the facility. Monitoring of the facility and review of the data for the geoengineering study are ongoing.

Our Natural Gas Pipelines segment’s assets consist of the following:

- approximately 1,290 miles of FERC-regulated interstate natural gas pipelines with approximately 2.4 Bcf/d of peak transportation capacity,
- approximately 5,630 miles of intrastate natural gas gathering and state-regulated intrastate transmission pipelines with peak transportation capacity of approximately 2.9 Bcf/d,
- approximately 51.6 Bcf of total active working gas storage capacity, and
- our 50 percent interest in Northern Border Pipeline.

Natural Gas Liquids Gathering and Fractionation

Our natural gas liquids gathering and fractionation assets consist of facilities that gather, fractionate and treat NGLs and store NGL purity products primarily in Oklahoma, Kansas and Texas, as well as store and fractionate NGLs in Mont Belvieu, Texas. Most of the pipeline-connected natural gas processing plants in Oklahoma, Kansas and the Texas panhandle, which extract NGLs from raw natural gas, are connected to our gathering systems. The natural gas liquids operations gather these unfractionated NGLs and deliver them to our fractionators. The unfractionated NGLs are then separated into NGL products, through a fractionation process, to realize the greater economic value of the NGL products. The individual NGL products are then stored or distributed to petrochemical manufacturers, refineries and propane distributors. Our fractionation and storage facilities are connected to the key natural gas liquids market centers in Conway, Kansas, and Mont Belvieu, Texas, by FERC-regulated interstate natural gas liquids pipelines, which are part of our Natural Gas Liquids Pipelines segment.

Our Natural Gas Liquids Gathering and Fractionation segment assets consist of the following:

- approximately 2,570 miles of owned and contracted natural gas liquids gathering pipelines with peak capacity of approximately 270 MBbl/d,
- approximately 163 miles of natural gas liquids distribution pipelines with peak transportation capacity of approximately 62 MBbl/d,
- interests in four natural gas liquids fractionators with proportional operating capacity of approximately 399 MBbl/d,
- one 9 MBbl/d isomerization unit, and
- seven owned or leased storage facilities in Oklahoma, Kansas and Texas with operating storage capacity of approximately 24,600 MBbl.

Natural Gas Liquids Pipelines

Our natural gas liquids gathering pipelines deliver unfractionated NGLs gathered in Oklahoma, Kansas and the Texas panhandle to our Mid-Continent fractionation facilities in Medford, Oklahoma. Our natural gas liquids distribution pipelines deliver NGL products to the natural gas liquids market hubs in Conway, Kansas, and Mont Belvieu, Texas. Through our acquisition of an interstate natural gas liquids and refined petroleum products pipeline system and related assets from a subsidiary of Kinder Morgan, we acquired terminal and storage facilities as well as natural gas liquids and refined petroleum products pipelines that connect our Mid-Continent assets with the Midwest markets near Chicago, Illinois. We operate FERC-regulated natural gas liquids gathering and distribution pipelines in Oklahoma, Kansas, Nebraska, Missouri, Iowa, Illinois and Texas. We have natural gas liquids terminal and storage facilities in Missouri, Nebraska, Iowa and Illinois.

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Our Natural Gas Liquids Pipelines segment's assets consist of the following:

- approximately 720 miles of FERC-regulated natural gas liquids gathering pipelines with peak capacity of approximately 93 MBbl/d,
- approximately 3,350 miles of FERC-regulated natural gas liquids distribution pipelines with peak transportation capacity of 434 MBbl/d,
- eight NGL product terminals in Missouri, Nebraska, Iowa and Illinois, and
- above-and below-ground storage facilities with 978 MBbl operating capacity.

Other

Our Other segment includes Black Mesa, which is a pipeline that was designed to transport crushed coal suspended in water along 273 miles of pipeline that originates at a coal mine in Kayenta, Arizona, and terminates at Mohave in Laughlin, Nevada. We plan to either divest the Black Mesa pipeline or commence decommissioning of the pipeline during 2008.

ITEM 3. LEGAL PROCEEDINGS

Will Price, et al. v. Gas Pipelines, et al. (f/k/a Quinque Operating Company, et al. v. Gas Pipelines, et al.), 26th Judicial District, District Court of Stevens County, Kansas, Civil Department, Case No. 99C30 ("Price I"). Plaintiffs brought suit on May 28, 1999, against Mid-Continent Market Center, Inc., ONEOK Field Services Company, ONEOK WesTex Transmission, L.P. and ONEOK Hydrocarbon, L.P. (formerly Koch Hydrocarbon, LP), as well as approximately 225 other defendants. Plaintiffs sought class certification for its claims for monetary damages that the defendants had underpaid gas producers and royalty owners throughout the United States by intentionally understating both the volume and the heating content of purchased gas. After extensive briefing and a hearing, the Court refused to certify the class sought by plaintiffs. Plaintiffs then filed an amended petition limiting the purported class to gas producers and royalty owners in Kansas, Colorado and Wyoming and limiting the claim to undermeasurement of volumes. Oral argument on the plaintiffs' motion to certify this suit as a class action was conducted on April 1, 2005. The Court has not yet ruled on the class certification issue.

Will Price and Stixon Petroleum, et al. v. Gas Pipelines, et al., 26th Judicial District, District Court of Stevens County, Kansas, Civil Department, Case No. 03C232 ("Price II"). This action was filed by the plaintiffs on May 12, 2003, after the Court had denied class status in Price I. Plaintiffs are seeking monetary damages based upon a claim that 21 groups of defendants, including Mid-Continent Market Center, Inc., ONEOK Field Services Company, ONEOK WesTex Transmission, L.P. and ONEOK Hydrocarbon, L.P. (formerly Koch Hydrocarbon, LP), intentionally underpaid gas producers and royalty owners by understating the heating content of purchased gas in Kansas, Colorado and Wyoming. Price II has been consolidated with Price I for the determination of whether either or both cases may properly be certified as class actions. Oral argument on the plaintiffs' motion to certify this suit as a class action was conducted on April 1, 2005. The Court has not yet ruled on the class certification issue.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

Not applicable.

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PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

MARKET INFORMATION AND HOLDERS

Our equity consists of a 2 percent general partner interest and a 98 percent limited partner interest. Our limited partner interests are represented by our common units, which are listed on the NYSE under the trading symbol "OKS," and our Class B limited partner units. The following table sets forth the high and low closing prices of our common units for the periods indicated.

	Year Ended December 31, 2007		Year Ended December 31, 2006	
	High	**Low**	**High**	**Low**
First Quarter	**$ 67.80**	**$ 62.62**	$ 49.15	$ 42.74
Second Quarter	**$ 72.42**	**$ 66.82**	$ 51.35	$ 47.63
Third Quarter	**$ 70.70**	**$ 58.20**	$ 56.25	$ 49.99
Fourth Quarter	**$ 65.41**	**$ 59.00**	$ 65.91	$ 57.08

At February 20, 2008, there were 902 holders of record of our 46,397,214 outstanding common units.

CASH DISTRIBUTIONS

The following table sets forth the quarterly cash distribution declared and paid on our common and Class B units during the periods indicated.

	Years Ended December 31,	
	2007	**2006**
First Quarter	**$ 0.98**	$ 0.80
Second Quarter	**$ 0.99**	$ 0.88
Third Quarter	**$ 1.00**	$ 0.95
Fourth Quarter	**$ 1.01**	$ 0.97

In January 2008, we increased our cash distribution to $1.025 per unit for the fourth quarter of 2007, which was paid on February 14, 2008, to unitholders of record as of January 31, 2008.

CASH DISTRIBUTION POLICY

Under our Partnership Agreement, we make distributions to our partners with respect to each calendar quarter in an amount equal to 100 percent of available cash within 45 days following the end of each quarter. Available cash generally consists of our cash receipts adjusted for our cash disbursements and net changes to cash reserves. Available cash will generally be distributed 98 percent to limited partners and 2 percent to our general partner. As an incentive, our general partner's percentage interest in quarterly distributions is increased after certain specified target levels are met. Under the incentive distribution provisions, our general partner receives:

- 15 percent of amounts distributed in excess of $0.605 per unit,
- 25 percent of amounts distributed in excess of $0.715 per unit, and
- 50 percent of amounts distributed in excess of $0.935 per unit.

We paid cash distributions to our general and limited partners of $384.6 million for 2007 and $265.5 million for 2006, which included an incentive distribution to our general partner of $47.1 million for 2007 and $23.1 million for 2006. Additional information about our cash distributions is included in Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operation under "Liquidity and Capital Resources," and Item 13, Certain Relationships and Related Transactions, and Director Independence.

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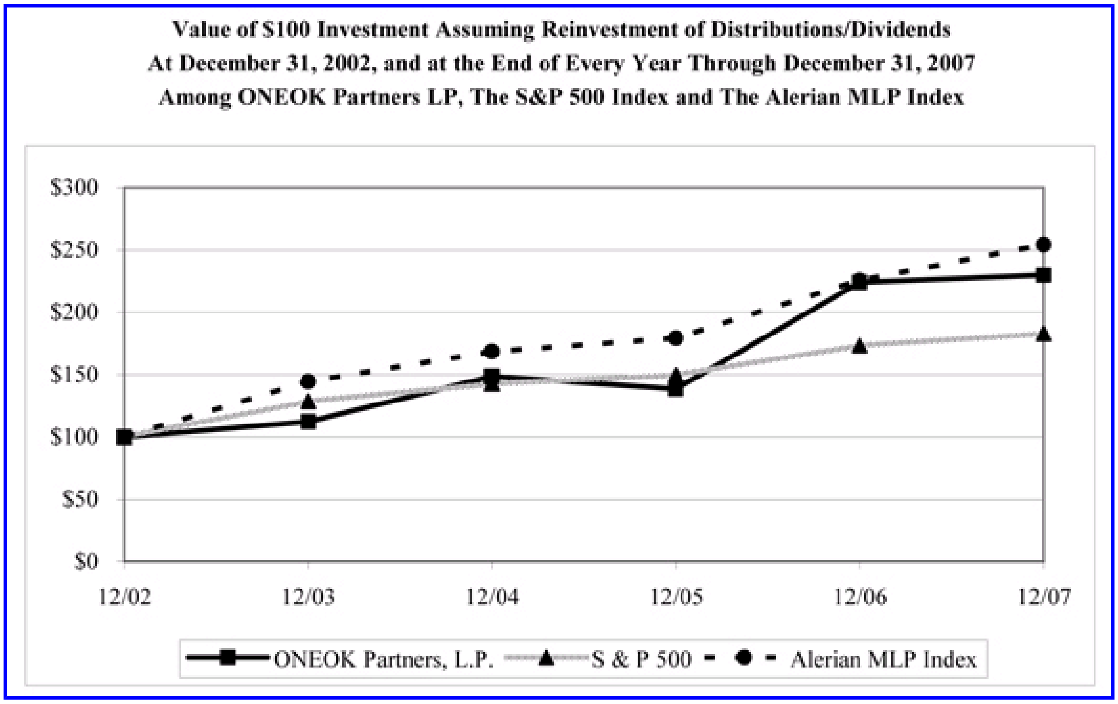
ISSUANCE OF CLASS B UNITS

In April 2006, we issued approximately 36.5 million Class B units to ONEOK as part of the acquisition of the ONEOK Energy Assets. See the discussion of the ONEOK Energy Assets acquisition in Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operation under "Significant Acquisitions and Divestitures." The units issued to ONEOK were the newly created Class B limited partner units. As of April 7, 2007, the Class B limited partner units are no longer subordinated to distributions on our common units and generally have the same voting rights as our common units. See Note B of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for additional information.

The Class B units were not registered in reliance on the exemption from registration with the SEC as set forth in Section 4(2) of the Securities Act of 1933, as amended, as a transaction not involving any public offering.

PERFORMANCE GRAPH

The following performance graph compares the performance of our common units with the S&P 500 Index and the Alerian MLP Index during the period beginning on December 31, 2002, and ending on December 31, 2007. The graph assumes a $100 investment in our common units and in each of the indices at the beginning of the period and a reinvestment of distributions/dividends paid on such investments throughout the period.



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	Cumulative Total Return Years Ending December 31,					
	2002	2003	2004	2005	2006	2007
ONEOK Partners, L.P.	$100.00	$112.19	$148.69	$138.50	$224.08	**$230.01**
S&P 500 Index	$100.00	$128.68	$142.69	$149.70	$173.34	**$182.87**
Alerian MLP Index (a)	$100.00	$144.55	$168.65	$179.30	$225.60	**$254.24**

(a) - The Alerian MLP Index measures the composite performance of the 50 most prominent energy master limited partnerships, and is calculated by Standard & Poor's using a float-adjusted, capitalization-weighted methodology.

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ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth our selected financial data for each of the periods indicated.

	Years Ended December 31,				
	2007	**2006**	**2005**	**2004**	**2003**
	(In thousands of dollars, except per unit data)				
Operating revenue	**$5,831,558**	$4,738,248	$ 703,944	$ 590,383	$ 550,948
Income (loss) from continuing operations	**$ 407,747**	$ 445,186	$ 146,507	$ 140,921	$ (97,149)
Net income (loss)	**$ 407,747**	$ 445,186	$ 147,013	$ 144,720	$ (88,454)
Total assets	**$6,112,065**	$4,921,717	$2,527,766	$2,514,690	$2,570,583
Long-term debt, including current maturities	**$2,617,326**	$2,031,529	$1,123,971	$1,139,358	$1,238,986
Per unit income (loss) from continuing operations	**$ 4.21**	$ 5.01	$ 2.92	$ 2.81	$ (2.27)
Per unit net income (loss)	**$ 4.21**	$ 5.01	$ 2.93	$ 2.89	$ (2.08)
Distributions per unit	**$ 3.98**	$ 3.60	$ 3.20	$ 3.20	$ 3.20

Financial data for 2007 and 2006 is not directly comparable with 2005, 2004 and 2003 due to the significance of the April 2006 ONEOK Transactions. See discussion of acquisitions and dispositions beginning on page 32 under "Significant Acquisitions and Divestitures" in Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operation.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATION

The following discussion and analysis should be read in conjunction with our audited consolidated financial statements and the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

EXECUTIVE SUMMARY

The following discussion highlights some of our achievements and significant issues affecting us this past year. Please refer to the Financial and Operating Results section of Management's Discussion and Analysis of Financial Condition and Results of Operation and the Financial Statements for a complete explanation of the following items.

In July 2007, we announced a series of organizational changes that led to the realignment of our previous business segments. Our financial results are now reported in these four segments: (i) Natural Gas Gathering and Processing, which remains unchanged, (ii) Natural Gas Pipelines, which is comprised of our former interstate natural gas pipelines segment and the natural gas assets of our former pipelines and storage segment, (iii) Natural Gas Liquids Gathering and Fractionation, which remains unchanged, and (iv) Natural Gas Liquids Pipelines, which is comprised of the natural gas liquids assets of our former pipelines and storage segment. Prior periods have been restated to reflect these segment changes. The change reflects the increasing scale of the natural gas liquids business, which has grown significantly since 2006. Our natural gas liquids business is expanding as we integrate the assets acquired in October 2007 from a subsidiary of Kinder Morgan into our Natural Gas Liquids Pipelines segment and complete our other internal growth projects.

In September 2007, we completed an underwritten public debt offering of $600 million to finance the assets acquired from Kinder Morgan and to repay debt outstanding under the 2007 Partnership Credit Agreement, which was incurred to fund our internal growth capital projects. Both the assets acquired from Kinder Morgan and our capital projects are discussed below in the "Significant Acquisitions and Divestitures" and the "Capital Projects" sections.

On January 15, 2008, we declared a cash distribution of $1.025 per unit ($4.10 per unit on an annualized basis), an increase of approximately 5 percent over the $0.98 declared in January 2007.

Net income per unit decreased to $4.21 in 2007, compared with $5.01 in 2006. The decrease in net income per unit for the year is primarily due to the gain on sale of a 20 percent partnership interest in Northern Border Pipeline in the second quarter of 2006. Operating income decreased to $446.8 million in 2007, compared with $511.2 million in 2006. Excluding the gain on sale of assets, operating income increased to $444.8 million in 2007 compared with $395.7 million in 2006. Our Natural Gas Liquids Gathering and Fractionation segment and Natural Gas Liquids Pipelines segment benefited primarily from new supply connections that increased volumes gathered, transported, fractionated and sold. In addition, we benefited from higher product price spreads and higher isomerization price spreads in our Natural Gas Liquids Gathering and Fractionation segment. Our Natural Gas Liquids Pipelines segment benefited from the incremental operating income related to the assets

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acquired from Kinder Morgan in October 2007. These increases were partially offset by decreased natural gas transportation margins in our Natural Gas Pipelines segment, primarily resulting from lower throughput and higher fuel costs. Operating income also decreased in our Natural Gas Gathering and Processing segment, primarily due to lower natural gas volumes processed as a result of contract terminations in late 2006.

SIGNIFICANT ACQUISITIONS AND DIVESTITURES

Acquisition of NGL Pipeline - In October 2007, we completed the acquisition of an interstate natural gas liquids and refined petroleum products pipeline system and related assets from a subsidiary of Kinder Morgan for approximately $300 million, before working capital adjustments. The system extends from Bushton and Conway, Kansas, to Chicago, Illinois, and transports, stores and delivers a full range of NGL and refined products. The FERC-regulated system spans 1,627 miles and has a capacity to transport up to 134 MBbl/d. The transaction includes approximately 978 MBbl of owned storage capacity, eight NGL terminals and a 50 percent ownership of Heartland. ConocoPhillips owns the other 50 percent of Heartland and is the managing partner of the Heartland joint venture, which consists primarily of three refined products terminals and connecting pipelines. Financing for this transaction came from the proceeds of our September 2007 issuance of $600 million 6.85 percent Senior Notes due 2037 (the 2037 Notes). See Note G of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for a discussion on the 2037 Notes. These assets are included in our Natural Gas Liquids Pipelines segment.

ONEOK Transactions - In April 2006, we completed the acquisition and consolidated certain companies comprising ONEOK's former gathering and processing, natural gas liquids, and pipelines and storage segments (collectively, the ONEOK Energy Assets) in a series of transactions (collectively, the ONEOK Transactions). This acquisition is accounted for in our Natural Gas Gathering and Processing, Natural Gas Pipelines, Natural Gas Liquids Gathering and Fractionation, and Natural Gas Liquids Pipelines segments.

Acquisition of ONEOK Energy Assets - We acquired the ONEOK Energy Assets for approximately $3 billion, including $1.35 billion in cash, before adjustments, and approximately 36.5 million Class B limited partner units. The Class B limited partner units and the related general partner interest contribution were valued at approximately $1.65 billion. ONEOK now owns approximately 37.0 million of our limited partner units, which, when combined with its general partner interest, increased its total interest in us to approximately 45.7 percent. We used $1.05 billion drawn under our $1.1 billion, 364-day credit agreement (the Bridge Facility), coupled with the proceeds from the sale of a 20 percent partnership interest in Northern Border Pipeline, to finance the cash portion of the transaction. The assets were recorded at historical cost rather than at fair value since these transactions were between affiliates under common control. These assets and their related operations are included in our consolidated financial statements retroactive to January 1, 2006.

Equity Issuance - In connection with the ONEOK Transactions, we amended our Partnership Agreement to provide for the issuance of Class B limited partner units and issued approximately 36.5 million Class B limited partner units to ONEOK. The Class B limited partner units were issued on April 6, 2006. For more information regarding the Class B units, refer to discussion of the ONEOK Transactions in Note B of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Purchase and Sale of General Partner Interest - In April 2006, ONEOK acquired ONEOK NB, formerly known as Northwest Border Pipeline Company, an affiliate of TransCanada that held a 0.35 percent general partner interest in us. As a result, ONEOK now owns our entire 2 percent general partner interest and controls us.

Disposition of 20 Percent Partnership Interest in Northern Border Pipeline - In April 2006, we completed the sale of a 20 percent partnership interest in Northern Border Pipeline to TC PipeLines for approximately $297 million to help finance the acquisition of the ONEOK Energy Assets. We recorded a gain on the sale of approximately $113.9 million in the second quarter of 2006. We and TC PipeLines each now own a 50 percent interest in Northern Border Pipeline, and an affiliate of TransCanada became the operator of the pipeline in April 2007. Effective January 1, 2006, our interest in Northern Border Pipeline is accounted for as an investment under the equity method in our Natural Gas Pipelines segment.

Acquisition of Guardian Pipeline Interests - In April 2006, we acquired the 66- 2/3 percent interest in Guardian Pipeline not previously owned by us for approximately $77 million, increasing our ownership interest to 100 percent. We used borrowings from our credit facility to fund the acquisition of the additional interest in Guardian Pipeline. Guardian Pipeline is consolidated in our consolidated financial statements and reported in our Natural Gas Pipelines segment as of January 1, 2006.

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Capital Projects

Woodford Shale Natural Gas Liquids Pipeline Extension - In February 2008, we announced plans to construct a 78-mile natural gas liquids gathering pipeline to connect two natural gas processing plants in the Woodford Shale area in southeast Oklahoma at a cost of approximately $25 million, excluding AFUDC. The project is currently scheduled for completion in the second quarter of 2008. These two plants are expected to produce approximately 25 MBbl/d of unfractionated NGLs. Until the Arbuckle Pipeline project is completed, the natural gas liquids production will be transported by our existing Mid-Continent natural gas liquids pipelines. Upon completion of the Arbuckle Pipeline project, the Woodford Shale natural gas liquids production is expected to be transported to our Mont Belvieu, Texas, fractionation facility. This project will be in our Natural Gas Liquids Gathering and Fractionation segment.

Overland Pass Pipeline Company - In May 2006, we entered into an agreement with a subsidiary of Williams to form a joint venture called Overland Pass Pipeline Company. Overland Pass Pipeline Company is building a 760-mile natural gas liquids pipeline from Opal, Wyoming, to the Mid-Continent natural gas liquids market center in Conway, Kansas. The pipeline is designed to transport approximately 110 MBbl/d of unfractionated NGLs, which can be increased to approximately 150 MBbl/d with additional pump facilities. During 2006, we paid $11.6 million to Williams for the acquisition of our interest in the joint venture and for reimbursement of initial capital expenditures. As the 99 percent owner of the joint venture, we will manage the construction project, advance all costs associated with construction and operate the pipeline. Within two years of the pipeline becoming operational, Williams will have the option to increase its ownership up to 50 percent by reimbursing us for its proportionate share of all construction costs. If Williams exercises its option to increase its ownership to the full 50 percent, Williams would have the option to become operator. This project has received the required approvals of various state and federal regulatory authorities, and we are constructing the pipeline with start-up currently scheduled for the second quarter of 2008.

As part of a long-term agreement, Williams dedicated its NGL production from two of its natural gas processing plants in Wyoming to the joint-venture company. We will provide downstream fractionation, storage and transportation services to Williams. The pipeline project is currently estimated to cost approximately $535 million, excluding AFUDC. Since our initial estimate in early 2006, there has been a significant increase in the demand for pipeline construction-related services, which has led to higher rates, particularly for construction labor and equipment. Additionally, due to the extended permitting process, we are constructing the pipeline during the winter months, which could contribute to added construction costs and could cause further delays. The severity of the winter conditions could further impact our cost and schedule estimates. In addition, we are investing approximately $216 million, excluding AFUDC, to expand our existing fractionation and storage capabilities and the capacity of our natural gas liquids distribution pipelines. Financing for both projects may include a combination of short- or long-term debt or equity. Overland Pass Pipeline Company is included in our Natural Gas Liquids Pipelines segment, while the associated expansions are included in our Natural Gas Liquids Gathering and Fractionation segment and Natural Gas Liquids Pipelines segment.

Piceance Lateral Pipeline - In March 2007, we announced that Overland Pass Pipeline Company also plans to construct a 150-mile lateral pipeline with capacity to transport as much as 100 MBbl/d of unfractionated NGLs from the Piceance Basin in Colorado to the Overland Pass Pipeline. Williams announced that it intends to construct a new natural gas processing plant in the Piceance Basin and will dedicate its NGL production from that plant and an existing plant to be transported by the lateral pipeline. This project requires the approval of various state and federal regulatory authorities. Assuming Overland Pass Pipeline Company obtains the required state and federal regulatory approvals, construction of this lateral pipeline is currently expected to begin in late 2008 and be completed during the second quarter of 2009, at a current cost estimate of approximately $120 million, excluding AFUDC. This project is in our Natural Gas Liquids Pipelines segment.

Arbuckle Pipeline Natural Gas Liquids Pipeline - In March 2007, we announced plans to build the 440-mile Arbuckle Pipeline, a natural gas liquids pipeline from southern Oklahoma through northern Texas and continuing on to the Texas Gulf Coast, at a current estimated cost of approximately $260 million, excluding AFUDC. The Arbuckle Pipeline will have the capacity to transport 160 MBbl/d of unfractionated natural gas liquids and will connect our existing Mid-Continent infrastructure with our fractionation facility in Mont Belvieu, Texas, and other Gulf Coast region fractionators. Construction of the pipeline will require permits from various federal, state and local regulatory bodies. Construction is currently expected to begin in mid-2008 and be completed by early 2009. This project is in our Natural Gas Liquids Pipelines segment.

Williston Basin Gas Processing Plant Expansion - In March 2007, we announced the expansion of our Grasslands natural gas processing facility in North Dakota at a cost of approximately $30 million, excluding AFUDC. The Grasslands facility is our largest natural gas processing plant in the Williston Basin. The expansion increases processing capacity to approximately 100 MMcf/d from its current capacity of 63 MMcf/d and increases fractionation capacity to approximately 12 MBbl/d from 8

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MBbl/d. The expansion project is expected to come on-line in phases, with the final phase currently expected to be on-line in the third quarter of 2008. This project is in our Natural Gas Gathering and Processing segment.

Fort Union Gas Gathering Expansion - In January 2007, Fort Union Gas Gathering announced that it will double its existing gathering pipeline capacity by adding 148 miles of new gathering lines, resulting in approximately 649 MMcf/d of additional capacity in the Powder River basin of Wyoming. The expansion is expected to cost approximately $110 million, excluding AFUDC, which will be financed within the Fort Union Gas Gathering partnership and will occur in two phases. Phase 1, with more than 200 MMcf/d capacity, was placed in service during the fourth quarter of 2007. Phase 2, with approximately 450 MMcf/d capacity, is currently expected to be in service during the second quarter of 2008. The additional capacity has been fully subscribed for 10 years beginning with the in-service date of the expansion. We own approximately 37 percent of Fort Union Gas Gathering. This investment is in our Natural Gas Gathering and Processing segment and is accounted for under the equity method of accounting.

Guardian Pipeline Expansion and Extension - In December 2007, Guardian Pipeline received and accepted the certificate of public convenience and necessity issued by the FERC for its expansion and extension project. The certificate authorizes us to construct, install and operate approximately 119 miles of a 20-inch and 30-inch natural gas transportation pipeline with a capacity to transport 537 MMcf/d of natural gas north from Ixonia, Wisconsin, to the Green Bay, Wisconsin, area. The project is supported by long-term shipper commitments. The cost of the project is currently estimated to be $260 million, excluding AFUDC. The pipeline is currently projected to be in service in the fourth quarter of 2008. This project is in our Natural Gas Pipelines segment.

Midwestern Gas Transmission Eastern Extension - Midwestern Gas Transmission’s eastern extension pipeline was placed into service in January 2008. The extension added approximately 31 miles of natural gas transportation pipeline, with a capacity to transport 120 MMcf/d of natural gas from Midwestern’s previous terminus at Portland, Tennessee, to interconnects with Columbia Gulf Transmission Company and East Tennessee Natural Gas, LLC, near Hartsville, Tennessee. The project is supported by a long-term shipper commitment. Total capital expenditures are expected to be $62 million, excluding AFUDC. This project is in our Natural Gas Pipelines segment.

IMPACT OF NEW ACCOUNTING STANDARDS

Information about the impact of Statement 157, "Fair Value Measurements," Statement 159, "The Fair Value Option for Financial Assets and Financial Liabilities," FIN 48, "Accounting for Uncertainty in Income Taxes - An Interpretation of FASB Statement No. 109," Statement 141R, "Business Combinations," and Statement 160, "Noncontrolling Interest in Consolidated Financial Statements - an amendment to ARB No. 51," is included in Note A of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of our consolidated financial statements and related disclosures in accordance with GAAP requires us to make estimates and assumptions with respect to values or conditions that cannot be known with certainty that affect the reported amount of assets and liabilities, and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements. These estimates and assumptions also affect the reported amounts of revenue and expenses during the reporting period. Although we believe these estimates are reasonable, actual results could differ from our estimates.

The following is a summary of our most critical accounting policies, which are defined as those policies most important to the portrayal of our financial condition and results of operations and requiring management’s most difficult, subjective or complex judgment, particularly because of the need to make estimates concerning the impact of inherently uncertain matters. We have discussed the development and selection of our critical accounting policies and estimates with the Audit Committee of our Board of Directors.

Impairment of Long-Lived Assets, Goodwill and Intangible Assets - We assess our long-lived assets for impairment based on Statement 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." A long-lived asset is tested for impairment whenever events or changes in circumstances indicate that its carrying amount may exceed its fair value. Fair values are based on the sum of the undiscounted future cash flows expected to result from the use and eventual disposition of the assets.

We assess our goodwill and intangible assets for impairment at least annually, based on Statement 142, "Goodwill and Other Intangible Assets." There were no impairment charges resulting from the July 1, 2007, impairment tests and no events indicating an impairment have occurred subsequent to that date. An initial assessment is made by comparing the fair value of

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the operations with goodwill, as determined in accordance with Statement 142, to the book value of each reporting unit. If the fair value is less than the book value, an impairment is indicated, and we must perform a second test to measure the amount of the impairment. In the second test, we calculate the implied fair value of the goodwill by deducting the fair value of all tangible and intangible net assets of the operations with goodwill from the fair value determined in step one of the assessment. If the carrying value of the goodwill exceeds this calculated implied fair value of the goodwill, we will record an impairment charge. At December 31, 2007, we had $394.6 million of goodwill recorded on our Consolidated Balance Sheet as shown below.

	(Thousands of dollars)
Natural Gas Gathering and Processing	$ **90,037**
Natural Gas Pipelines	**128,997**
Natural Gas Liquids Gathering and Fractionation	**175,566**
Total goodwill	$ **394,600**

Intangible assets with a finite useful life are amortized over their estimated useful life, while intangible assets with an indefinite useful life are not amortized. All intangible assets are subject to impairment testing. As shown below, we had $287.5 million of intangible assets recorded on our Consolidated Balance Sheet as of December 31, 2007.

	(Thousands of dollars)
Natural Gas Liquids Gathering and Fractionation	$ **273,751**
Natural Gas Liquids Pipelines	**13,733**
Total intangible assets	$ **287,484**

During 2006, we reassessed our coal slurry pipeline operation and concluded that the likelihood of Black Mesa resuming operations was significantly reduced, and a goodwill and asset impairment of $8.4 million and $3.6 million, respectively, was recorded as depreciation and amortization. The reduction to our net income after income taxes was $10.6 million. Additional information about Black Mesa is included above in Item 1 under "Description of Business Segments - Other."

Our total unamortized excess cost over underlying fair value of net assets accounted for under the equity method was $185.6 million as of December 31, 2007 and 2006. These amounts were recorded in investment in unconsolidated affiliates on our accompanying Consolidated Balance Sheets. For the investments we account for under the equity method, the premium or excess cost over underlying fair value of net assets is referred to as equity method goodwill and under Statement 142 is not subject to amortization but rather to impairment testing pursuant to APB Opinion No. 18, "The Equity Method of Accounting for Investments in Common Stock." The impairment test under APB Opinion No. 18 considers whether the fair value of the equity investment as a whole, not the underlying net assets, has declined and whether that decline is other than temporary. Therefore, we periodically reevaluate the amount at which we carry the excess of cost over fair value of net assets accounted for under the equity method to determine whether current events or circumstances warrant adjustments to our carrying value in accordance with APB Opinion No. 18. See Note K of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for additional discussion of unconsolidated affiliates.

We do not currently anticipate any additional goodwill or asset impairments to occur within the next year, but if such events were to occur over the long term, the impact could be significant to our financial condition and results of operations.

Derivatives and Risk Management - We utilize financial instruments to reduce our market risk exposure to interest rate and commodity price fluctuations and achieve more predictable cash flows. We account for derivative instruments utilized in connection with these activities and services under the fair value basis of accounting in accordance with Statement 133, "Accounting for Derivative Instruments and Hedging Activities," as amended.

Under Statement 133, entities are required to record derivative instruments at fair value. The fair value of a derivative instrument is determined by commodity exchange prices, over-the-counter quotes, volatility, time value, counterparty credit and the potential impact on market prices of liquidating positions in an orderly manner over a reasonable period of time under current market conditions.

Market value changes result in a change in the fair value of our derivative instruments. The accounting for changes in the fair value of a derivative instrument depends on whether it has been designated and qualifies as part of a hedging relationship and, if so, the nature of the risk being hedged and how we will determine if the hedging instrument is effective. If the derivative instrument does not qualify or is not designated as part of a hedging relationship, then we account for changes in fair value of the derivative in earnings as they occur. Commodity price volatility may have a significant impact on the gain

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or loss in a given period. For more information on fair value sensitivity and a discussion of the market risk of pricing changes, see Item 7A, Quantitative and Qualitative Disclosures about Market Risk.

To minimize the risk of fluctuations in natural gas, NGLs and condensate prices, we periodically enter into futures, collars or swap transactions in order to hedge anticipated purchases and sales of natural gas, NGLs, condensate, and fuel requirements. Interest rate swaps are also used to manage interest rate risk. Under certain conditions, we designate these derivative instruments as a hedge of exposure to changes in fair values or cash flow. For hedges of exposure to changes in cash flow, the effective portion of the gain or loss on the derivative instrument is reported initially as a component of accumulated other comprehensive income (loss) and subsequently recorded to earnings when the forecasted transaction affects earnings. Any ineffectiveness of designated hedges is reported in earnings in the period the ineffectiveness occurs. For hedges of exposure to changes in fair value, the gain or loss on the derivative instrument is recognized in earnings during the period of change together with the offsetting gain or loss on the hedged item attributable to the risk being hedged.

Upon election, many of our purchase and sale agreements that otherwise would be required to follow derivative accounting qualify as normal purchases and normal sales under Statement 133 and are therefore exempt from fair value accounting treatment.

See Note C of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for more discussion of derivatives and risk management activities.

Contingencies - Our accounting for contingencies covers a variety of business activities, including contingencies for legal and environmental exposures. We accrue these contingencies when our assessments indicate that it is probable that a liability has been incurred or an asset will not be recovered and an amount can be reasonably estimated in accordance with Statement 5, "Accounting for Contingencies." We base our estimates on currently available facts and our estimates of the ultimate outcome or resolution. Actual results may differ from our estimates resulting in an impact, positive or negative, on earnings. See Note H of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for additional discussion of contingencies.

FINANCIAL AND OPERATING RESULTS

Consolidated Operations

Selected Financial Information - The following table sets forth certain selected financial information for the periods indicated.

	Years Ended December 31,		
Financial Results	**2007**	**2006**	**2005**
	(Thousands of dollars)		
Operating revenue	**$ 5,831,558**	$ 4,738,248	$ 703,944
Cost of sales and fuel	**4,935,665**	3,894,700	210,082
Net margin	**895,893**	843,548	493,862
Operating costs	**337,356**	325,774	151,084
Depreciation and amortization	**113,704**	122,045	86,010
Gain on sale of assets	**1,950**	115,483	-
Operating income	**$ 446,783**	$ 511,212	$ 256,768
Equity earnings from investments	**$ 89,908**	$ 95,883	$ 24,736
Allowance for equity funds used during construction	**$ 12,538**	$ 2,205	$ 527
Interest expense	**$ 138,947**	$ 133,482	$ 86,903
Minority interests in income of consolidated subsidiaries	**$ 416**	$ 2,392	$ 45,674

Operating Results - Net margin increased for 2007, compared with 2006, primarily due to the performance of our Natural Gas Liquids Gathering and Fractionation segment and Natural Gas Liquids Pipelines segment, which benefited primarily from new supply connections that increased volumes gathered, transported, fractionated and sold. In addition, net margin increased due to higher product price spreads and higher isomerization price spreads in our Natural Gas Liquids Gathering and Fractionation segment. Our Natural Gas Liquids Pipelines segment benefited from the incremental net margin related to the acquired assets from Kinder Morgan in October 2007. Net margin also increased due to increased storage margins in our Natural Gas Pipelines segment. These increases were partially offset by decreased natural gas transportation margins in our Natural Gas Pipelines segment, primarily resulting from lower throughput and higher fuel costs. Net margin also decreased

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in our Natural Gas Gathering and Processing segment, primarily due to lower natural gas volumes processed as a result of contract terminations in late 2006.

Operating costs increased for 2007, compared with 2006, primarily due to higher employee-related costs and the incremental operating expenses associated with our acquired assets from Kinder Morgan, partially offset by lower litigation costs.

Depreciation and amortization decreased for 2007, compared with 2006, primarily due to a goodwill and asset impairment charge of $12.0 million recorded in the second quarter of 2006 related to Black Mesa, which is included in our Other segment.

Gain on sale of assets decreased for 2007, compared with 2006, primarily due to the $113.9 million gain on sale of a 20 percent partnership interest in Northern Border Pipeline recorded in the second quarter of 2006 in our Natural Gas Pipelines segment.

Equity earnings from investments for 2007 and 2006 primarily include earnings from our interest in Northern Border Pipeline. The decrease in equity earnings from investments for 2007 is primarily due to the decrease in our share of Northern Border Pipeline's earnings from 70 percent in the first quarter of 2006 to 50 percent beginning in the second quarter of 2006. See page 32 for discussion of the disposition of the 20 percent partnership interest in Northern Border Pipeline.

Allowance for equity funds used during construction increased for 2007, compared with 2006, due to our capital projects, which are discussed beginning on page 33.

Minority interest in income of consolidated subsidiaries decreased for 2007, compared with 2006, primarily due to our acquisition of the remaining interest in Guardian Pipeline. Minority interest in income of consolidated subsidiaries for 2006 included the 66- 2/3 percent interest in Guardian Pipeline that we did not own until April 2006. We owned 100 percent of Guardian Pipeline beginning in April 2006, resulting in no minority interest in income of consolidated subsidiaries related to Guardian Pipeline after March 31, 2006.

Net margin was $843.5 million in 2006, compared with $493.9 million in 2005. Net margin increased primarily due to the acquisition of the ONEOK Energy Assets, which accounts for $638.9 million of our consolidated net margin for the period, and, to a lesser extent, the effect of the Guardian Pipeline consolidation, partially offset by the effect of the Northern Border Pipeline deconsolidation.

Operating costs increased in 2006, compared with 2005, primarily due to our acquisition of the ONEOK Energy Assets.

Equity earnings from investments for 2006 primarily consisted of earnings from our interest in Northern Border Pipeline which is no longer consolidated as of January 1, 2006. Equity earnings from investments for 2005 consisted of earnings from our 33- 1/3 percent interest in Guardian Pipeline, which is reflected on a consolidated basis beginning January 1, 2006.

Minority interest in net income for 2006 included earnings from the 66- 2/3 percent interest in Guardian Pipeline until that interest was acquired by us in April 2006. Minority interest in net income for 2005 included earnings from the 30 percent interest in Northern Border Pipeline owned by TC PipeLines when Northern Border Pipeline's results were consolidated.

More information regarding our results of operations is provided in the following discussion of operating results for each of our segments.

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Natural Gas Gathering and Processing

Acquisition - In April 2006, we completed the acquisition of the ONEOK Energy Assets, which is discussed further on page 32.

Selected Financial and Operating Information - The following tables set forth certain selected financial and operating information for our Natural Gas Gathering and Processing segment for the periods indicated.

	Years Ended December 31,		
Financial Results	**2007**	**2006**	**2005**
	(Thousands of dollars)		
Natural gas liquids and condensate sales	**$ 673,800**	$ 646,548	$ 123,088
Gas sales	**636,761**	706,318	107,999
Gathering, compression, dehydration and processing fees and other revenue	**148,089**	123,224	44,200
Cost of sales and fuel	**1,092,139**	1,105,329	180,052
Net margin	**366,511**	370,761	95,235
Operating costs	**135,422**	147,487	34,476
Depreciation and amortization	**45,099**	43,032	16,045
Gain on sale of assets	**1,825**	373	-
Operating income	**$ 187,815**	$ 180,615	$ 44,714
Equity earnings from investments	**$ 26,399**	$ 22,616	$ 22,473

	Years Ended December 31,		
Operating Information	**2007**	**2006**	**2005**
Natural gas gathered *(BBtu/d)*	**1,171**	1,168	274
Natural gas processed *(BBtu/d)*	**621**	988	94
Natural gas liquids sales *(MBbl/d)*	**38**	42	8
Natural gas sales *(BBtu/d)*	**281**	302	43
Capital expenditures *(Thousands of dollars)*	**$ 83,820**	$ 80,982	$ 16,602
Realized composite NGL sales price *($/gallon)*	**$ 1.06**	$ 0.93	$ 0.92
Realized condensate sales price *($/Bbl)*	**$ 67.35**	$ 57.84	$ -
Realized natural gas sales price *($/MMBtu)*	**$ 6.21**	$ 6.31	$ 6.87
Realized gross processing spread *($/MMBtu)*	**$ 5.21**	$ 5.05	$ -

	Years Ended December 31,		
	2007	**2006**	**2005**
Percent of proceeds			
Wellhead purchases *(MMBtu/d)*	**83,993**	121,199	-
NGL sales *(Bbl/d)*	**5,959**	7,364	2,376
Residue sales *(MMBtu/d)*	**34,010**	28,855	12,502
Condensate sales *(Bbl/d)*	**719**	1,103	-
Percentage of total net margin	**56%**	55%	57%
Fee-based			
Wellhead volumes *(MMBtu/d)*	**1,170,502**	1,168,478	274,359
Average rate *($/MMBtu)*	**$ 0.25**	$ 0.25	$ 0.41
Percentage of total net margin	**30%**	29%	43%
Keep-whole			
NGL shrink *(MMBtu/d)*	**23,636**	37,029	-
Plant fuel *(MMBtu/d)*	**2,846**	4,959	-
Condensate shrink *(MMBtu/d)*	**2,490**	3,328	-
Condensate sales *(Bbl/d)*	**504**	683	-
Percentage of total net margin	**14%**	16%	0%

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Operating Results - Net margin decreased $4.3 million for 2007, compared with 2006, primarily due to the following:

- a decrease of $25.8 million from lower volumes processed as a result of contract terminations at the Bushton Plant in late 2006,
- a decrease of $5.6 million primarily due to lower processed volumes associated with winter storms and summer flooding in the Mid-Continent region and reduced processing capacity due to a temporary shutdown to install additional processing and fractionation capacity at our Grasslands plant located in the Williston Basin, partially offset by
- an increase of $13.0 million in fee margins primarily from improved contractual terms and increased volumes in our gathering business,
- an increase of $8.6 million due to one-time favorable contract settlements that occurred in the fourth quarter of 2007, and
- an increase of $5.5 million due to higher realized natural gas liquids and natural gas prices.

Operating costs decreased $12.1 million for 2007, compared with 2006, primarily due to lower litigation costs and reduced operating expenses associated with the temporarily idled Bushton Plant, partially offset by higher employee-related costs.

Depreciation and amortization and capital expenditures increased for 2007, compared with 2006, primarily due to increased depreciation expense associated with our capital projects, which are discussed beginning on page 33.

The increase in equity earnings from investments for 2007, compared with 2006, is driven primarily by the earnings related to our interest in an investment in Venice Energy Services Co., LLC which operated on a limited basis in 2006 due to hurricane damage.

Net margin increased $275.5 million in 2006, compared with 2005, primarily due to the following:

- an increase of $263.1 million related to the acquisition of ONEOK’s natural gas gathering and processing assets,
- an increase of $3.2 million resulting from favorable commodity pricing for natural gas and NGL products on POP contracts in the Rocky Mountain region, net of hedging, and
- an increase of $9.0 million resulting from increased natural gas volumes gathered and processed in the Rocky Mountain region, partially offset by lower average gathering rates.

Our Natural Gas Gathering and Processing segment is exposed to commodity price risk, primarily from NGLs, as a result of our contractual obligations for services provided. A small percentage of our services are provided through keep-whole arrangements. Our realized gross processing spread for 2007 was above the five-year average of $3.58 per MMBtu. See discussion regarding our commodity price risk beginning on page 51 under "Commodity Price Risk" in Item 7A, Quantitative and Qualitative Disclosures about Market Risk.

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Natural Gas Pipelines

Acquisition and Divestiture - The following transactions are described beginning on page 32.

- In April 2006, we completed the acquisition of the ONEOK Energy Assets, which is discussed further on page 32.
- In April 2006, we completed the sale of a 20 percent partnership interest in Northern Border Pipeline to TC PipeLines. We and TC PipeLines each now own a 50 percent interest in Northern Border Pipeline, and an affiliate of TransCanada became operator of the pipeline in April 2007.
- In April 2006, we acquired the 66- 2/3 percent interest in Guardian Pipeline not previously owned by us for approximately $77 million, increasing our ownership interest to 100 percent.

Selected Financial and Operating Information - The following tables set forth certain selected financial and operating results for our Natural Gas Pipelines segment for the periods indicated.

	Years Ended December 31,		
Financial Results	**2007**	**2006**	**2005**
	(Thousands of dollars)		
Transportation revenue	**$228,173**	$234,187	$395,670
Storage revenue	**54,809**	49,486	-
Gas sales and other revenue	**18,982**	33,335	8,415
Cost of sales	**60,867**	70,211	30,030
Net margin	**241,097**	246,797	374,055
Operating costs	**96,584**	91,516	92,630
Depreciation and amortization	**32,380**	32,841	67,257
Gain on sale of assets	**79**	114,890	-
Operating income	**$112,212**	$237,330	$214,168
Equity earnings from investments	**$ 62,487**	$ 72,835	$ 2,263
Allowance for equity funds used during construction	**$ 3,670**	$ 918	$ 527
Minority interest in income of consolidated subsidiaries	**$ 387**	$ 2,392	$ 45,674

	Years Ended December 31,		
Operating Information (a)	**2007**	**2006**	**2005**
Natural gas transported *(MMcf/d)*	**3,579**	3,634	3,808
Average natural gas price			
Mid-continent region (*$/MMBtu*)	**$ 6.05**	$ 6.04	(b)
Capital expenditures *(Thousands of dollars)*	**$138,919**	$ 48,598	$ 39,641

(a) Includes volumes for consolidated entities only.
(b) Companies in the Mid-Continent region were acquired as part of the ONEOK Transactions effective January 1, 2006.

Operating Results - Net margin decreased $5.7 million for 2007, compared with 2006, due to the following:

- a decrease of $7.1 million from natural gas transportation margins, as a result of lower throughput and higher fuel costs,
- a decrease of $2.8 million primarily due to the expiration of reimbursements associated with an intrastate natural gas transportation construction project in Oklahoma, and
- a decrease of $0.9 million due to a reduction in operational natural gas inventory sales, partially offset by
- an increase of $5.4 million from natural gas storage margins as a result of new and renegotiated contracts.

Operating costs increased $5.1 million for 2007, compared with 2006, primarily due to higher employee-related costs.

Equity earnings from investments for 2007 and 2006 primarily include earnings from our interest in Northern Border Pipeline. The decrease in equity earnings from investments of $10.3 million for 2007, compared with 2006, is primarily due to the decrease in our share of Northern Border Pipeline's earnings from 70 percent in the first quarter of 2006 to 50 percent beginning in the second quarter of 2006. See page 32 for discussion of the disposition of the 20 percent partnership interest in Northern Border Pipeline.

The increase in capital expenditures for 2007, compared with 2006, is driven primarily by our capital projects, which are discussed beginning on page 33.

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Net margin decreased $127.3 million for 2006, compared with 2005, due to the following:

- a decrease of $321.7 million related to Northern Border Pipeline, which is no longer consolidated as of January 1, 2006, offset by
- an increase of $149.7 million due to acquisition of the pipelines and storage assets from ONEOK,
- an increase of $35.6 million due to the consolidation of Guardian Pipeline,
- an increase of $7.7 million from natural transportation revenues as a result of lower fuel costs and higher throughput, and
- an increase of $1.7 million due to the acquisition of OkTex Pipeline from ONEOK.

Depreciation and amortization decreased $34.4 million for 2006, compared with 2005, due to a decrease of $58.1 million related to Northern Border Pipeline, which is no longer consolidated as of January 1, 2006, offset by an increase of $5.9 million due to the consolidation of Guardian Pipeline and $17.8 million due to acquiring assets from ONEOK.

During the second quarter of 2006, we sold a 20 percent partnership interest in Northern Border Pipeline and recorded a gain on sale of approximately $113.9 million.

The increase in equity earnings from investments of $70.6 million for 2006, compared with 2005, is primarily due to our interest in Northern Border Pipeline, which is no longer consolidated as of January 1, 2006. Equity earnings from investments of $2.3 million for 2005 were primarily due to our 33-1/3 percent interest in Guardian Pipeline, which is reflected on a consolidated basis beginning January 1, 2006.

Minority interest in income of consolidated subsidiaries for 2006 included the 66-2/3 percent interest in Guardian Pipeline until that interest was acquired by us in April 2006. Minority interest in net income for 2005 included earnings from the 30 percent interest in Northern Border Pipeline owned by TC PipeLines when Northern Border Pipeline's results were consolidated.

The increase in capital expenditures for 2006, compared with 2005, is primarily due to the assets acquired from ONEOK.

Natural Gas Liquids Gathering and Fractionation

Acquisition - In April 2006, we completed the acquisition of the ONEOK Energy Assets, which is discussed further on page 32. We did not have a Natural Gas Liquids Gathering and Fractionation segment prior to 2006.

Selected Financial and Operating Information - The following tables set forth certain selected financial and operating results for our Natural Gas Liquids Gathering and Fractionation segment for the periods indicated.

	Years Ended December 31,	
Financial Results	**2007**	**2006**
	(Thousands of dollars)	
Natural gas liquids and condensate sales	**$ 4,310,474**	$ 3,295,462
Storage and fractionation revenue	**276,819**	197,514
Cost of sales and fuel	**4,381,529**	3,325,995
Net margin	**205,764**	166,981
Operating costs	**70,693**	57,511
Depreciation and amortization	**23,134**	20,738
Gain on sale of assets	**39**	47
Operating income	**$ 111,976**	$ 88,779

	Years Ended December 31,	
Operating Information	**2007**	**2006**
Natural gas liquids gathered *(MBbl/d)*	**228**	206
Natural gas liquids sales *(MBbl/d)*	**231**	207
Natural gas liquids fractionated *(MBbl/d)*	**356**	313
Conway-to-Mont Belvieu OPIS average spread		
Ethane/Propane mixture *($/gallon)*	**$ 0.06**	$ 0.05
Capital expenditures *(Thousands of dollars)*	**$ 123,555**	$ 21,761

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Operating Results - Net margin increased $38.8 million for 2007, compared with 2006, due to the following:
- an increase of $17.8 million due to higher exchange net margin primarily driven by increased volumes due to new supply connections, improved natural gas processing economics and increased fractionation volumes at our Mont Belvieu fractionator,
- an increase of $13.5 million due to higher product price spreads and higher isomerization price spreads, and
- an increase of $7.6 million due to new storage contracts entered into in the second quarter of 2007 and our acquisition of the Mont Belvieu storage assets in the fourth quarter of 2006.

Operating costs increased for 2007, compared with 2006, primarily due to higher regulatory compliance costs at our storage facilities, employee-related costs and general taxes, as well as the acquisition of the Mont Belvieu storage assets in the fourth quarter of 2006.

The increase in capital expenditures for 2007, compared with 2006, is driven primarily by our growth activities for new supply connections. See discussion of our capital projects beginning on page 33.

Natural Gas Liquids Pipelines

Acquisitions - The following acquisitions are described beginning on page 32.
- In October 2007, we completed the acquisition of an interstate natural gas liquids and refined petroleum products pipeline system and related assets from a subsidiary of Kinder Morgan for approximately $300 million, before working capital adjustments. The system extends from Bushton and Conway, Kansas, to Chicago, Illinois, and transports, stores and delivers a full range of NGL and refined products. The FERC-regulated system spans approximately 1,627 miles and has a capacity to transport up to 134 MBbl/d. The transaction includes approximately 978 MBbl of owned storage capacity, eight NGL terminals and a 50 percent ownership of Heartland.
- In April 2006, we completed the acquisition of the ONEOK Energy Assets, which is discussed further on page 32. We did not have a Natural Gas Liquids Pipelines segment prior to 2006.

Selected Financial and Operating Information - The following tables set forth certain selected financial and operating results for our Natural Gas Liquids Pipelines segment for the periods indicated.

	Years Ended December 31,	
Financial Results	**2007**	**2006**
	(Thousands of dollars)	
Transportation and gathering revenue	**$ 90,441**	$ 66,433
Storage revenue	**768**	-
Gas sales and other revenue	**626**	63
Cost of sales and fuel	**10,363**	6,049
Net margin	**81,472**	60,447
Operating costs	**28,957**	19,333
Depreciation and amortization	**13,062**	12,035
Gain on sale of assets	**7**	7
Operating income	**$ 39,460**	$ 29,086
Equity earnings from investments	**$ 1,022**	$ 432
Allowance for equity funds used during construction	**$ 8,868**	$ 1,287
Minority interest in income of consolidated subsidiaries	**$ 29**	$ -

	Years Ended December 31,	
Operating Information	**2007**	**2006**
Natural gas liquids transported *(MBbl/d)*	**299**	200
Natural gas liquids gathered *(MBbl/d)*	**81**	60
Capital expenditures *(Thousands of dollars)*	**$ 363,460**	$ 49,322

Operating Results - Net margin increased $21.0 million for 2007, compared with 2006, primarily as a result of:
- an increase of $11.5 million due to incremental margin from our acquired assets from Kinder Morgan in October 2007 and
- an increase of $9.5 million primarily due to increased throughput from new supply connections and increased production volume from existing supply connections to our natural gas liquids gathering pipelines.

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Operating costs increased $9.6 million for 2007, compared with 2006, primarily due to $5.8 million in incremental operating expenses associated with our acquired assets from Kinder Morgan, as well as higher employee-related costs.

Depreciation and amortization increased for 2007, compared with 2006, primarily due to incremental operating expenses associated with our acquired assets from Kinder Morgan.

The increase in capital expenditures for 2007, compared with 2006, is driven primarily by our growth activities. See discussion of our capital projects beginning on page 33.

Other

In 2007, we recorded a net loss of $1.6 million to maintain the standby status of the Black Mesa facility. We recorded a loss on Black Mesa for 2006 of $12.0 million, which included an after-tax reduction to net income of $10.6 million for the goodwill and asset impairments recognized during the year, compared with net income in 2005 of $3.9 million. We expect that maintaining standby status of the Black Mesa facilities would result in a loss in 2008 of approximately $1.6 million if we do not divest or decommission the pipeline. We plan to either divest the Black Mesa pipeline or commence decommissioning of the pipeline during 2008.

Contingencies

Legal Proceedings - We are a party to various litigation matters and claims that are in the normal course of our operations. While the results of litigation and claims cannot be predicted with certainty, we believe the final outcome of such matters will not have a material adverse effect on our consolidated results of operations, financial position or liquidity.

Other - As a result of an internal review of a transaction that was brought to the attention of one of our affiliates by a third party, we have commenced an internal review of transactions that may have violated FERC capacity release rules or related rules. We have notified the FERC of this review and expect to file a report with the FERC by mid-March 2008 concerning any violations. At this time, we do not believe that penalties, if any, associated with potential violations will have a material impact on our results of operations, financial position or liquidity.

LIQUIDITY AND CAPITAL RESOURCES

General - Our principal sources of liquidity include cash generated from operating activities, bank credit facilities, debt issuances and the sale of limited partner units. We fund our operating expenses, debt service and cash distributions to our limited and general partners primarily with operating cash flow.

Part of our growth strategy is to expand our existing businesses and strategically acquire related businesses that strengthen and complement our existing assets. Capital resources for acquisitions and maintenance and growth expenditures may be funded by a variety of sources, including those listed above as our principal sources of liquidity. Beginning in 2007 and continuing in 2008, the capital markets have been impacted by macroeconomic, liquidity and other recessionary concerns. During this period, we have continued to have access to our 2007 Partnership Credit Agreement to fund our short-term liquidity needs, and we issued $600 million of long-term debt. Our ability to continue to access capital markets for debt and equity financing under reasonable terms depends on our financial condition, credit ratings and market conditions. We anticipate that our existing capital resources, ability to obtain financing and cash flow generated from future operations will enable us to maintain our current level of operations and our planned operations including capital expenditures for the foreseeable future. Our capital expenditures for 2007 and 2006 were financed through operating cash flows and short- and long-term debt. Capital expenditures were $709.9 million and $201.7 million for 2007 and 2006, respectively, exclusive of acquisitions. The increase in capital expenditures for 2007, compared with 2006, is driven primarily by our capital projects, which are discussed beginning on page 33.

Financing - Financing is provided through available cash, our amended and restated revolving credit agreement (2007 Partnership Credit Agreement) and long-term debt. Other options to obtain financing include, but are not limited to, issuance of limited partner units, issuance of hybrid securities such as any trust preferred security or deferrable interest subordinated debt issued by us or any business trusts and sale/leaseback of facilities.

The total amount of short-term borrowings authorized by our general partner's Board of Directors is $1.5 billion. At December 31, 2007, we had $900 million of credit available to us under the 2007 Partnership Credit Agreement, $100 million in borrowings outstanding under the 2007 Partnership Credit Agreement and available cash of approximately $3.2 million.

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The Guardian Pipeline revolving credit agreement terminated in November 2007. As of December 31, 2007, we could have issued $1.1 billion of additional debt under the most restrictive provisions contained in our various borrowing agreements.

Our 2007 Partnership Credit Agreement contains typical covenants as discussed in Note F of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K. At December 31, 2007, we were in compliance with all covenants.

In November 2007, we entered into a $15 million Senior Unsecured Letter of Credit Facility and Reimbursement Agreement with Wells Fargo Bank, N.A., of which $12 million is being used, and a $12 million Standby Letter of Credit Agreement with Royal Bank of Canada. Both agreements are used to support various permits required by the KDHE for our ongoing business in Kansas.

Debt Issuance - In September 2007, we completed an underwritten public offering of $600 million aggregate principal amount of 6.85 percent Senior Notes due 2037 (the 2037 Notes). The 2037 Notes were issued under our existing shelf registration statement filed with the SEC.

In September 2006, we completed an underwritten public offering of (i) $350 million aggregate principal amount of 5.90 percent Senior Notes due 2012 (the 2012 Notes), (ii) $450 million aggregate principal amount of 6.15 percent Senior Notes due 2016 (the 2016 Notes) and (iii) $600 million aggregate principal amount of 6.65 percent Senior Notes due 2036 (the 2036 Notes and collectively with the 2012 Notes and the 2016 Notes, the Notes). We registered the sale of the Notes with the SEC pursuant to a shelf registration statement filed on September 19, 2006.

For more information regarding the 2037 Notes and the Notes, refer to the discussion in Note G of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Equity Issuance - In connection with the ONEOK Transactions, we amended our Partnership Agreement to provide for the issuance of Class B limited partner units and issued approximately 36.5 million Class B limited partner units to ONEOK. The Class B limited partner units were issued on April 6, 2006. For more information regarding the Class B units, refer to discussion of the ONEOK Transactions in Note B of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

Capitalization Structure - The following table sets forth our capitalization structure for the periods indicated.

	December 31, 2007	December 31, 2006
Long-term Debt	**54%**	48%
Equity	**46%**	52%
Debt (including notes payable)	**55%**	48%
Equity	**45%**	52%

Credit Ratings - Our investment grade credit ratings as of December 31, 2007, are shown in the table below.

Rating Agency	Rating	Outlook
Moody’s	Baa2	Stable
S&P	BBB	Stable

Our credit ratings may be affected by a material change in our financial ratios or a material event affecting our business. The most common criteria for assessment of our credit ratings are the debt-to-EBITDA ratio, interest coverage, business risk profile and liquidity. If our credit ratings were downgraded, the interest rates on the 2007 Partnership Credit Agreement borrowings would increase, resulting in an increase in our cost to borrow funds.

Our $250 million and $225 million long-term notes payable, due 2010 and 2011, respectively, contain provisions that require us to offer to repurchase the senior notes at par value if our Moody’s or S&P credit rating falls below investment grade (Baa3 for Moody’s or BBB- for S&P) and the investment grade rating is not reinstated within a period of 40 days. Further, the indentures governing our senior notes due 2010 and 2011 include an event of default upon acceleration of other indebtedness of $25 million or more and the indentures governing our senior notes due 2012, 2016, 2036 and 2037 include an event of default upon the acceleration of other indebtedness of $100 million or more that would be triggered by such an offer to repurchase. Such an event of default would entitle the trustee or the holders of 25 percent in aggregate principal amount of

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the outstanding senior notes due 2010, 2011, 2012, 2016, 2036 and 2037 to declare those notes immediately due and payable in full. We may not have sufficient cash on hand to repurchase and repay any accelerated senior notes, which may cause us to borrow money under our credit facilities or seek alternative financing sources to finance the repurchases and repayment. We could also face difficulties accessing capital or our borrowing costs could increase, impacting our ability to obtain financing for acquisitions or capital expenditures, to refinance indebtedness and to fulfill our debt obligations. A decline in our credit rating below investment grade may also require us to provide security to our counterparties in the form of cash, letters of credit or other negotiable instruments.

Other than the note repurchase obligations described above, we have determined that we do not have significant exposure to rating triggers in various other contracts and equipment leases. Rating triggers are defined as provisions that would create an automatic default or acceleration of indebtedness based on a change in our credit rating. Our credit agreements contain provisions that would cause the cost to borrow funds to increase if our credit rating is negatively adjusted. An adverse rating change is not defined as a default of our credit agreements.

Capital Expenditures - We classify expenditures that are expected to generate additional revenue or significant operating efficiencies as growth capital expenditures. Any remaining capital expenditures are classified as maintenance capital expenditures.

The following tables set forth the growth and maintenance capital expenditures for 2007, 2006 and 2005.

Growth Capital Expenditures	**2007**	**2006**	**2005**
	(Millions of dollars)		
Natural Gas Gathering and Processing	**$ 64.8**	$ 59.4	$14.3
Natural Gas Pipelines	**123.6**	28.5	16.2
Natural Gas Liquids Gathering and Fractionation	**102.4**	7.0	-
Natural Gas Liquids Pipelines	**359.5**	39.8	-
Total growth capital expenditures	**$650.3**	$134.7	$30.5

Maintenance Capital Expenditures	**2007**	**2006**	**2005**
	(Millions of dollars)		
Natural Gas Gathering and Processing	**$19.0**	$21.6	$ 2.3
Natural Gas Pipelines	**15.3**	20.1	23.4
Natural Gas Liquids Gathering and Fractionation	**21.2**	14.7	-
Natural Gas Liquids Pipelines	**4.0**	9.5	-
Other	**0.1**	1.1	3.7
Total maintenance capital expenditures	**$59.6**	$67.0	$29.4

The majority of the capital expenditures are related to the growth projects discussed in more detail beginning on page 33.

The following table summarizes our 2008 projected growth and maintenance capital expenditures, excluding AFUDC.

2008 Projected Capital Expenditures	**Growth**	**Maintenance**	**Total**
		(Millions of dollars)	
Natural Gas Gathering and Processing	**$ 79**	$ 26	$ 105
Natural Gas Pipelines	**192**	24	216
Natural Gas Liquids Gathering and Fractionation	**99**	29	128
Natural Gas Liquids Pipelines	**484**	12	496
Total projected capital expenditures	**$ 854**	$ 91	$ 945

Additional information about these projects is included under "Capital Projects" on page 33. Financing for these projects may include any, or a combination of, the following: cash from operations, borrowings under the 2007 Partnership Credit Agreement, and debt or equity offerings.

Cash Distributions - We distribute 100 percent of our available cash, which generally consists of all cash receipts less adjustments for cash disbursements and net change to reserves, to our general and limited partners. Our income is allocated to our general partner and limited partners according to their partnership percentages of 2 percent and 98 percent, respectively. The effect of any incremental income allocations for incentive distributions to our general partner is calculated

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after the income allocation for the general partner's partnership interest and before the income allocation to the limited partners.

The following table sets forth the distribution payments for the common and Class B unitholders and our general partner for their general partner and incentive distribution interests for the periods indicated.

	Years Ended December 31, 2007	2006	2005
	(Millions of dollars)		
Common unitholders	**$ 184.7**	$ 167.0	$ 148.5
Class B unitholders	**145.2**	70.1	-
General Partner	**54.7**	28.4	11.1

The following summarizes our quarterly cash distribution activity for 2007:

- In January 2007, we increased our cash distribution to $0.98 per unit for the fourth quarter of 2006. The distribution was paid on February 14, 2007, to unitholders of record on January 31, 2007.
- In April 2007, we increased our cash distribution to $0.99 per unit for the first quarter of 2007. The distribution was paid on May 14, 2007, to unitholders of record as of April 30, 2007.
- In July 2007, we increased our cash distribution to $1.00 per unit for the second quarter of 2007. The distribution was paid on August 14, 2007, to unitholders of record on July 31, 2007.
- In October 2007, we increased our cash distribution to $1.01 per unit for the third quarter of 2007. The distribution was paid on November 14, 2007, to unitholders of record on October 31, 2007.

In January 2008, we increased our cash distribution to $1.025 per unit ($4.10 on an annualized basis) for the fourth quarter of 2007. The distribution was paid on February 14, 2008, to unitholders of record on January 31, 2008.

Additional information about our cash distributions is included under Item 5, Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities, and Item 13, Certain Relationships and Related Transactions and Director Independence.

ENVIRONMENTAL LIABILITIES

Information about our environmental liabilities is included in Note H of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

CASH FLOW ANALYSIS

Operating Cash Flows - Operating cash flows increased by $98.3 million for 2007, compared with 2006, primarily as a result of changes in the components of working capital. These changes increased operating cash flows by $180.3 million, compared with an increase of $123.7 million for 2006, primarily due to increases in accounts payable, partially offset by increases in accounts receivable. Operating cash flows also increased due to a decrease in income taxes as a result of our consolidation of the ONEOK Energy Assets, as of January 1, 2006, which were previously owned by a taxable entity.

Operating cash flows increased by $335.8 million for 2006 compared with 2005. The increase in operating cash flows was primarily the result of the acquisition of the ONEOK Energy Assets. Changes in components of working capital, net of the effect of the acquisition, increased operating cash flow by $123.7 million, compared with a decrease of $2.9 million in 2005, primarily as a result of decreases in accounts receivable, decreases in inventories and increases in accrued interest.

Investing Cash Flows - Cash used in investing activities was $1.0 billion for 2007, compared with $1.3 billion for 2006. Cash used in investing activities was $68.4 million for 2005.

Investing cash flows for 2007 included the following:

- the acquisition of an interstate natural gas liquids and refined petroleum products pipeline system and related assets from a subsidiary of Kinder Morgan in October 2007 for approximately $300 million, before working capital adjustments, and
- increased capital expenditures of $508.1 million in 2007, compared with 2006, due to our capital projects. See page 33 for discussion of our capital projects.

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Investing cash flows for 2006 included the following:

- the April 2006 purchase of the ONEOK Energy Assets, which included a cash payment of approximately $1.35 billion, before adjustments,
- the acquisition of the 66-2/3 percent interest in Guardian Pipeline not previously owned by us for approximately $77 million,
- payment to Williams of $11.6 million for initial capital expenditures in connection with the Overland Pass Pipeline Company natural gas liquids pipeline joint venture,
- an equity contribution to Northern Border Pipeline of $7.2 million,
- the receipt of approximately $297 million from the sale of a 20 percent partnership interest in Northern Border Pipeline to TC PipeLines,
- increased capital expenditures of $141.9 million in 2006, compared with 2005, primarily related to the ONEOK Energy Assets, and
- the impact of the deconsolidation of Northern Border Pipeline and the consolidation of the ONEOK Energy Assets and Guardian Pipeline.

During 2007 and 2006, we used borrowings from our 2007 Partnership Credit Agreement and cash provided by operating activities to fund our investing activities. During 2006, we also used our Bridge Facility. These borrowings were subsequently repaid with proceeds from the public offering of senior notes completed in the third quarters of 2007 and 2006.

Financing Cash Flows - Cash provided by financing activities was $289.7 million for 2007, compared with $696.9 million for 2006. Cash used in financing activities was $189.8 million for 2005.

During the third quarter of 2007, we completed an underwritten public offering of senior notes totaling $598 million in net proceeds, before offering expenses. During the third quarter of 2006, we completed the underwritten public offering of senior notes totaling $1.4 billion in net proceeds, before offering expenses. The use of these proceeds is discussed below.

We had net borrowings of approximately $94.0 million in 2007, compared with net payments of $200.5 million in 2006. The changes occurred for the following reasons:

- During 2007, short-term financing was primarily used to fund our capital projects. The $598 million debt issuance, net of discounts, was used to repay borrowings under the 2007 Partnership Credit Agreement and finance the $300 million acquisition of assets, before working capital adjustments, from a subsidiary of Kinder Morgan in October 2007.
- During the second quarter of 2006, we borrowed $1.05 billion under our Bridge Facility to finance a portion of the acquisition of the ONEOK Energy Assets and $77 million under our revolving credit agreement to acquire the 66-2/3 percent interest in Guardian Pipeline. In the third quarter of 2006, the net proceeds from the senior notes issued in 2006 discussed above were used to repay all of the amounts outstanding under our Bridge Facility and to repay $335 million of short-term debt.

In 2005, borrowings under Northern Border Pipeline's and our revolving credit agreements were primarily used to repay amounts borrowed under previously existing credit agreements for Northern Border Pipeline and us. Total borrowings in 2005 were $165.0 million and debt repayments were $130.2 million. We also paid $2.8 million to terminate forward-starting interest rate swaps.

We reported cash flows retained by ONEOK of $177.5 million in 2006, which represented the cash flows generated during the first quarter of 2006 by the ONEOK Energy Assets prior to the ONEOK Transactions.

In March 2006, we borrowed $33 million under our amended and restated five-year revolving credit agreement to redeem all of the outstanding Viking Gas Transmission Series A, B, C and D senior notes and paid a redemption premium of $3.6 million.

Cash distributions to our general and limited partners for 2007 were $384.6 million, compared with $265.5 million in 2006, an increase of $119.1 million, primarily due to the additional units that were issued to complete the ONEOK Transactions. Cash distributions to our general and limited partners increased $105.9 million for 2006, compared with 2005, due to increased available cash following the ONEOK Transactions described in this section under "Significant Acquisitions and Developments." We paid cash distributions of $3.98 per unit in 2007, compared with $3.60 per unit paid in 2006 and $3.20 per unit paid in 2005.

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Distributions to minority interests for 2006 decreased $60.5 million, compared with 2005, primarily due to the deconsolidation of Northern Border Pipeline. Distributions to minority interests for 2005 included distributions related to TC PipeLines' 30 percent interest in Northern Border Pipeline prior to the sale.

CONTRACTUAL OBLIGATIONS AND COMMERCIAL COMMITMENTS

The following table sets forth our contractual obligations related to debt, operating leases and other long-term obligations as of December 31, 2007. For further discussion of the debt and operating lease agreements, see Notes G and H, respectively, of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

	Payments Due by Period						
Contractual Obligations	**Total**	**2008**	**2009**	**2010**	**2011**	**2012**	**Thereafter**
	(Thousands of dollars)						
ONEOK Partners							
$1 billion credit agreement	$ 100,000	$100,000	$ -	$ -	$ -	$ -	$ -
Senior notes - 8.875%	250,000	-	-	250,000	-	-	-
Senior notes - 7.10%	225,000	-	-	-	225,000	-	-
Senior notes - 5.90%	350,000	-	-	-	-	350,000	-
Senior notes - 6.15%	450,000	-	-	-	-	-	450,000
Senior notes - 6.65%	600,000	-	-	-	-	-	600,000
Senior notes - 6.85%	600,000	-	-	-	-	-	600,000
Guardian Pipeline							
Senior notes - various	133,641	11,930	11,931	11,931	11,931	11,062	74,856
Interest payments on debt	2,789,800	177,600	176,700	163,700	140,000	120,200	2,011,600
Operating leases	87,964	18,698	13,784	12,745	12,622	5,847	24,268
Firm transportation contracts	26,820	11,881	11,260	3,679	-	-	-
Financial and physical derivatives	46,856	46,856	-	-	-	-	-
Purchase commitments, rights of way and other	58,366	52,971	935	935	935	935	1,655
Total	$5,718,447	$419,936	$214,610	$442,990	$390,488	$488,044	$ 3,762,379

Long-term Debt - Long-term debt as reported on our Consolidated Balance Sheets includes unamortized debt discount.

Interest Payments on Debt - Interest expense is calculated by taking long-term debt and multiplying it by the respective coupon rates.

Operating Leases - Our operating leases include a gas processing plant, storage contracts, office space, pipeline equipment, rights-of-way and vehicles. Our Processing and Services Agreement with ONEOK and OBPI sets out the terms by which OBPI provides processing and related services at the Bushton Plant through 2012. In exchange for such services, we pay OBPI for all direct costs and expenses of operating the Bushton Plant, including reimbursement of a portion of OBPI's obligations under equipment leases covering the Bushton Plant.

Firm Transportation Contracts - Firm transportation agreements with our Natural Gas Gathering and Processing segment's joint ventures require minimum monthly payments.

Financial and Physical Derivatives - Financial and physical derivatives represent fixed-price purchase commitments based on market information at December 31, 2007, associated with our Natural Gas Liquids Gathering and Fractionation segment.

Purchase Commitments - Purchase commitments include purchases related to our growth capital expenditures and other right of way commitments.

FORWARD-LOOKING STATEMENTS

Some of the statements contained and incorporated in this Annual Report on Form 10-K are forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. The forward-looking statements relate to our anticipated financial performance, management's plans and objectives for our future operations, our business prospects, the outcome of regulatory and legal proceedings, market conditions and other matters. The Private Securities Litigation Reform Act of 1995 provides a safe harbor for forward-looking statements in certain circumstances. The following discussion is intended to identify important factors that could cause future outcomes to differ materially from those set forth in the forward-looking statements.

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Forward-looking statements include the items identified in the preceding paragraph, the information concerning possible or assumed future results of our operations and other statements contained or incorporated in this Annual Report on Form 10-K identified by words such as "anticipate," "estimate," "expect," "project," "intend," "plan," "believe," "should," "goal," "forecast" and other words and terms of similar meaning.

You should not place undue reliance on forward-looking statements. Known and unknown risks, uncertainties and other factors may cause our actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by forward-looking statements. Those factors may affect our operations, markets, products, services and prices. In addition to any assumptions and other factors referred to specifically in connection with the forward-looking statements, factors that could cause our actual results to differ materially from those contemplated in any forward-looking statement include, among others, the following:

- the effects of weather and other natural phenomena on our operations, demand for our services and energy prices;
- competition from other United States and Canadian energy suppliers and transporters as well as alternative forms of energy;
- the capital intensive nature of our businesses;
- the profitability of assets or businesses acquired by us;
- risks of marketing, trading and hedging activities, including the risks of changes in energy prices or the financial condition of our counterparties;
- the uncertainty of estimates, including accruals and costs of environmental remediation;
- the timing and extent of changes in energy commodity prices;
- the effects of changes in governmental policies and regulatory actions, including changes with respect to income and other taxes, environmental compliance, authorized rates or recovery of gas and gas transportation costs;
- impact on drilling and production by factors beyond our control, including the demand for natural gas and refinery-grade crude oil; producers’ desire and ability to obtain necessary permits; reserve performance; and capacity constraints on the pipelines that transport crude oil, natural gas and NGLs from producing areas and our facilities;
- changes in demand for the use of natural gas because of market conditions caused by concerns about global warming or changes in governmental policies and regulations due to climate change initiatives;
- the impact of unforeseen changes in interest rates, equity markets, inflation rates, economic recession and other external factors over which we have no control, including the effect on pension expense and funding resulting from changes in stock and bond market returns;
- actions by rating agencies concerning the credit ratings of us or our general partner;
- the results of administrative proceedings and litigation, regulatory actions and receipt of expected clearances involving the OCC, KCC, Texas regulatory authorities or any other local, state or federal regulatory body, including the FERC;
- our ability to access capital at competitive rates or on terms acceptable to us;
- risks associated with adequate supply to our gathering, processing, fractionation and pipeline facilities, including production declines which outpace new drilling;
- the risk that material weaknesses or significant deficiencies in our internal control over financial reporting could emerge or that minor problems could become significant;
- the impact and outcome of pending and future litigation;
- the ability to market pipeline capacity on favorable terms, including the affects of:
  - future demand for and prices of natural gas and NGLs;
  - competitive conditions in the overall energy market;
  - availability of supplies of Canadian and United States natural gas;
  - availability of additional storage capacity;
  - weather conditions; and
  - competitive developments by Canadian and U.S. natural gas transmission peers;
- performance of contractual obligations by our customers, service providers, contractors and shippers;
- the timely receipt of approval by applicable governmental entities for construction and operation of our pipeline and other projects and required regulatory clearances;
- our ability to acquire all necessary rights-of-way permits and consents in a timely manner, to promptly obtain all necessary materials and supplies required for construction, and to construct pipelines without labor or contractor problems;
- the mechanical integrity of facilities operated;
- demand for our services in the proximity of our facilities;
- our ability to control operating costs;

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- acts of nature, sabotage, terrorism or other similar acts that cause damage to our facilities or our suppliers' or shippers' facilities;
- economic climate and growth in the geographic areas in which we do business;
- the risk of a significant slowdown in growth or decline in the U.S. economy or the risk of delay in growth recovery in the U.S. economy;
- the impact of recently issued and future accounting pronouncements and other changes in accounting policies;
- the possibility of future terrorist attacks or the possibility or occurrence of an outbreak of, or changes in, hostilities or changes in the political conditions in the Middle East and elsewhere;
- the risk of increased costs for insurance premiums, security or other items as a consequence of terrorist attacks;
- risks associated with pending or possible acquisitions and dispositions, including our ability to finance or integrate any such acquisitions and any regulatory delay or conditions imposed by regulatory bodies in connection with any such acquisitions and dispositions;
- the impact of unsold pipeline capacity being greater or less than expected;
- the ability to recover operating costs and amounts equivalent to income taxes, costs of property, plant and equipment and regulatory assets in our state and FERC-regulated rates;
- our ability to promptly obtain all necessary materials and supplies required for construction of gathering, processing, storage, fractionation and transportation facilities;
- the composition and quality of the natural gas and NGLs we gather and process in our plants and transport on our pipelines;
- the efficiency of our plants in processing natural gas and extracting and fractionating NGLs;
- the impact of potential impairment charges;
- the risk inherent in the use of information systems in our respective businesses, implementation of new software and hardware, and the impact on the timeliness of information for financial reporting;
- our ability to control construction costs and completion schedules of our pipelines and other projects; and
- the risk factors listed in the reports we have filed and may file with the SEC, which are incorporated by reference.

These factors are not necessarily all of the important factors that could cause actual results to differ materially from those expressed in any of our forward-looking statements. Other factors could also have material adverse effects on our future results. These and other risks are described in greater detail in Item 1A, Risk Factors, in this Annual Report on Form 10-K. All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by these factors. Other than as required under securities laws, we undertake no obligation to update publicly any forward-looking statement whether as a result of new information, subsequent events or change in circumstances, expectations or otherwise.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Our exposure to market risk discussed below includes forward-looking statements and represents an estimate of possible changes in future earnings that could occur assuming hypothetical future movements in interest rates or commodity prices. Our views on market risk are not necessarily indicative of actual results that may occur and do not represent the maximum possible gains and losses that may occur since actual gains and losses will differ from those estimated based on actual fluctuations in interest rates or commodity prices and the timing of transactions.

We are exposed to market risk due to interest rate and commodity price volatility. Market risk is the risk of loss arising from adverse changes in market rates and prices. We may use financial instruments, including forwards, swaps, collars and futures, to manage the risks of certain identifiable or anticipated transactions and achieve a more predictable cash flow. Our risk management function follows established policies and procedures to monitor interest rates and natural gas and natural gas liquids marketing activities to ensure our hedging activities mitigate market risks. We do not use financial instruments for trading purposes.

In accordance with Statement 133, "Accounting for Derivative Instruments and Hedging Activities," as amended, we record derivative instruments on the balance sheet as assets and liabilities based on fair value. We estimate the fair value of derivative instruments using available market information and appropriate valuation techniques. Changes in derivative instruments' fair value are recognized in earnings unless the instrument qualifies as a hedge under Statement 133 and meets specific hedge accounting criteria. Qualifying derivative instruments' gains and losses may offset the hedged items' related results in earnings for a fair value hedge or be deferred in accumulated other comprehensive income (loss) for a cash flow hedge.

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INTEREST RATE RISK

General - We are subject to the risk of interest rate fluctuation in the normal course of business. We manage interest rate risk through the use of fixed-rate debt, floating-rate debt and, at times, interest-rate swaps. Fixed-rate swaps are used to reduce our risk of increased interest costs during periods of rising interest rates. Floating-rate swaps are used to convert the fixed rates of long-term borrowings into short-term variable rates.

We terminated two floating-rate swaps in 2007. The total value we received for the terminated swaps was not material. At December 31, 2007, the interest rate on all of our long-term debt was fixed.

Fair Value Hedges - See Note C of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for discussion of the impact of interest-rate swaps and net interest expense savings from terminated swaps.

Total swap savings for 2007 were $2.5 million, compared with the savings of $2.0 million in 2006. Total swap savings from terminated swaps for 2008 are expected to be $3.7 million.

COMMODITY PRICE RISK

Our Natural Gas Gathering and Processing segment is exposed to commodity price risk, primarily NGLs, as a result of receiving commodities in exchange for our services. To a lesser extent, exposures arise from the relative price differential between NGLs and natural gas, or the gross processing spread, with respect to our keep-whole processing contracts and the risk of price fluctuations and the cost of intervening transportation at various market locations. We use commodity fixed-price physical forwards and derivative contracts, including NYMEX-based futures and over-the-counter swaps, to minimize earnings volatility related to natural gas, NGL and condensate price fluctuations.

We reduce our gross processing spread exposure through a combination of physical and financial hedges. We utilize a portion of our POP equity natural gas as an offset, or natural hedge, to an equivalent portion of our keep-whole shrink requirements. This has the effect of converting our gross processing spread risk to NGL commodity price risk and we then use financial instruments to hedge the sale of NGLs.

The following table sets forth our Natural Gas Gathering and Processing segment’s hedging information for the year ending December 31, 2008.

	Year Ending December 31, 2008		
	Volumes Hedged	**Average Price Per Unit**	**Volumes Hedged**
Natural gas liquids *(Bbl/d)* (a)	8,085	$ 1.28 *($/gallon)*	70%
Condensate *(Bbl/d)* (a)	818	$ 2.15 *($/gallon)*	74%
Total liquid sales *(Bbl/d)*	8,903	$ 1.36 *($/gallon)*	71%

(a) - Hedged with fixed-price swaps.

Our commodity price risk is estimated as a hypothetical change in the price of NGLs, crude oil and natural gas at December 31, 2007, excluding the effects of hedging and assuming normal operating conditions. Our condensate sales are based on the price of crude oil. We estimate the following:

- a $0.01 per gallon increase in the composite price of NGLs would increase annual net margin by approximately $1.7 million,
- a $1.00 per barrel increase in the price of crude oil would increase annual net margin by approximately $0.5 million, and
- a $0.10 per MMBtu increase in the price of natural gas would increase annual net margin by approximately $0.3 million.

The above estimates of commodity price risk do not include any effects on demand for our services that might be caused by, or arise in conjunction with, price changes. For example, a change in the gross processing spread may cause ethane to be sold in the natural gas stream, impacting gathering and processing margins, NGL exchange margins, natural gas deliveries and NGL volumes shipped.

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Our Natural Gas Liquids Gathering and Fractionation segment is exposed to commodity price risk primarily as a result of NGLs in storage, spread risk associated with the relative values of the various NGL products and the relative value of NGL purchases at one location and sales at another location, known as basis risk. We have not entered into any hedges with respect to our NGL marketing activities.

Our Natural Gas Pipelines segment is exposed to commodity price risk because our intrastate and interstate natural gas pipelines collect natural gas from their customers for operations as part of their fee for services provided. When the amount of natural gas consumed in operations by these pipelines differs from the amount provided by their customers, our pipelines must buy or sell natural gas, or store or use natural gas from inventory, which exposes us to commodity price risk. At December 31, 2007, there were no hedges in place with respect to natural gas price risk from our intrastate and interstate pipeline operations.

See Note C of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for more information on our hedging activities.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of ONEOK Partners GP, L.L.C. as General Partner of ONEOK Partners, L.P. and to the Unitholders:

In our opinion, the accompanying consolidated balance sheet and the related consolidated statement of income, partners' equity and comprehensive income and cash flows present fairly, in all material respects, the financial position of ONEOK Partners, L.P. and its subsidiaries (the Partnership) at December 31, 2007, and the results of their operations and their cash flows for the year ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Partnership's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A in the Partnership's Form 10-K for the year ended December 31, 2007. Our responsibility is to express opinions on these financial statements and on the Partnership's internal control over financial reporting based on our integrated audit. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audit of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

February 27, 2008
Tulsa, Oklahoma

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of ONEOK Partners GP, L.L.C. as General Partner of ONEOK Partners, L.P. and to the Unitholders:

We have audited the accompanying consolidated balance sheet of ONEOK Partners, L.P. and subsidiaries (the Partnership) (formerly Northern Border Partners, L.P.) as of December 31, 2006, and the related consolidated statements of income, cash flows, and changes in partners' equity and comprehensive income for each of the years in the two-year period ended December 31, 2006. These consolidated financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of ONEOK Partners, L.P. and subsidiaries as of December 31, 2006, and the results of their operations and their cash flows for each of the years in the two-year period ended December 31, 2006, in conformity with U.S. generally accepted accounting principles.

/s/ KPMG LLP

Tulsa Oklahoma
February 28, 2007, except for Note J, as to which the date is February 27, 2008

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ONEOK Partners, L.P. and Subsidiaries
CONSOLIDATED STATEMENTS OF INCOME

	Years Ended December 31, 2007	2006	2005
	(Thousands of dollars, except per unit amounts)		
Revenues			
Operating revenue	**$ 5,831,558**	$ 4,738,248	$ 703,944
Cost of sales and fuel	**4,935,665**	3,894,700	210,082
Net Margin	**895,893**	843,548	493,862
Operating Expenses			
Operations and maintenance	**302,544**	294,207	112,509
Depreciation and amortization	**113,704**	122,045	86,010
General taxes	**34,812**	31,567	38,575
Total Operating Expenses	**451,060**	447,819	237,094
Gain on Sale of Assets	**1,950**	115,483	-
Operating Income	**446,783**	511,212	256,768
Equity earnings from investments (Note K)	**89,908**	95,883	24,736
Allowance for equity funds used during construction	**12,538**	2,205	527
Other income	**7,502**	6,510	3,552
Other expense	**779**	7,081	707
Interest expense	**138,947**	133,482	86,903
Income before Minority Interests and Income Taxes	**417,005**	475,247	197,973
Minority interests in income of consolidated subsidiaries	**416**	2,392	45,674
Income before income taxes	**416,589**	472,855	152,299
Income taxes	**8,842**	27,669	5,792
Income from Continuing Operations	**407,747**	445,186	146,507
Discontinued operations, net of tax	**-**	-	506
Net Income	**$ 407,747**	$ 445,186	$ 147,013
Limited partners' interest in net income:			
Net income	**$ 407,747**	$ 445,186	$ 147,013
General partners' interest in net income	**58,781**	75,654	10,900
Limited Partners' Interest in Net Income	**$ 348,966**	$ 369,532	$ 136,113
Limited partners' per unit net income:			
Income from continuing operations	**$ 4.21**	$ 5.01	$ 2.92
Discontinued operations, net of tax	**-**	-	0.01
Net income per unit (Note L)	**$ 4.21**	$ 5.01	$ 2.93
Number of Units Used in Computation *(Thousands)*	**82,891**	73,768	46,397

See accompanying Notes to Consolidated Financial Statements.

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ONEOK Partners, L.P. and Subsidiaries
CONSOLIDATED BALANCE SHEETS

	December 31, 2007	December 31, 2006
Assets	*(Thousands of dollars)*	
Current Assets		
Cash and cash equivalents	**$ 3,213**	$ 21,102
Accounts receivable, net	**577,989**	298,602
Affiliate receivables	**52,479**	88,572
Gas and natural gas liquids in storage	**251,219**	198,141
Commodity exchanges and imbalances	**82,037**	53,433
Other	**19,961**	33,388
Total Current Assets	**986,898**	693,238
Property, Plant and Equipment		
Property, plant and equipment	**4,436,371**	3,424,452
Accumulated depreciation and amortization	**776,185**	660,804
Net Property, Plant and Equipment (Note A)	**3,660,186**	2,763,648
Investments and Other Assets		
Investments in unconsolidated affiliates (Note K)	**756,260**	748,879
Goodwill and intangible assets (Note D)	**682,084**	689,751
Other	**26,637**	26,201
Total Investments and Other Assets	**1,464,981**	1,464,831
Total Assets	**$ 6,112,065**	$ 4,921,717
Liabilities and Partners' Equity		
Current Liabilities		
Current maturities of long-term debt	**$ 11,930**	$ 11,931
Notes payable	**100,000**	6,000
Accounts payable	**742,903**	361,967
Affiliate payables	**18,298**	25,737
Commodity exchanges and imbalances	**252,095**	175,927
Other	**136,664**	89,471
Total Current Liabilities	**1,261,890**	671,033
Long-term Debt, net of current maturities	**2,605,396**	2,019,598
Deferred Credits and Other Liabilities	**43,799**	36,818
Commitments and Contingencies		
Minority Interests in Consolidated Subsidiaries	**5,802**	5,606
Partners' Equity		
General partner	**58,415**	54,373
Common units: 46,397,214 units issued and outstanding at December 31, 2007 and 2006	**814,266**	803,599
Class B units: 36,494,126 units issued and outstanding at December 31, 2007 and 2006	**1,340,638**	1,332,276
Accumulated other comprehensive loss	**(18,141)**	(1,586)
Total Partners' Equity	**2,195,178**	2,188,662
Total Liabilities and Partners' Equity	**$ 6,112,065**	$ 4,921,717

See accompanying Notes to Consolidated Financial Statements.

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ONEOK Partners, L.P. and Subsidiaries
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2007	**2006**	**2005**
Operating Activities	*(Thousands of dollars)*		
Net income	**$ 407,747**	$ 445,186	$ 147,013
Depreciation and amortization	**113,704**	122,045	86,361
Allowance for equity funds used during construction	**(12,538)**	(2,205)	(527)
Minority interests in income of consolidated subsidiaries	**416**	2,392	45,674
Equity earnings from investments	**(89,908)**	(95,883)	(24,736)
Distributions received from unconsolidated affiliates	**103,785**	123,427	16,440
Gain on sale of assets	**(1,950)**	(115,483)	-
Changes in assets and liabilities (net of acquisition and disposition effects):			
Accounts receivable	**(232,870)**	42,148	(12,840)
Inventories	**(50,042)**	19,093	(2,583)
Accounts payable and other current liabilities	**361,013**	7,697	16,260
Commodity exchanges and imbalances, net	**41,997**	20,129	-
Accrued taxes other than income	**3,099**	(6,358)	518
Accrued interest	**9,069**	23,445	915
Derivative financial instruments	**3,028**	(5,220)	(106)
Other assets and liabilities	**44,984**	22,805	(5,017)
Cash Provided by Operating Activities	**701,534**	603,218	267,372
Investing Activities			
Investments in unconsolidated affiliates	**(3,668)**	(6,608)	(8,537)
Acquisitions	**(299,560)**	(1,396,893)	-
Proceeds from sale of assets	**3,980**	297,674	-
Capital expenditures (less allowance for equity funds used during construction)	**(709,858)**	(201,746)	(59,882)
Increase in cash and cash equivalents attributable to previously unconsolidated subsidiaries	**-**	7,496	-
Decrease in cash and cash equivalents attributable to previously consolidated subsidiaries	-	(22,039)	-
Cash Used in Investing Activities	**(1,009,106)**	(1,322,116)	(68,419)
Financing Activities			
Cash distributions:			
General and limited partners	**(384,646)**	(265,479)	(159,624)
Minority interests	**(220)**	(343)	(60,870)
Cash flow retained by ONEOK (Note B)	-	(177,486)	-
Borrowing (repayment) of notes payable, net	**94,000**	(200,500)	40,000
Issuance of long-term debt, net of discounts	**598,146**	1,397,327	-
Long-term debt financing costs	**(5,805)**	(12,003)	(1,382)
Payment of long-term debt	**(11,931)**	(40,978)	(5,182)
Other financing activities	**139**	(3,628)	(2,785)
Cash Provided by (Used in) Financing Activities	**289,683**	696,910	(189,843)
Change in Cash and Cash Equivalents	**(17,889)**	(21,988)	9,110
Cash and Cash Equivalents at Beginning of Period	**21,102**	43,090	33,980
Cash and Cash Equivalents at End of Period	**$ 3,213**	$ 21,102	$ 43,090
Supplemental Cash Flow Information:			
Cash Paid for Interest	**$ 138,606**	$ 86,290	$ 91,168

See accompanying Notes to Consolidated Financial Statements.

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ONEOK Partners, L.P. and Subsidiaries
CONSOLIDATED STATEMENT OF CHANGES IN PARTNERS' EQUITY AND COMPREHENSIVE INCOME

	Common Units	Class B Units	General Partner	Common Units
	(Units)		*(Thousands of dollars)*	
Partners' equity at December 31, 2004	46,397,214	-	$ 17,593	$ 762,560
Net income	-	-	10,900	136,113
Other comprehensive loss	-	-	-	-
Total comprehensive income				
Distributions paid	-	-	(11,152)	(148,472)
Partners' equity at December 31, 2005	46,397,214	-	17,341	750,201
Net income	-	-	75,654	220,428
Other comprehensive income	-	-	-	-
Total comprehensive income				
Net Income retained by ONEOK (Note B)	-	-	(35,818)	-
Issuance of Class B units and contribution from general partner	-	36,494,126	25,576	-
Distributions paid	-	-	(28,380)	(167,030)
Partners' equity at December 31, 2006	46,397,214	36,494,126	54,373	803,599
Net income	**-**	**-**	**58,781**	**195,329**
Other comprehensive loss	**-**	**-**	**-**	**-**
Total comprehensive income				
Other	**-**	**-**	**(1)**	**-**
Distributions paid	**-**	**-**	**(54,738)**	**(184,662)**
Partners' equity at December 31, 2007	**46,397,214**	**36,494,126**	**$ 58,415**	**$ 814,266**

See accompanying Notes to Consolidated Financial Statements.

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ONEOK Partners, L.P. and Subsidiaries
CONSOLIDATED STATEMENT OF CHANGES IN PARTNERS' EQUITY AND COMPREHENSIVE INCOME
(Continued)

	Class B Units	Accumulated Other Comprehensive Income (Loss)	Total Partners' Equity
		(Thousands of dollars)	
Partners' equity at December 31, 2004	$ -	$ 9,181	$ 789,334
Net income	-	-	147,013
Other comprehensive loss	-	(11,134)	(11,134)
Total comprehensive income			135,879
Distributions paid	-	-	(159,624)
Partners' equity at December 31, 2005	-	(1,953)	765,589
Net income	149,104	-	445,186
Other comprehensive income	-	367	367
Total comprehensive income			445,553
Net Income retained by ONEOK (Note B)	-	-	(35,818)
Issuance of Class B units and contribution from general partner	1,253,241	-	1,278,817
Distributions paid	(70,069)	-	(265,479)
Partners' equity at December 31, 2006	1,332,276	(1,586)	2,188,662
Net income	**153,637**	**-**	**407,747**
Other comprehensive loss	**-**	**(16,555)**	**(16,555)**
Total comprehensive income			**391,192**
Other	**(29)**	**-**	**(30)**
Distributions paid	**(145,246)**	**-**	**(384,646)**
Partners' equity at December 31, 2007	**$ 1,340,638**	**$ (18,141)**	**$ 2,195,178**

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ONEOK PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

A. SUMMARY OF ACCOUNTING POLICIES

Nature of Operations - ONEOK Partners, L.P. is a publicly traded Delaware limited partnership that was formed in 1993. Our common units are listed on the NYSE under the trading symbol "OKS." We own and manage natural gas gathering, processing, storage and interstate and intrastate pipeline assets and natural gas liquids gathering and distribution pipelines, storage and fractionators, connecting much of the natural gas and NGL supply in the Mid-Continent and Gulf Coast regions with key market centers in Conway, Kansas, Mont Belvieu, Texas, and Chicago, Illinois. We also own a 50 percent interest in a leading transporter of natural gas imported from Canada into the United States.

Critical Accounting Policies

The following is a summary of our most critical accounting policies, which are defined as those policies most important to the portrayal of our financial condition and results of operations and requiring management's most difficult, subjective, or complex judgment, particularly because of the need to make estimates concerning the impact of inherently uncertain matters. We have discussed the development and selection of our critical accounting policies and estimates with the Audit Committee of our Board of Directors.

Impairment of Long-Lived Assets, Goodwill and Intangible Assets - We assess our long-lived assets for impairment based on Statement 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." A long-lived asset is tested for impairment whenever events or changes in circumstances indicate that its carrying amount may exceed its fair value. Fair values are based on the sum of the undiscounted future cash flows expected to result from the use and eventual disposition of the assets.

We assess our goodwill and intangible assets for impairment at least annually based on Statement 142, "Goodwill and Other Intangible Assets." An initial assessment is made by comparing the fair value of the operations with goodwill, as determined in accordance with Statement 142, to the book value of each reporting unit. If the fair value is less than the book value, an impairment is indicated, and we must perform a second test to measure the amount of the impairment. In the second test, we calculate the implied fair value of the goodwill by deducting the fair value of all tangible and intangible net assets of the operations with goodwill from the fair value determined in step one of the assessment. If the carrying value of the goodwill exceeds this calculated implied fair value of the goodwill, we will record an impairment charge. See Note D for more discussion of goodwill.

Intangible assets with a finite useful life are amortized over their estimated useful life, while intangible assets with an indefinite useful life are not amortized. All intangible assets are subject to impairment testing.

For the investments we account for under the equity method, the premium or excess cost over underlying fair value of net assets is referred to as equity method goodwill and under Statement 142, is not subject to amortization but rather to impairment testing pursuant to APB Opinion No. 18, "The Equity Method of Accounting for Investments in Common Stock." The impairment test under APB Opinion No. 18 considers whether the fair value of the equity investment as a whole, not the underlying net assets, has declined and whether that decline is other than temporary. Therefore, we periodically reevaluate the amount at which we carry the excess of cost over fair value of net assets accounted for under the equity method to determine whether current events or circumstances warrant adjustments to our carrying value in accordance with APB Opinion No. 18.

Derivatives and Risk Management - We utilize financial instruments to reduce our market risk exposure to interest rate and commodity price fluctuations and achieve more predictable cash flows. We account for derivative instruments utilized in connection with these activities and services under the fair value basis of accounting in accordance with Statement 133, "Accounting for Derivative Instruments and Hedging Activities," as amended.

Under Statement 133, entities are required to record derivative instruments at fair value. The fair value of a derivative instrument is determined by commodity exchange prices, over-the-counter quotes, volatility, time value, counterparty credit and the potential impact on market prices of liquidating positions in an orderly manner over a reasonable period of time under current market conditions.

Market value changes result in a change in the fair value of our derivative instruments. The accounting for changes in the fair value of a derivative instrument depends on whether it has been designated and qualifies as part of a hedging relationship and, if so, the nature of the risk being hedged and how we will determine if the hedging instrument is effective. If the

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derivative instrument does not qualify or is not designated as part of a hedging relationship, then we account for changes in fair value of the derivative in earnings as they occur. Commodity price volatility may have a significant impact on the gain or loss in a given period.

To minimize the risk of fluctuations in natural gas, NGLs and condensate prices, we periodically enter into futures, collars or swap transactions in order to hedge anticipated purchases and sales of natural gas, NGLs, condensate, and fuel requirements. Interest rate swaps are also used to manage interest rate risk. Under certain conditions, we designate these derivative instruments as a hedge of exposure to changes in fair values or cash flow. For hedges of exposure to changes in cash flow, the effective portion of the gain or loss on the derivative instrument is reported initially as a component of accumulated other comprehensive income (loss) and subsequently recorded to earnings when the forecasted transaction affects earnings. Any ineffectiveness of designated hedges is reported in earnings in the period the ineffectiveness occurs. For hedges of exposure to changes in fair value, the gain or loss on the derivative instrument is recognized in earnings during the period of change together with the offsetting gain or loss on the hedged item attributable to the risk being hedged.

Upon election, many of our purchase and sale agreements that otherwise would be required to follow derivative accounting qualify as normal purchases and normal sales under Statement 133 and are therefore exempt from fair value accounting treatment.

See Note C for more discussion of derivatives and risk management activities.

Contingencies - Our accounting for contingencies covers a variety of business activities, including contingencies for legal and environmental exposures. We accrue these contingencies when our assessments indicate that it is probable that a liability has been incurred or an asset will not be recovered and an amount can be reasonably estimated in accordance with Statement 5, "Accounting for Contingencies." We base our estimates on currently available facts and our estimates of the ultimate outcome or resolution. Actual results may differ from our estimates resulting in an impact, positive or negative, on earnings. See Note H for additional discussion of contingencies.

Significant Accounting Policies

Consolidation - Our consolidated financial statements include the assets, liabilities and results of operations for our majority-owned subsidiaries. All significant intercompany balances and transactions have been eliminated in consolidation. We account for our investments that we do not control by the equity method of accounting. Under this method, an investment is carried at its acquisition cost, plus the equity in undistributed earnings or losses since acquisition. Minority interest for 2006 primarily represents the 66-2/3 percent interest in Guardian Pipeline that we did not own until we acquired these interests in April 2006. Minority interest for 2005 represents the 30 percent interest in Northern Border Pipeline owned by TC PipeLines when Northern Border Pipeline's results were consolidated.

Use of Estimates - The preparation of our consolidated financial statements and related disclosures in accordance with GAAP requires us to make estimates and assumptions with respect to values or conditions that cannot be known with certainty that affect the reported amount of assets and liabilities, and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements. These estimates and assumptions also affect the reported amounts of revenue and expenses during the reporting period. Items which may be estimated include, but are not limited to, the economic useful life of assets, fair value of assets and liabilities, provisions for uncollectible accounts receivable, unbilled revenues and cost of goods sold, expenses for services received but for which no invoice has been received, the results of litigation and various other recorded or disclosed amounts.

We evaluate these estimates on an ongoing basis using historical experience, consultation with experts and other methods we consider reasonable based on the particular circumstances. Nevertheless, actual results may differ significantly from the estimates. Any effects on our financial position or results of operations from revisions to these estimates are recorded in the period when the facts that give rise to the revision become known.

Regulation - Our intrastate natural gas transmission pipelines are subject to the rate regulation and accounting requirements of the OCC, KCC and RRC. Our interstate natural gas and natural gas liquids pipelines are subject to regulation by the FERC. Accordingly, portions of our Natural Gas Pipelines segment and Natural Gas Liquids Pipelines segment follow the accounting and reporting guidance contained in Statement 71, "Accounting for the Effects of Certain Types of Regulation." During the rate-making process, regulatory authorities may allow us to defer recognition of certain costs and permit recovery of the amounts through rates over time as opposed to expensing such costs as incurred. This allows us to stabilize rates over time rather than passing such costs on to the customer for immediate recovery. Actions by regulatory authorities could have an effect on the amount recovered from rate payers. Any difference in the amount recoverable and the amount deferred is

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recorded as income or expense at the time of the regulatory action. If all or a portion of the regulated operations are no longer subject to the provisions of Statement 71, a write-off of regulatory assets and costs not recovered may be required.

At December 31, 2007 and 2006, we recorded regulatory assets of approximately $6.8 million and $9.2 million, respectively, which are currently being recovered or are expected to be recovered from our customers. Regulatory assets are being recovered as a result of approved rate proceedings over varying time periods up to 40 years. These assets are reflected in other assets on our Consolidated Balance Sheets.

Asset Retirement Obligations - Statement 143, "Accounting for Asset Retirement Obligations," applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or normal use of the asset. Statement 143 requires that we recognize the fair value of a liability for an asset retirement obligation in the period when it is incurred if a reasonable estimate of the fair value can be made. The fair value of the liability is added to the carrying amount of the associated asset and this additional carrying amount is depreciated over the life of the asset. The liability is accreted at the end of each period through charges to operating expense. If the obligation is settled for an amount other than the carrying amount of the liability, we will recognize a gain or loss on settlement. The depreciation and amortization expense is immaterial to our consolidated financial statements.

In accordance with long-standing regulatory treatment, we collect through rates the estimated costs of removal on certain regulated properties through depreciation expense, with a corresponding credit to accumulated depreciation and amortization. These removal costs are non-legal obligations as defined by Statement 143. However, these non-legal asset removal obligations are accounted for as a regulatory liability under Statement 71. Historically, the regulatory authorities that have jurisdiction over our regulated operations have not required us to track this amount; rather these costs are addressed prospectively as depreciation rates and are set in each general rate order. We have made an estimate of our removal cost liability using current rates since the last general rate order in each of our jurisdictions. However, significant uncertainty exists regarding the ultimate determination of this liability pending, among other issues, clarification of regulatory intent. We continue to monitor the regulatory authorities and the liability may be adjusted as more information is obtained.

Cash and Cash Equivalents - Cash equivalents consist of highly liquid investments, which are readily convertible into cash and have original maturities of three months or less.

Revenue Recognition - Our operating segments recognize revenue when services are rendered or product is delivered. Our Natural Gas Gathering and Processing segment records operating revenue when gas is processed in or transported through company facilities. Our Natural Gas Liquids Gathering and Fractionation segment records operating revenues based upon contracted services and actual volumes exchanged or stored under service agreements in the period services are provided. Operating revenue for our Natural Gas Pipelines segment and Natural Gas Liquids Pipelines segment is recognized based upon contracted capacity and contracted volumes transported and stored under service agreements in the period services are provided.

Property - The following table sets forth our property, by segment, for the periods presented.

	December 31, 2007	December 31, 2006
	(Thousands of dollars)	
Non-Regulated		
Natural Gas Gathering and Processing	**$ 1,227,475**	$ 1,133,614
Natural Gas Pipelines	**162,390**	162,636
Natural Gas Liquids Gathering and Fractionation	**672,047**	547,495
Other	**50,482**	50,784
Regulated		
Natural Gas Pipelines	**1,184,112**	1,040,125
Natural Gas Liquids Pipelines	**1,139,865**	489,798
Property, plant and equipment	**4,436,371**	3,424,452
Accumulated depreciation and amortization	**776,185**	660,804
Net property, plant and equipment	**$ 3,660,186**	$ 2,763,648

Gas processing plants, natural gas liquids fractionation plants and all other properties are stated at cost. Gas processing plants, natural gas liquids fractionation plants and all other property and equipment are depreciated using the straight-line method over the estimated useful life.

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Generally, we apply composite depreciation rates to functional groups of property having similar economic circumstances.

At December 31, 2007 and 2006, property, plant and equipment on our Consolidated Balance Sheets included construction work in progress of $859.8 million and $100.5 million, respectively, that had not yet been put in service and therefore was not being depreciated.

Certain maintenance and repairs are charged directly to expense. Gains and losses from sales or transfers of an entire operating unit or system are recognized in income.

We capitalize interest expense during the construction or upgrade of qualifying assets. Interest expense capitalized in 2007, 2006 and 2005 was $14.3 million, $1.2 million and $0.8 million, respectively. Capitalized interest is recorded as a reduction to interest expense.

Regulated properties are stated at cost, which includes the equity portion of AFUDC. The equity portion of AFUDC represents the capitalization of the estimated average cost of equity used during the construction of major projects and is recorded as a credit to the allowance for equity funds used during construction. Generally, the cost of property retired or sold, plus removal costs, less salvage, is charged to accumulated depreciation.

The average depreciation rates for our regulated property are set forth in the following table for the periods indicated.

	Years Ended December 31,		
Regulated Property	**2007**	**2006**	**2005**
Natural Gas Pipelines	**2.4%**	2.4%	2.7%
Natural Gas Liquids Pipelines	**2.5%**	2.6%	2.7%

Income Taxes - We are not a taxable entity for federal income tax purposes. As such, we do not directly pay federal income tax. Our taxable income or loss, which may vary substantially from the net income or loss reported in our Consolidated Statements of Income, is included in the federal income tax returns of each partner. The aggregate difference in the basis of our net assets for financial and income tax purposes cannot be readily determined, as we do not have access to all information about each partner's tax attributes related to us.

Our corporate subsidiaries are required to pay federal and state income taxes. Income taxes are accounted for using the provisions of Statement 109, "Accounting for Income Taxes." Deferred income taxes are provided for the difference between the financial statement and income tax basis of assets and liabilities and carryforward items based on income tax laws and rates existing at the time the temporary differences are expected to reverse. Except for the companies whose accounting policies conform to Statement 71, the effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period that includes the enactment date of the rate change. For the companies whose accounting policies conform to Statement 71, the effect on deferred tax assets and liabilities of a change in tax rates is recorded as regulatory assets and regulatory liabilities in the period that includes the enactment date.

In June 2006, the FASB issued FIN 48, "Accounting for Uncertainty in Income Taxes - An Interpretation of FASB Statement No. 109," which is effective for our year beginning January 1, 2007. This interpretation was issued to clarify the accounting for uncertainty in income taxes recognized in the financial statements by prescribing a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN 48 requires the recognition of penalties and interest on any unrecognized tax benefits. Our policy is to reflect penalties and interest as part of income tax expense as they become applicable. During 2007, we had no tax positions that would require establishment of a reserve under FIN 48.

We file numerous consolidated and separate income tax returns in the United States federal jurisdiction and in many state jurisdictions. We also file returns in Canada. No returns are currently under audit, and no extensions of statute of limitations have been requested or granted.

Environmental Expenditures - We accrue for losses associated with environmental remediation obligations when such losses are probable and reasonably estimable. Accruals for estimated losses from environmental remediation obligations generally are recognized no later than completion of the remediation feasibility study. Such accruals are adjusted as further information becomes available or as circumstances change. Recoveries of environmental remediation costs from other parties are recorded as assets when their receipt is deemed probable.

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Inventory, Natural Gas Imbalances and Commodity Exchanges - Inventory is valued at the lower of cost or market. The values of current natural gas and NGLs in storage are determined using the lower of cost or market method. Noncurrent natural gas is classified as property and valued at cost. Materials and supplies are valued at average cost. Natural gas imbalances and NGL exchanges are valued at market or their contractually stipulated rate. Imbalances and NGL exchanges are settled in cash or made up in kind, subject to the terms of the pipelines' tariffs or by agreement.

Other

Fair Value Measurements - In September 2006, the FASB issued Statement 157, "Fair Value Measurements," which establishes a framework for measuring fair value and requires additional disclosures about fair value measurements. Beginning January 1, 2008, we partially applied Statement 157 as allowed by FASB Staff Position (FSP) 157-2, which delayed the effective date of Statement 157 for nonfinancial assets and liabilities. As of January 1, 2008, we have applied the provisions of Statement 157 to our financial instruments and the impact was not material. Under FSP 157-2, we will be required to apply Statement 157 to our nonfinancial assets and liabilities beginning January 1, 2009. We are currently reviewing the applicability of Statement 157 to our nonfinancial assets and liabilities as well as the potential impact on our consolidated financial statements.

In February 2007, the FASB issued Statement 159, "The Fair Value Option for Financial Assets and Financial Liabilities," which allows companies to elect to measure specified financial assets and liabilities, firm commitments, and nonfinancial warranty and insurance contracts at fair value on a contract-by-contract basis, with changes in fair value recognized in earnings each reporting period. At January 1, 2008, we did not elect the fair value option under Statement 159 and therefore there was no impact to our consolidated financial statements.

Business Combinations - In December 2007, the FASB issued Statement 141R, "Business Combinations," which will require most identifiable assets, liabilities, noncontrolling interest (previously referred to as minority interests) and goodwill acquired in a business combination to be recorded at full fair value. Statement 141R is effective for our year beginning January 1, 2009, and will be applied prospectively. We are currently reviewing the applicability of Statement 141R to our operations and its potential impact on our consolidated financial statements.

Noncontrolling Interests - In December 2007, the FASB issued Statement 160, "Noncontrolling Interest in Consolidated Financial Statements - an amendment to ARB No. 51," which requires noncontrolling interests (previously referred to as minority interests) to be reported as a component of equity. Statement 160 is effective for our year beginning January 1, 2009, and will require retroactive adoption of the presentation and disclosure requirements for existing minority interests. We are currently reviewing the applicability of Statement 160 to our operations and its potential impact on our consolidated financial statements.

Reclassifications - Certain amounts in our consolidated financial statements have been reclassified to conform to the 2007 presentation. These reclassifications did not impact previously reported net income or partners' equity.

B. ACQUISITIONS AND DIVESTITURES

Acquisition of NGL Pipeline - In October 2007, we completed the acquisition of an interstate natural gas liquids and refined petroleum products pipeline system and related assets from a subsidiary of Kinder Morgan Energy Partners, L.P. (Kinder Morgan) for approximately $300 million, before working capital adjustments. The system extends from Bushton and Conway, Kansas, to Chicago, Illinois, and transports, stores and delivers a full range of NGL and refined petroleum products. The FERC-regulated system spans 1,627 miles and has a capacity to transport up to 134 MBbl/d. The transaction includes approximately 978 MBbl of owned storage capacity, eight NGL terminals and a 50 percent ownership of Heartland. ConocoPhillips owns the other 50 percent of Heartland and is the managing partner of the Heartland joint venture, which consists primarily of three refined petroleum products terminals and connecting pipelines. Financing for this transaction came from the proceeds of our September 2007 issuance of $600 million 6.85 percent Senior Notes due 2037 (the 2037 Notes). See Note G for a discussion on the 2037 Notes. The working capital settlement has not been finalized; however, we do not expect material adjustments.

Overland Pass Pipeline Company - In May 2006, we entered into an agreement with a subsidiary of The Williams Companies, Inc. (Williams) to form a joint venture called Overland Pass Pipeline Company. Overland Pass Pipeline Company is building a 760-mile natural gas liquids pipeline from Opal, Wyoming, to the Mid-Continent natural gas liquids market center in Conway, Kansas. The pipeline is designed to transport approximately 110 MBbl/d of unfractionated NGLs, which can be increased to approximately 150 MBbl/d with additional pump facilities. During 2006, we paid $11.6 million to Williams for acquisition of our interest in the joint venture and for reimbursement of initial capital expenditures. As the 99 percent owner of the joint venture, we will manage the construction project, advance all costs associated with construction

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and operate the pipeline. Within two years of the pipeline becoming operational, Williams will have the option to increase its ownership up to 50 percent by reimbursing us for its proportionate share of all construction costs. If Williams exercises its option to increase its ownership to the full 50 percent, Williams would have the option to become operator. This project has received the required approvals of various state and federal regulatory authorities, and we are constructing the pipeline with start-up currently scheduled for the second quarter of 2008.

As part of a long-term agreement, Williams dedicated its NGL production from two of its natural gas processing plants in Wyoming to the joint-venture company. We will provide downstream fractionation, storage and transportation services to Williams. The pipeline project is currently estimated to cost approximately $535 million, excluding AFUDC. In addition, we are investing approximately $216 million, excluding AFUDC, to expand our existing fractionation and storage capabilities and the capacity of our natural gas liquids distribution pipelines. Financing for both projects may include a combination of short- or long-term debt or equity.

The ONEOK Transactions - In April 2006, we completed the acquisition and consolidated certain companies comprising ONEOK's former gathering and processing, natural gas liquids, and pipelines and storage segments (collectively, the ONEOK Energy Assets) in a series of transactions (collectively, the ONEOK Transactions). As part of the ONEOK Transactions, ONEOK acquired ONEOK NB, formerly known as Northwest Border Pipeline Company, an affiliate of TransCanada that held a 0.35 percent general partner interest in us, under a Purchase and Sale Agreement between an affiliate of ONEOK and an affiliate of TransCanada. As a result, ONEOK owns our entire 2 percent general partner interest and controls us.

We acquired the ONEOK Energy Assets for approximately $3 billion, including $1.35 billion in cash, before adjustments, and approximately 36.5 million Class B limited partner units. The Class B limited partner units and the related general partner interest contribution were valued at approximately $1.65 billion. ONEOK now owns approximately 37.0 million of our limited partner units, which, when combined with its general partner interest, increased its total interest in us to approximately 45.7 percent. We used $1.05 billion drawn under our $1.1 billion, 364-day credit agreement (the Bridge Facility), coupled with the proceeds from the sale of a 20 percent partnership interest in Northern Border Pipeline, to finance the cash portion of the transaction.

In June 2005, the FASB ratified the consensus reached in EITF Issue No. 04-5, "Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights" (EITF 04-5). EITF 04-5 presumes that a general partner controls a limited partnership and therefore should consolidate the partnership in the financial statements of the general partner. Our Partnership Agreement provides for the right to replace the general partner by a vote of 66-$^{2}/_{3}$ percent of the outstanding units, excluding units held by the general partner and its affiliates. Under the guidance in EITF 04-5, ONEOK is deemed to have control for accounting purposes. ONEOK elected to use the prospective method and began to consolidate our operations in their consolidated financial statements as of January 1, 2006. As ONEOK is deemed to control us under the requirements of EITF 04-5, the ONEOK Transactions were accounted for as a transaction between entities under common control and these transactions were excluded from the accounting prescribed by Statement 141, "Business Combinations." Accordingly, ONEOK's historical cost basis in the ONEOK Energy Assets was transferred to us in a manner similar to a pooling of interests. The difference between the historical cost basis of the net assets acquired of $2.7 billion and the cash paid was assigned to the value of the Class B limited partner units issued to ONEOK and its general partner interest in us. These assets and their related operations are included in our consolidated financial statements retroactive to January 1, 2006.

Since the ONEOK Transactions were not completed until April 2006, the income and cash flow from the ONEOK Energy Assets for the first quarter of 2006 were retained by ONEOK. In our 2006 Consolidated Statement of Cash Flows, we reported cash flow retained by ONEOK of $177.5 million, which represents the cash flows generated from these companies while they were owned by ONEOK.

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The following table shows the impact to our Consolidated Statements of Income for the ONEOK Energy Assets prior to our acquisition.

ONEOK Energy Assets		**Three Months Ended March 31, 2006**
		(Thousands of dollars)
Operating revenue	$	1,162,571
Cost of sales and fuel		1,013,851
Net margin		148,720
Operating expenses:		
Operations and maintenance		47,530
Depreciation and amortization		19,277
Taxes other than income		4,407
Total operating expenses		71,214
Operating income		77,506
Interest expense		21,281
Other income, net		1,760
Income from continuing operations before income taxes		57,985
Income taxes		22,167
Net income	$	35,818
Limited partners’ interest in net income:		
Net income	$	35,818
General partner interest in net income		(35,818)
Limited partners’ interest in net income	$	-

Prior to the acquisition, the ONEOK Energy Assets were included in the consolidated state and federal income tax returns of ONEOK and, accordingly, current taxes payable were allocated to the ONEOK Energy Assets based on ONEOK’s effective tax rate. Income tax liabilities and provisions for income tax expense for the ONEOK Energy Assets were calculated on a stand-alone basis. Our Consolidated Statements of Income for 2006 includes income tax expense recorded for the ONEOK Energy Assets of $22.2 million for the first quarter of 2006. In conjunction with the ONEOK Transactions, all income tax liabilities of ONEOK Energy Assets at the time of the ONEOK Transactions were retained by ONEOK.

Income from the ONEOK Energy Assets for the first quarter of 2006 also reflects interest expense of $21.3 million, which represents interest charged on long-term debt owed to ONEOK. The interest rate on the debt was calculated periodically based upon ONEOK’s weighted average cost of debt. This debt was retained by ONEOK as part of the ONEOK Transactions.

Under the terms of the ONEOK Transactions, we recorded a $72.6 million purchase price adjustment related to a finalized working capital settlement. The working capital settlement is reflected as an increase to the value of the Class B units and was approved by our Audit Committee.

The unaudited pro forma information in the table below presents a summary of our results of operations as if the acquisition of the ONEOK Energy Assets had occurred at the beginning of the periods presented. The results do not necessarily reflect the results that would have been obtained if the acquisition of the ONEOK Energy Assets had actually occurred on the dates indicated or results that may be expected in the future.

		Pro Forma Year Ended December 31, 2005
		(Thousands of dollars)
Revenue	$	4,102,335
Income from continuing operations	$	314,471
Net income per unit	$	3.51

The units issued to ONEOK were the newly created Class B limited partner units. As of April 7, 2007, the Class B limited partner units are no longer subordinated to distributions on our common units and generally have the same voting rights as our common units.

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At a special meeting of the holders of our common units held March 29, 2007, the unitholders approved a proposal to permit the conversion of all or a portion of the Class B limited partner units issued in the ONEOK Transactions into common units on a one-for-one basis at the option of the Class B unitholder. The March 29, 2007, special meeting was adjourned to May 10, 2007, to allow unitholders additional time to vote on an additional proposal to approve amendments to our Partnership Agreement, which, had the amendments been approved, would have granted voting rights for units held by our general partner and its affiliates if a vote was held to remove our general partner and would have required fair market value compensation for the general partner interest if the general partner was removed. While a majority of our common unitholders voted in favor of the proposed amendments to our Partnership Agreement at the reconvened meeting of our common unitholders held May 10, 2007, the proposed amendments were not approved by the required two-thirds affirmative vote of our outstanding units, excluding the common units and Class B limited partner units held by ONEOK and its affiliates. As a result, effective April 7, 2007, the Class B limited partner units are entitled to receive increased quarterly distributions equal to 110 percent of the distributions paid with respect to our common units.

On June 21, 2007, ONEOK, as the sole holder of our Class B limited partner units, waived its right to receive the increased quarterly distributions on the Class B units for the period of April 7, 2007, through December 31, 2007, and continuing thereafter until ONEOK gives us no less than 90 days advance notice that it has withdrawn its waiver. Any such withdrawal of the waiver will be effective with respect to any distribution on the Class B units declared or paid on or after the 90 days following delivery of the notice.

In addition, since the proposed amendments to our Partnership Agreement were not approved by our common unitholders, if our common unitholders vote at any time to remove ONEOK or its affiliates as our general partner, quarterly distributions payable on the Class B limited partner units would increase to 123.5 percent of the distributions payable with respect to the common units, and distributions payable upon liquidation of the Class B limited partner units would increase to 123.5 percent of the distributions payable with respect to the common units.

Disposition of 20 Percent Partnership Interest in Northern Border Pipeline - In April 2006, we completed the sale of a 20 percent partnership interest in Northern Border Pipeline to TC PipeLines for approximately $297 million to help finance the acquisition of the ONEOK Energy Assets. We recorded a gain on the sale of approximately $113.9 million in the second quarter of 2006. We and TC PipeLines each now own a 50 percent interest in Northern Border Pipeline, and an affiliate of TransCanada became the operator of the pipeline in April 2007. Under Statement 94, "Consolidation of All Majority Owned Subsidiaries," a majority-owned subsidiary is not consolidated if control is likely to be temporary or if it does not rest with the majority owner. Neither we nor TC PipeLines has control of Northern Border Pipeline, as control is shared equally through Northern Border Pipeline's Management Committee. Our interest in Northern Border Pipeline has been accounted for as an investment under the equity method applied on a retroactive basis to January 1, 2006.

Acquisition of Guardian Pipeline Interests - In April 2006, we acquired the 66- $^{2}/_{3}$ percent interest in Guardian Pipeline not previously owned by us for approximately $77 million, increasing our ownership interest to 100 percent. We used borrowings from our credit facility to fund the acquisition of the additional interest in Guardian Pipeline. Following the completion of the transaction, we consolidated Guardian Pipeline in our consolidated financial statements. This change was accounted for on a retroactive basis to January 1, 2006.

C. DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

We utilize financial instruments to reduce our market risk exposure to interest rate and commodity price fluctuations, and to achieve more predictable cash flows. We follow established policies and procedures to assess risk and approve, monitor and report our financial instrument activities. We do not use these instruments for trading purposes.

Cash Flow Hedges - Our Natural Gas Gathering and Processing segment periodically enters into commodity derivative contracts and fixed-price physical contracts. Our Natural Gas Gathering and Processing segment primarily utilizes NYMEX-based futures, collars and over-the-counter swaps, which are designated as cash flow hedges, to hedge its exposure to volatility in the price of natural gas, NGLs and condensate and the gross processing spread. At December 31, 2007, the accompanying Consolidated Balance Sheet reflected an unrealized loss of $16.4 million in accumulated other comprehensive income (loss), with a corresponding offset in derivative financial instrument assets and liabilities, all of which will be recognized over the next 12 months. Net gains and losses related to the ineffective portion of our hedges are reclassified out of accumulated other comprehensive income (loss) to operating revenues in the period the ineffectiveness occurs. Ineffectiveness related to these cash flow hedges was not material in 2007 or 2005. Ineffectiveness related to these cash flow hedges resulted in a gain of approximately $4.5 million for 2006. There were no gains or losses during 2007, 2006 or 2005 due to the discontinuance of cash flow hedge treatment.

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Fair Value Hedges - In 2007 and prior years we terminated various interest rate swap agreements. The net savings from the termination of these swaps is being recognized in interest expense over the terms of the debt instruments originally hedged. Net interest expense savings for 2007 for all terminated swaps was $3.7 million, and the remaining net savings for all terminated swaps will be recognized over the following periods.

	(Millions of dollars)	
2008	$	3.7
2009		3.7
2010		3.7
2011		0.9
2012		-
Thereafter		-

At December 31, 2007, none of the interest on our fixed-rate debt was swapped to floating using interest-rate swaps.

D. GOODWILL AND INTANGIBLE ASSETS

Goodwill

Activity - There was no change in the carrying amounts of goodwill during 2007. The following table reflects the changes in the carrying amount of goodwill for the period indicated.

	Balance December 31, 2005	Additions	Adjustments	Balance December 31, 2006
	(Thousands of dollars)			
Natural Gas Gathering and Processing	$ 75,532	$ 14,505	$ -	$ 90,037
Natural Gas Pipelines	68,872	60,125	-	128,997
Natural Gas Liquids Gathering and Fractionation	-	175,566	-	175,566
Other	8,378	-	(8,378)	-
Goodwill	$ 152,782	$ 250,196	$ (8,378)	$ 394,600

The acquisition of the ONEOK Energy Assets resulted in $214.8 million of additional goodwill on our 2006 Consolidated Balance Sheet.

Our acquisition of the 66- 2/3 percent interest in Guardian Pipeline not previously owned by us resulted in the recognition of $5.7 million of additional goodwill and reclassification of $1.7 million to goodwill, which had been previously included in our investment in unconsolidated affiliates.

Goodwill increased by approximately $27.9 million in 2006 relating to the 2003 acquisition of Viking Gas Transmission. In our accounting for the acquisition, we had allocated the entire purchase price to the fair value of the tangible assets including plant in service. Since that date, we have determined that the amount of purchase price representing a premium over Viking Gas Transmission's historic rate base is not being recovered in its rates and, accordingly, should be accounted for as goodwill under Statement 142.

See Black Mesa section of this Note for discussion of goodwill impairment.

Equity Method Goodwill - For the investments we account for under the equity method, the premium or excess cost over underlying fair value of net assets is referred to as equity method goodwill. Investment in unconsolidated affiliates on our accompanying Consolidated Balance Sheets includes equity method goodwill of $185.6 million as of December 31, 2007 and 2006.

Impairment Test - We apply the provisions of Statement 142, "Goodwill and Other Intangible Assets," and perform our annual impairment test on July 1. There were no impairment charges resulting from the July 1, 2007, impairment testing, and no events indicating an impairment have occurred subsequent to that date.

Black Mesa - Black Mesa, which is included in our Other segment, includes a pipeline that was designed to transport crushed coal suspended in water along 273 miles of pipeline that originates at a coal mine in Kayenta, Arizona, and terminates at Mohave Generating Station (Mohave) in Laughlin, Nevada. The coal slurry pipeline was the sole source of fuel for Mohave

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and was fully contracted to Peabody Western Coal until December 31, 2005. The water used by the coal slurry pipeline was supplied from an aquifer in the Navajo Nation and Hopi Tribe joint-use area until December 31, 2005.

Under a consent decree, Mohave agreed to install pollution control equipment by December 2005. However, due to the uncertainty surrounding ongoing water and coal supply negotiations, Southern California Edison Company (SCE), a 56 percent owner of Mohave, filed a petition before the California Public Utilities Commission (CPUC) requesting that they either recognize the end of Mohave's coal-fired operations on December 31, 2005, or authorize expenditures for pollution control activities required for future operation. In December 2004, the CPUC authorized SCE to make the necessary expenditures for critical path investments and directed interested parties to continue working toward resolution of essential water and coal supply issues.

On December 31, 2005, Black Mesa's transportation contract with the coal supplier of Mohave expired, and our coal slurry pipeline operations were shut down. In June 2006, SCE completed a comprehensive study of the water source, coal supply and transportation issues, and announced that it would no longer pursue the resumption of plant operations. In February 2007, another Mohave co-owner, Salt River Project, announced it was ending its efforts to return the plant to service. We plan to either divest the Black Mesa pipeline or commence decommissioning of the pipeline during 2008.

During 2006, we reassessed our coal slurry pipeline operation as a result of the developments described above. We concluded that the likelihood of Black Mesa resuming operations was significantly reduced, and a goodwill and asset impairment of $8.4 million and $3.6 million, respectively, was recorded as depreciation and amortization. The reduction to net income after income taxes was $10.6 million.

Intangible Assets

Our intangible assets primarily relate to contracts acquired through the acquisition of the natural gas liquids businesses from ONEOK and are being amortized over an aggregate weighted-average period of 40 years. Amortization expense for both 2007 and 2006 was $7.7 million, and the aggregate amortization expense for each of the next five years is estimated to be approximately $7.7 million. The following tables reflect the gross carrying amount and accumulated amortization of intangible assets for the periods presented.

	December 31, 2007		
	Gross Intangible Assets	**Accumulated Amortization**	**Net Intangible Assets**
	(Thousands of dollars)		
Natural Gas Liquids Gathering and Fractionation	**$ 292,000**	**$ (18,249)**	**$ 273,751**
Natural Gas Liquids Pipelines	**14,650**	**(917)**	**13,733**
Intangible Assets	**$ 306,650**	**$ (19,166)**	**$ 287,484**

	December 31, 2006		
	Gross Intangible Assets	**Accumulated Amortization**	**Net Intangible Assets**
	(Thousands of dollars)		
Natural Gas Liquids Gathering and Fractionation	$ 292,000	$ (10,949)	$ 281,051
Natural Gas Liquids Pipelines	14,650	(550)	14,100
Intangible Assets	$ 306,650	$ (11,499)	$ 295,151

E. PARTNERS' EQUITY

At December 31, 2007, we had 46,397,214 common units and 36,494,126 Class B Units issued and outstanding. ONEOK owns all of the Class B Units, approximately 500,000 common units, and the 2 percent general partner interest in us. The Class B Units, common units and the general partner interest held by ONEOK and its affiliates together constitute a 45.7 percent interest in us.

Under our Partnership Agreement, in conjunction with the issuance of additional common units, our general partner is required to make equity contributions to us in order to maintain a 2 percent general partner interest.

Under our Partnership Agreement, we make distributions to our partners with respect to each calendar quarter in an amount equal to 100 percent of our available cash within 45 days following the end of each quarter. Available cash generally consists of all our cash receipts adjusted for our cash disbursements and net changes to cash reserves. Available cash will

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generally be distributed 98 percent to limited partners and 2 percent to our general partner. As an incentive, the general partner's percentage interest in quarterly distributions is increased after certain specified target levels are met. Under the incentive distribution provisions, the general partner receives:

- 15 percent of amounts distributed in excess of $0.605 per common unit,
- 25 percent of amounts distributed in excess of $0.715 per unit, and
- 50 percent of amounts distributed in excess of $0.935 per unit.

Our income is allocated to the general partner and the limited partners in accordance with their respective partnership percentages, after giving effect to any priority income allocations for incentive distributions that are allocated to the general partner. For the years ended December 31, 2007, 2006 and 2005, incentive distributions allocated to the general partners totaled $50.6 million, $31.6 million and $8.0 million, respectively.

F. CREDIT FACILITIES

2007 Partnership Credit Agreement - In March 2007, we amended and restated our revolving credit facility agreement (2007 Partnership Credit Agreement) with several banks and other financial institutions and lenders in the following principal ways: (i) revised the pricing, (ii) extended the maturity by one year to March 2012, (iii) eliminated the interest coverage ratio covenant, (iv) increased the permitted ratio of indebtedness to EBITDA to 5 to 1 (from 4.75 to 1), (v) increased the swingline sub-facility commitments from $15 million to $50 million and (vi) changed the permitted amount of subsidiary indebtedness from $35 million to 10 percent of our consolidated indebtedness. The interest rates applicable to extensions of credit under this agreement are based, at our election, on either (i) the higher of prime or one-half of one percent above the Federal Funds Rate, which is the rate that banks charge each other for the overnight borrowing of funds, or (ii) the Eurodollar rate plus a set number of basis points, depending on our current long-term unsecured debt ratings.

In July 2007, we exercised the accordion feature of our 2007 Partnership Credit Agreement to increase the commitment amounts by $250 million to a total of $1.0 billion.

In December 2006, we amended our 2007 Partnership Credit Agreement (previously referred to as the 2006 Partnership Credit Agreement). This agreement now provides for the exclusion of hybrid securities from debt in an amount not to exceed 15 percent of total capitalization when calculating the leverage ratio. Material projects may now be approved by the administrative agent as opposed to requiring approval from 50 percent of the lenders. The methodology of making pro forma adjustments to EBITDA (net income before interest expense, income taxes and depreciation and amortization) that is used in the calculation of the financial covenants with respect to approved material projects was also amended. The amendment excluded the Overland Pass Pipeline Company agreement from the covenant that limits our ability to enter into agreements that restrict our ability to grant liens to the lenders under the 2007 Partnership Credit Agreement.

Under the 2007 Partnership Credit Agreement, we are required to comply with certain financial, operational and legal covenants. Among other things, these requirements include maintaining a ratio of indebtedness to adjusted EBITDA (EBITDA adjusted for any approved capital projects) of no more than 5 to 1. If we consummate one or more acquisitions in which the aggregate purchase price is $25 million or more, the allowable ratio of indebtedness to adjusted EBITDA will be increased to 5.5 to 1 for the three calendar quarters following the acquisition.

Upon breach of any covenant, discussed above, amounts outstanding under the 2007 Partnership Credit Agreement may become immediately due and payable. We were in compliance with these covenants at December 31, 2007. The average interest rate of borrowings under this agreement was 5.40 percent and 6.75 percent at December 31, 2007 and 2006, respectively. At December 31, 2007, we had $100 million of borrowings outstanding under this agreement and $900 million was available.

In November 2007, we entered into a $15 million Senior Unsecured Letter of Credit Facility and Reimbursement Agreement with Wells Fargo Bank, N.A., of which $12 million is being used, and a $12 million Standby Letter of Credit Agreement with Royal Bank of Canada. Both agreements are used to support various permits required by the KDHE for our ongoing business in Kansas.

We had $10 million in letters of credit outstanding at December 31, 2006.

Bridge Facility - In April 2006, we entered into a $1.1 billion 364-day credit agreement (the Bridge Facility) with a syndicate of banks and borrowed $1.05 billion to finance a portion of the acquisition of the ONEOK Energy Assets. In September 2006, we repaid the amounts outstanding under the Bridge Facility using proceeds from the issuance of senior notes, which resulted in the Bridge Facility being terminated in accordance with its terms. See Note G for further discussion regarding the issuance of senior notes.

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Guardian Pipeline - The Guardian Pipeline revolving credit agreement permitted us to choose rates based on the prime commercial lending rate or LIBOR as the interest rate on its outstanding borrowings, specify the portion of the borrowings to be covered by specific interest rate options and specify the interest rate period. The Guardian Pipeline revolving credit agreement terminated in November 2007.

G. LONG-TERM DEBT

The following table sets forth our long-term debt for the periods indicated. All notes are senior unsecured obligations, ranking equally in right of payment with all of our existing and future unsecured senior indebtedness.

	December 31, 2007	December 31, 2006
	(Thousands of dollars)	
ONEOK Partners		
$250,000 at 8.875% due 2010	**$ 250,000**	$ 250,000
$225,000 at 7.10% due 2011	**225,000**	225,000
$350,000 at 5.90% due 2012	**350,000**	350,000
$450,000 at 6.15% due 2016	**450,000**	450,000
$600,000 at 6.65% due 2036	**600,000**	600,000
$600,000 at 6.85% due 2037	**600,000**	-
	2,475,000	1,875,000
Guardian Pipeline		
Average 7.85% due 2022	**133,641**	145,572
Total long-term notes payable	**2,608,641**	2,020,572
Change in fair value of hedged debt	**12,155**	12,310
Unamortized debt premium	**(3,470)**	(1,353)
Current maturities	**(11,930)**	(11,931)
Long-term debt	**$ 2,605,396**	$ 2,019,598

The aggregate maturities of long-term debt outstanding for years 2008 through 2012 are shown below.

	ONEOK Partners	Guardian Pipeline	Total
	(Millions of dollars)		
2008	$ -	$ 11.9	$ 11.9
2009	-	11.9	11.9
2010	250.0	11.9	261.9
2011	225.0	11.9	236.9
2012	350.0	11.1	361.1

2007 Debt Issuance - In September 2007, we completed an underwritten public offering of $600 million aggregate principal amount of 6.85 percent Senior Notes due 2037 (the 2037 Notes). The 2037 Notes were issued under our existing shelf registration statement filed with the SEC.

We may redeem the 2037 Notes, in whole or in part, at any time prior to their maturity at a redemption price equal to the principal amount of the 2037 Notes, plus accrued and unpaid interest and a make-whole premium. The redemption price will never be less than 100 percent of the principal amount of the 2037 Notes plus accrued and unpaid interest. The 2037 Notes are senior unsecured obligations, ranking equally in right of payment with all of our existing and future unsecured senior indebtedness, and effectively junior to all of the existing debt and other liabilities of our non-guarantor subsidiaries. The 2037 Notes are non-recourse to our general partner.

The net proceeds from the 2037 Notes, after deducting underwriting discounts and commissions and expenses, of $592.9 million were used to finance our $300 million acquisition, before working capital adjustments, of an interstate natural gas liquids and refined petroleum products pipeline system and related assets from a subsidiary of Kinder Morgan and to repay debt outstanding under the 2007 Partnership Credit Agreement.

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The terms of the 2037 Notes are governed by the Indenture, dated as of September 25, 2006, between ONEOK Partners and Wells Fargo Bank, N.A., as trustee, as supplemented by the Fourth Supplemental Indenture, dated September 28, 2007 (Indenture). The Indenture does not limit the aggregate principal amount of debt securities that may be issued and provides that debt securities may be issued from time to time in one or more additional series. The Indenture contains covenants including, among other provisions, limitations on our ability to place liens on our property or assets and sell and lease back our property.

The 2037 Notes will mature on October 15, 2037. We will pay interest on the 2037 Notes on April 15 and October 15 of each year. The first payment of interest on the 2037 Notes will be made on April 15, 2008. Interest on the 2037 Notes accrues from September 28, 2007, which was the issuance date of the 2037 Notes.

2006 Debt Issuance - In September 2006, we completed an underwritten public offering of (i) $350 million aggregate principal amount of 5.90 percent Senior Notes due 2012 (the 2012 Notes), (ii) $450 million aggregate principal amount of 6.15 percent Senior Notes due 2016 (the 2016 Notes) and (iii) $600 million aggregate principal amount of 6.65 percent Senior Notes due 2036 (the 2036 Notes and collectively with the 2012 Notes and the 2016 Notes, the Notes). We registered the sale of the Notes with the SEC pursuant to a shelf registration statement filed on September 19, 2006.

We may redeem the Notes, in whole or in part, at any time prior to their maturity at a redemption price equal to the principal amount of the Notes, plus accrued interest and a make-whole premium. The redemption price will never be less than 100 percent of the principal amount of the relevant Notes plus accrued and unpaid interest. The Notes are senior unsecured obligations, ranking equally in right of payment with all of our existing and future unsecured senior indebtedness, and effectively junior to all of the existing and future debt and other liabilities of our non-guarantor subsidiaries. The Notes are non-recourse to our general partner.

The net proceeds from the Notes of approximately $1.39 billion, after deducting underwriting discounts and commissions and expenses but before offering expenses, were used to repay all of the $1.05 billion outstanding under our Bridge Facility and to repay $335 million of indebtedness outstanding under the 2006 Partnership Credit Agreement. The terms of the Notes are governed by the Indenture, dated September 25, 2006, between us and Wells Fargo Bank, N.A., as trustee, as supplemented by the First Supplemental Indenture (with respect to the 2012 Notes), the Second Supplemental Indenture (with respect to the 2016 Notes) and the Third Supplemental Indenture (with respect to the 2036 Notes), each dated September 25, 2006. The Indenture does not limit the aggregate principal amount of debt securities that may be issued and provides that debt securities may be issued from time to time in one or more additional series. The Indenture contains covenants including, among other provisions, limitations on our ability to place liens on our property or assets, and sell and lease back our property.

The 2012 Notes, 2016 Notes and 2036 Notes will mature on April 1, 2012, October 1, 2016 and October 1, 2036, respectively. We will pay interest on the Notes on April 1 and October 1 of each year. The first payment of interest on the Notes was made on April 1, 2007. Interest on the Notes accrued from September 25, 2006, which was the issuance date of the Notes.

Debt Covenants - We have debt covenants in addition to the covenants discussed in "2007 Debt Issuance" and "2006 Debt Issuance" above. Our $250 million and $225 million long-term notes payable, due 2010 and 2011, respectively, contain provisions that require us to offer to repurchase the senior notes at par value if our Moody's or S&P credit rating falls below investment grade (Baa3 for Moody's or BBB- for S&P) and the investment grade rating is not reinstated within a period of 40 days. Further, the indentures governing our senior notes due 2010 and 2011 include an event of default upon acceleration of other indebtedness of $25 million or more and the indentures governing our senior notes due 2012, 2016, 2036 and 2037 include an event of default upon the acceleration of other indebtedness of $100 million or more that would be triggered by such an offer to repurchase. Such an event of default would entitle the trustee or the holders of 25 percent in aggregate principal amount of the outstanding senior notes due 2010, 2011, 2012, 2016, 2036 and 2037 to declare those notes immediately due and payable in full.

Debt Guarantee - The 2037 Notes and the Notes are fully and unconditionally guaranteed on a senior unsecured basis by the Intermediate Partnership. The guarantee ranks equally in right of payment to all of the Intermediate Partnership's existing and future unsecured senior indebtedness. We have no significant assets or operations other than our investment in our wholly owned subsidiary, the Intermediate Partnership, which is also consolidated. The Intermediate Partnership holds partnership interests and the equity in our subsidiaries as well as a 50 percent interest in Northern Border Pipeline at December 31, 2007, which is accounted for under the equity method.

The Northern Border Pipeline partnership agreement provides that distributions to Northern Border Pipeline's partners are to be made on a pro rata basis according to each partner's percentage interest. The Northern Border Pipeline Management Committee determines the amount and timing of such distributions. Any changes to, or suspension of, the cash distribution

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policy of Northern Border Pipeline requires the unanimous approval of the Northern Border Pipeline Management Committee. Cash distributions are equal to 100 percent of distributable cash flow as determined from Northern Border Pipeline's financial statements based upon earnings before interest, taxes, depreciation and amortization less interest expense and maintenance capital expenditures. Loans or other advances from Northern Border Pipeline to its partners or affiliates are prohibited under its credit agreement. After we completed the sale of a 20 percent partnership interest in Northern Border Pipeline to TC PipeLines in April 2006, the Northern Border Pipeline Management Committee adopted certain changes to its cash distribution policy related to financial ratio targets and capital contributions. The change was to define minimum equity to total capitalization ratios to be used by the Northern Border Pipeline Management Committee to establish the timing and amount of required capital contributions. In addition, any shortfall due to the inability to refinance maturing debt will be funded by capital contributions. At December 31, 2007 and 2006, our equity in the net assets of Northern Border Pipeline was approximately $419 million and $438 million, respectively.

Guardian Pipeline Senior Notes - These notes were issued under a master shelf agreement with certain financial institutions. Principal payments are due annually through 2022. Interest rates on the $133.6 million in notes outstanding at December 31, 2007, range from 7.61 percent to 8.27 percent, with an average rate of 7.85 percent. Guardian Pipeline's senior notes contain financial covenants that require the maintenance of a ratio of (1) EBITDAR (net income plus interest expense, income taxes, operating lease expense and depreciation and amortization) to the sum of interest expense plus operating lease expense of not less than 1.5 to 1 and (2) total indebtedness to EBITDAR of not greater than 5.75 to 1. Upon any breach of these covenants, all amounts outstanding under the master shelf agreement may become due and payable immediately. At December 31, 2007, Guardian Pipeline was in compliance with its financial covenants.

Other

Fair Value - The following estimated fair values represent the amount at which debt could be exchanged in a current transaction between willing parties. Based on quoted market prices for similar issues with similar terms and remaining maturities, the estimated fair value of the aggregate of all the senior notes outstanding was approximately $2.7 billion and $2.0 billion at December 31, 2007 and 2006, respectively. We presently intend to maintain the current schedule of maturities for the senior notes, which will result in no gains or losses on their respective repayment. The fair value of the 2007 Partnership Credit Agreement approximates the carrying value since the interest rates are periodically adjusted to reflect current market conditions.

Unamortized Debt Premium, Discount and Expense - We amortize premiums, discounts and expenses incurred in connection with the issuance of long-term debt consistent with the terms of the respective debt instrument.

H. COMMITMENTS AND CONTINGENCIES

Operating Leases - Future minimum lease payments under non-cancelable operating leases on a gas processing plant, storage contracts, office space, pipeline equipment, rights-of-way and vehicles are shown in the table below.

	(Millions of dollars)
2008	$ 18.7
2009	13.8
2010	12.7
2011	12.6
2012	5.8

Firm Transportation Obligations and Other Commitments - We have firm transportation agreements with Fort Union Gas Gathering and Lost Creek Gathering Company. The Fort Union Gas Gathering agreement expires in 2009, and the Lost Creek Gathering Company agreement expires in 2010. Under these agreements, we must make specified minimum payments to Fort Union Gas Gathering and Lost Creek Gathering Company each month. We recorded expenses of $11.9 million, $12.0 million and $11.7 million for 2007, 2006 and 2005, respectively, related to these agreements. At December 31, 2007, the estimated aggregate amounts of such required future payments were $11.9 million for 2008, $11.3 million for 2009 and $3.7 million for 2010.

Environmental Liabilities - We are subject to multiple environmental laws and regulations affecting many aspects of our present and future operations, including air emissions, water quality, wastewater discharges, solid wastes and hazardous materials, and substance management. These laws and regulations generally require us to obtain and comply with a wide variety of environmental registrations, licenses, permits, inspections and other approvals. Failure to comply with these laws, regulations, permits and licenses may expose us to fines, penalties and/or interruptions in our operations that could be

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material to our results of operations. If an accidental leak or spill of hazardous materials occurs from our lines or facilities, in the process of transporting natural gas, NGLs, or refined products, or at any facility that we own, operate or otherwise use, we could be held jointly and severally liable for all resulting liabilities, including investigation and clean-up costs, which could materially affect our results of operations and cash flows. In addition, emission controls required under the federal Clean Air Act and other similar federal and state laws could require unexpected capital expenditures at our facilities. We cannot assure that existing environmental regulations will not be revised or that new regulations will not be adopted or become applicable to us. Revised or additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from customers, could have a material adverse effect on our business, financial condition and results of operations.

Our expenditures for environmental evaluation and remediation to date have not been significant in relation to our results of operations, and there were no material effects upon earnings during 2007, 2006 or 2005 related to compliance with environmental regulations.

Legal Proceedings - We are a party to various litigation matters and claims that are in the normal course of our operations. While the results of litigation and claims cannot be predicted with certainty, we believe the final outcome of such matters will not have a material adverse effect on our consolidated results of operations, financial position or liquidity.

Other - As a result of an internal review of a transaction that was brought to the attention of one of our affiliates by a third party, we have commenced an internal review of transactions that may have violated FERC capacity release rules or related rules. We have notified the FERC of this review and expect to file a report with the FERC by mid-March 2008 concerning any violations. At this time, we do not believe that penalties, if any, associated with potential violations will have a material impact on our results of operations, financial position or liquidity.

I. INCOME TAXES

Components of the income tax provision applicable to continuing operations and income taxes paid by our corporate subsidiaries are shown in the table below.

	Years Ended December 31,		
	2007	**2006**	**2005**
	(Thousands of dollars)		
Taxes currently payable:			
Federal	**$ 72**	$ -	$ 2,036
State	**4,203**	-	390
Total taxes currently payable	**4,275**	-	2,426
Deferred taxes:			
Federal	**3,994**	2,163	2,639
State	**573**	3,339	727
Total deferred taxes	**4,567**	5,502	3,366
Taxes retained by ONEOK	**-**	22,167	-
Total tax provision	**$ 8,842**	$ 27,669	$ 5,792

Taxes retained by ONEOK represent taxes accrued for the ONEOK Energy Assets during the first quarter of 2006. In conjunction with the ONEOK Transactions, all income tax liabilities of the ONEOK Energy Assets at the time of the ONEOK Transactions were retained by ONEOK. See Note B for additional discussion of the ONEOK Transactions.

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The following table is a reconciliation of our provision for income taxes for the periods indicated.

	Years Ended December 31,		
	2007	**2006**	**2005**
	(Thousands of dollars)		
Pretax income from continuing operations	**$ 416,589**	$ 420,849	$ 152,299
Federal statutory income tax rate	**35.0%**	35.0%	35.0%
Provision for federal income taxes	**145,806**	147,297	53,305
Partnership earnings not subject to tax	**(141,884)**	(144,928)	(48,630)
State income taxes	**4,772**	2,990	1,117
Other, net	**148**	143	-
Income tax expense	**$ 8,842**	$ 5,502	$ 5,792

The following table sets forth the tax effects of temporary differences that gave rise to significant portions of the deferred tax assets and liabilities for the periods indicated.

	Years Ended December 31,	
	2007	**2006**
	(Thousands of dollars)	
Deferred tax assets:		
Net operating losses	**$ 4,715**	$ 7,971
Other	**1,596**	129
Total deferred tax assets	**6,311**	8,100
Deferred tax liabilities:		
Excess of tax over book depreciation and depletion	**7,934**	5,414
Regulatory assets	**2,544**	2,526
Other	**77**	79
Total deferred tax liabilities	**10,555**	8,019
Net deferred tax assets/ (liabilities)	**$ (4,244)**	$ 81

At December 31, 2007, we had approximately $5.0 million of tax benefits available related to net operating loss carryforwards, which will expire between the years 2022 and 2026. We believe that it is more likely than not that the tax benefits of the net operating loss carryforwards will be utilized prior to their expiration; therefore, no valuation allowance is necessary.

We had income taxes payable of approximately $3.1 million at December 31, 2007. Cash paid for income taxes, net, was approximately $1.0 million, $0.6 million and $1.4 million at December 31, 2007, 2006 and 2005, respectively.

J. SEGMENTS

Segment Descriptions - In July 2007, we announced a series of organizational changes that led to the realignment of our previous business segments. Our financial results are now reported in these four segments: (i) Natural Gas Gathering and Processing, which remains unchanged, (ii) Natural Gas Pipelines, which is comprised of our former interstate natural gas pipelines segment and the natural gas assets of our former pipelines and storage segment, (iii) Natural Gas Liquids Gathering and Fractionation, which remains unchanged, and (iv) Natural Gas Liquids Pipelines, which is comprised of the natural gas liquids assets of our former pipelines and storage segment. Prior periods have been restated to reflect these segment changes.

Our operations are divided into these strategic business segments based on similarities in economic characteristics, products and services, types of customers, methods of distribution and regulatory environment, as follows:

- our Natural Gas Gathering and Processing segment primarily gathers and processes raw natural gas,
- our Natural Gas Pipelines segment primarily operates regulated interstate and intrastate natural gas transmission pipelines and natural gas storage facilities,
- our Natural Gas Liquids Gathering and Fractionation segment primarily gathers, treats and fractionates NGLs and stores and markets NGL products, and
- our Natural Gas Liquids Pipelines segment primarily operates our FERC-regulated interstate natural gas liquids gathering and distribution pipelines.

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The acquisition of the ONEOK Energy Assets in April 2006 is accounted for in our consolidated financial statements effective January 1, 2006. In connection with these transactions, we formed our former natural gas liquids segment and our former pipelines and storage segment.

Accounting Policies - The accounting policies of the segments are described in Note A. Intersegment and affiliate sales are recorded on the same basis as sales to unaffiliated customers. Our Natural Gas Gathering and Processing segment sells natural gas to ONEOK and its subsidiaries. A portion of our Natural Gas Pipelines segment's revenues are from ONEOK and its subsidiaries that utilize transportation and storage services. Corporate overhead costs relating to a reportable segment have been allocated for the purpose of calculating operating income. Our equity method investments do not represent operating segments.

Northern Border Pipeline was no longer consolidated effective January 1, 2006. For our Natural Gas Pipelines segment, Northern Border Pipeline's revenues represented approximately 85 percent of the segment's revenues in 2005.

Customers - The main customers for our Natural Gas Gathering and Processing segment are primarily major and independent oil and gas production companies. Our Natural Gas Liquids Gathering and Fractionation segment's customers are primarily natural gas gathering and processing companies and petrochemical, refining and NGL marketing companies. Companies served by our Natural Gas Pipelines segment include local distribution companies, power generating companies, natural gas marketing companies and petrochemical companies. Our Natural Gas Liquids Pipelines segment's customers are primarily NGL gathering companies, propane distributors and petrochemical and refining companies.

In 2007 and 2006, we had no single external customer from which we received 10 percent or more of our consolidated revenues. For 2005, we had two customers that accounted for more than 10 percent of our total consolidated operating revenues. In 2005, Lodgepole Energy Marketing (Lodgepole) and BP Canada accounted for $123.2 million (18 percent) and $114.4 million (16 percent), respectively, of our consolidated operating revenues. Operating revenues from Lodgepole are recorded in our Natural Gas Gathering and Processing segment. Our Natural Gas Gathering and Processing segment and Natural Gas Pipelines segment have recorded operating revenues from BP Canada.

Operating Segment Information - The following tables set forth certain selected financial information for our operating segments for the periods indicated. Amounts in prior periods have been restated to conform to our current presentation.

Year Ended December 31, 2007	**Natural Gas Gathering and Processing**	**Natural Gas Pipelines (a)**	**Natural Gas Liquids Gathering and Fractionation**	**Natural Gas Liquids Pipelines (b)**	**Other and Eliminations**	**Total**
			(Thousands of dollars)			
Sales to unaffiliated customers	**$ 433,139**	**$ 194,170**	**$ 4,562,178**	**$ 15,280**	**$ 27**	**$5,204,794**
Sales to affiliated customers	**519,755**	**107,009**	**-**	**-**	**-**	**626,764**
Intersegment sales	**505,756**	**785**	**25,115**	**76,555**	**(608,211)**	**-**
Operating revenue	**$ 1,458,650**	**$ 301,964**	**$ 4,587,293**	**$ 91,835**	**$ (608,184)**	**$5,831,558**
Gain on sale of assets	**$ 1,825**	**$ 79**	**$ 39**	**$ 7**	**$ -**	**$ 1,950**
Operating income	**$ 187,815**	**$ 112,212**	**$ 111,976**	**$ 39,460**	**$ (4,680)**	**$ 446,783**
Equity earnings from investments	**$ 26,399**	**$ 62,487**	**$ -**	**$ 1,022**	**$ -**	**$ 89,908**
EBITDA	**$ 259,246**	**$ 207,196**	**$ 134,393**	**$ 53,411**	**$ 2,872**	**$ 657,118**
Investments in unconsolidated affiliates	**$ 298,701**	**$ 426,992**	**$ -**	**$ 30,567**	**$ -**	**$ 756,260**
Total assets	**$ 1,564,697**	**$ 1,164,111**	**$ 1,881,397**	**$ 1,214,833**	**$ 287,027**	**$6,112,065**
Capital expenditures	**$ 83,820**	**$ 138,919**	**$ 123,555**	**$ 363,460**	**$ 104**	**$ 709,858**

(a) - Our Natural Gas Pipelines segment has regulated and non-regulated operations. Our Natural Gas Pipelines segment's regulated operations had revenues of $252.5 million and operating income of $82.9 million for 2007.

(b) - All of our Natural Gas Liquids Pipelines segment's operations are regulated.

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Year Ended December 31, 2006	Natural Gas Gathering and Processing	Natural Gas Pipelines (a)	Natural Gas Liquids Gathering and Fractionation	Natural Gas Liquids Pipelines (b)	Other and Eliminations	Total
			(Thousands of dollars)			
Sales to unaffiliated customers	$ 478,848	$ 195,063	$ 3,467,048	$ -	$ 1,587	$4,142,546
Sales to affiliated customers	476,361	121,088	(1,747)	-	-	595,702
Intersegment sales	520,881	857	27,675	66,496	(615,909)	-
Operating revenue	$ 1,476,090	$ 317,008	$ 3,492,976	$ 66,496	$ (614,322)	$4,738,248
Gain on sale of assets	$ 373	$ 114,890	$ 47	$ 7	$ 166	$ 115,483
Operating income	$ 180,615	$ 237,330	$ 88,779	$ 29,086	$ (24,598)	$ 511,212
Equity earnings from investments	$ 22,616	$ 72,835	$ -	$ 432	$ -	$ 95,883
EBITDA	$ 249,136	$ 343,384	$ 109,753	$ 41,692	$ (15,396)	$ 728,569
Investments in unconsolidated affiliates	$ 294,308	$ 445,339	$ -	$ 9,232	$ -	$ 748,879
Total assets	$ 1,615,969	$ 1,224,576	$ 1,522,177	$ 511,949	$ 47,046	$4,921,717
Capital expenditures	$ 80,982	$ 48,598	$ 21,761	$ 49,322	$ 1,083	$ 201,746

(a) - Our Natural Gas Pipelines segment has regulated and non-regulated operations. Our Natural Gas Pipelines segment's regulated operations had revenues of $269.4 million and operating income of $211.0 million, including $113.9 million from a gain on sale of assets, for 2006.

(b) - All of our Natural Gas Liquids Pipelines segment's operations are regulated.

Year Ended December 31, 2005	Natural Gas Gathering and Processing	Natural Gas Pipelines (a)	Natural Gas Liquids Gathering and Fractionation	Natural Gas Liquids Pipelines	Other and Eliminations	Total
			(Thousands of dollars)			
Sales to unaffiliated customers	$ 275,287	$ 396,402	$ -	$ -	$ 24,572	$ 696,261
Sales to affiliated customers	-	7,683	-	-	-	7,683
Intersegment sales	-	-	-	-	-	-
Operating revenue	$ 275,287	$ 404,085	$ -	$ -	$ 24,572	$ 703,944
Operating income	$ 44,714	$ 214,168	$ -	$ -	$ (2,114)	$ 256,768
Equity earnings from investments	$ 22,473	$ 2,263	$ -	$ -	$ -	$ 24,736
EBITDA	$ 83,840	$ 285,871	$ -	$ -	$ 2,260	$ 371,971
Investments in unconsolidated affiliates	$ 254,286	$ 36,470	$ -	$ -	$ -	$ 290,756
Total assets	$ 594,379	$ 1,888,980	$ -	$ -	$ 44,407	$2,527,766
Capital expenditures	$ 16,602	$ 39,641	$ -	$ -	$ 3,639	$ 59,882

(a) - For 2005, all of our Natural Gas Pipelines segment's operations are regulated.

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We evaluate our performance based on EBITDA, which we define as earnings before interest, income taxes, depreciation and amortization less the cost of the equity component of AFUDC. Management uses EBITDA to compare the financial performance of its segments and to internally manage those business segments. Management believes that EBITDA provides useful information to investors as a measure of comparison with peer companies. EBITDA should not be considered an alternative to, or more meaningful than, net income or cash flow as determined in accordance with GAAP. EBITDA calculations may vary from company to company, so our computation of EBITDA may not be comparable with a similarly titled measure of another company.

The following tables set forth the reconciliation of net income to EBITDA by operating segment for the periods indicated.

Year Ended December 31, 2007	**Natural Gas Gathering and Processing**	**Natural Gas Pipelines**	**Natural Gas Liquids Gathering and Fractionation**	**Natural Gas Liquids Pipelines**	**Other and Eliminations**	**Total**
			(Thousands of dollars)			
Net income	**$ 222,838**	**$ 160,542**	**$ 117,362**	**$ 46,012**	**$ (139,007)**	**$407,747**
Minority interests	**-**	**387**	**-**	**29**	**-**	**416**
Interest expense, net	**(8,720)**	**11,785**	**(6,103)**	**3,176**	**138,809**	**138,947**
Depreciation and amortization	**45,099**	**32,380**	**23,134**	**13,062**	**29**	**113,704**
Income taxes	**29**	**5,772**	**-**	**-**	**3,041**	**8,842**
Allowance for equity funds used during construction	**-**	**(3,670)**	**-**	**(8,868)**	**-**	**(12,538)**
EBITDA	**$ 259,246**	**$ 207,196**	**$ 134,393**	**$ 53,411**	**$ 2,872**	**$657,118**

Year Ended December 31, 2006	Natural Gas Gathering and Processing	Natural Gas Pipelines	Natural Gas Liquids Gathering and Fractionation	Natural Gas Liquids Pipelines	Other and Eliminations	Total
			(Thousands of dollars)			
Net income	$ 190,701	$ 269,995	$ 77,050	$ 24,675	$ (117,235)	$ 445,186
Minority interests	-	2,392	-	-	-	2,392
Interest expense, net	4,590	26,252	8,776	5,422	88,442	133,482
Depreciation and amortization	43,032	32,841	20,738	12,035	13,399	122,045
Income taxes	10,813	12,822	3,189	847	(2)	27,669
Allowance for equity funds used during construction	-	(918)	-	(1,287)	-	(2,205)
EBITDA	$ 249,136	$ 343,384	$ 109,753	$ 41,692	$ (15,396)	$ 728,569

Year Ended December 31, 2005	Natural Gas Gathering and Processing	Natural Gas Pipelines	Natural Gas Liquids Gathering and Fractionation	Natural Gas Liquids Pipelines	Other and Eliminations	Total
			(Thousands of dollars)			
Net income	$ 67,552	$ 123,604	$ -	$ -	$ (44,143)	$ 147,013
Minority interests	-	45,674	-	-	-	45,674
Interest expense, net	219	44,990	-	-	41,694	86,903
Depreciation and amortization	16,045	67,608	-	-	2,708	86,361
Income taxes	24	4,522	-	-	2,001	6,547
Allowance for equity funds used during construction	-	(527)	-	-	-	(527)
EBITDA	$ 83,840	$ 285,871	$ -	$ -	$ 2,260	$ 371,971

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K. UNCONSOLIDATED AFFILIATES

Investments in Unconsolidated Affiliates - The following table sets forth our investments in unconsolidated affiliates for the periods indicated.

	Net Ownership Interest	December 31, 2007	December 31, 2006
		(Thousands of dollars)	
Northern Border Pipeline	50%	**$ 418,982**	$ 437,518
Bighorn Gas Gathering	49%	**97,716**	98,299
Fort Union Gas Gathering	37%	**85,197**	82,220
Lost Creek Gathering Company (a)	35%	**75,612**	74,151
Other	Various	**78,753**	56,691
Investments in unconsolidated affiliates		**$ 756,260 (b)**	$ 748,879 (b)

(a) - We are entitled to receive an incentive allocation of earnings from third-party gathering services revenue recognized by Lost Creek Gathering Company. As a result of the incentive, our share of Lost Creek Gathering Company's income exceeds its 35 percent ownership interest.

(b) - Equity method goodwill (Note D) was $185.6 million at December 31, 2007 and 2006.

Equity Earnings from Investments - The following table sets forth our equity earnings from investments for the periods indicated.

	Years Ended December 31, 2007	2006	2005
	(Thousands of dollars)		
Northern Border Pipeline (a)	**$ 62,008**	$ 72,393	$ -
Bighorn Gas Gathering	**7,416**	8,223	9,411
Fort Union Gas Gathering	**9,681**	9,030	6,747
Lost Creek Gathering Company	**4,790**	5,363	6,315
Guardian Pipeline (b)	**-**	-	2,263
Other	**6,013**	874	-
Equity earnings from investments	**$ 89,908**	$ 95,883	$ 24,736

(a) - Beginning January 1, 2006, our interest in Northern Border Pipeline is accounted for as an investment under the equity method (Note B). For the first three months of 2006, we included 70 percent of Northern Border Pipeline’s income in equity earnings from investments. After the sale of a 20 percent interest in Northern Border Pipeline in April 2006, we included 50 percent of Northern Border Pipeline's income in equity earnings from investments.

(b) - In April 2006, we acquired the 66-2/3 percent interest in Guardian Pipeline not previously owned by us, increasing our ownership to 100 percent. Following the completion of the transactions, we consolidated Guardian Pipeline retroactive to January 1, 2006 (Note B).

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Unconsolidated Affiliates Financial Information - Summarized combined financial information of our unconsolidated affiliates is presented below.

	December 31,	
	2007	**2006**
	(Thousands of dollars)	
Balance Sheet		
Current assets	**$ 102,805**	$ 76,376
Property, plant and equipment, net	**1,724,330**	1,678,099
Other noncurrent assets	**25,882**	24,109
Current liabilities	**79,593**	240,358
Long-term debt	**717,301**	492,017
Other noncurrent liabilities	**10,278**	2,494
Accumulated other comprehensive income (loss)	**(2,441)**	978
Owners' equity	**1,048,286**	1,042,737

	Years Ended December 31,		
	2007	**2006**	**2005**
	(Thousands of dollars)		
Income Statement			
Operating revenue	**$404,399**	$386,448	$101,390
Operating expenses	**172,997**	159,452	34,470
Net income	**184,434**	183,732	49,742
Distributions paid to us	**$103,785**	$123,427	$ 16,440

L. NET INCOME PER UNIT

Net income per unit is computed by dividing net income, after deducting the general partner's allocation, by the weighted average number of outstanding limited partner units. The general partner owns a 2 percent interest in us and also owns incentive distribution rights that provide for an increasing proportion of cash distributions from the partnership as the distributions made to limited partners increase above specified levels. For purposes of our calculation of net income per unit, net income is generally allocated to the general partner as follows: (1) an amount based upon the 2 percent general partner interest in net income, and (2) the amount of the general partner's incentive distribution rights based on the total cash distributions declared for the period. The amount of incentive distributions allocated to our general partners totaled $50.6 million, $31.6 million and $8.0 million for 2007, 2006 and 2005, respectively. The distribution paid to our general partner shown on the accompanying Consolidated Statements of Changes in Partners' Equity and Comprehensive Income of $54.7 million in 2007, $28.4 million in 2006 and $11.2 million in 2005, included incentive distributions paid to the general partners in 2007, 2006 and 2005 of approximately $47.1 million, $23.1 million and $8.0 million, respectively. Gains resulting from interim capital transactions, as defined in our Partnership Agreement, are generally not subject to distribution; however, our Partnership Agreement provides that if such distributions were made, the incentive distribution rights would not apply. Accordingly, the gain on sale of assets for 2007 and 2006 had no impact on the incentive distribution rights.

As discussed in Note B, we completed the ONEOK Transactions during the second quarter of 2006; however, for accounting purposes, the transactions were accounted for retroactive to January 1, 2006. Net income from the ONEOK Energy Assets prior to the April 2006 acquisition was approximately $35.8 million and has been reflected in our earnings for 2006. For purposes of our calculation of 2006 income per unit, these pre-acquisition earnings were allocated to the general partner, as they retained the related cash flow for that period.

The following summarizes our quarterly cash distribution activity for 2007:

- In January 2007, we declared a cash distribution of $0.98 per unit for the fourth quarter of 2006. The distribution was paid on February 14, 2007, to unitholders of record on January 31, 2007.
- In April 2007, we declared a cash distribution of $0.99 per unit for the first quarter of 2007. The distribution was paid on May 14, 2007, to unitholders of record as of April 30, 2007.
- In July 2007, we declared a cash distribution of $1.00 per unit for the second quarter of 2007. The distribution was paid on August 14, 2007, to unitholders of record on July 31, 2007.
- In October 2007, we declared a cash distribution of $1.01 per unit for the third quarter of 2007. The distribution was paid on November 14, 2007, to unitholders of record on October 31, 2007.

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On January 15, 2008, we declared a cash distribution of $1.025 per unit ($4.10 per unit on an annualized basis) for the fourth quarter of 2007. The distribution was paid on February 14, 2008, to unitholders of record on January 31, 2008.

M. RELATED-PARTY TRANSACTIONS

Intersegment and affiliate sales are recorded on the same basis as sales to unaffiliated customers. Our Natural Gas Gathering and Processing segment sells natural gas to ONEOK and its subsidiaries. A portion of our Natural Gas Pipelines segment's revenues are from ONEOK and its subsidiaries, which utilize both transportation and storage services.

As part of the ONEOK Transactions, we acquired certain contractual rights to the Bushton Plant that is leased by OBPI. Our Processing and Services Agreement with ONEOK and OBPI sets out the terms by which OBPI provides services at the Bushton Plant through 2012. We have contracted for all of the capacity of the Bushton Plant from OBPI. In exchange, we pay OBPI for all direct costs and expenses of the Bushton Plant, including reimbursement of a portion of OBPI's obligations under equipment leases covering the Bushton Plant.

In April 2006, we entered into a Services Agreement with ONEOK, ONEOK Partners GP and NBP Services (the Services Agreement) that replaced the Administrative Services Agreement between us and NBP Services. Under the Services Agreement, our operations and the operations of ONEOK and its affiliates can combine or share certain common services in order to operate more efficiently and cost effectively. Under the Services Agreement, ONEOK will provide to us at least the type and amount of services that it provides to its affiliates, including those services required to be provided pursuant to our Partnership Agreement. ONEOK Partners GP continues to operate our interstate natural gas pipeline assets according to each pipeline's operating agreement, except for the operating agreement between ONEOK Partners GP and Northern Border Pipeline, which terminated effective April 1, 2007. ONEOK Partners GP may purchase services from ONEOK and its affiliates pursuant to the terms of the Services Agreement. ONEOK Partners GP has no employees and utilizes the services of ONEOK and ONEOK Services Company to fulfill its responsibilities.

ONEOK and its affiliates provide a variety of services to us under the Services Agreement, including cash management and financing services, employee benefits provided through ONEOK's benefit plans, administrative services, insurance and office space leased in ONEOK's headquarters building and other field locations. Where costs are specifically incurred on behalf of one of our affiliates, the costs are billed directly to us by ONEOK. In other situations, the costs may be allocated to us through a variety of methods, depending upon the nature of the expense and activities. For example, a service that applies equally to all employees is allocated based upon the number of employees. However, an expense benefiting the consolidated company but having no direct basis for allocation is allocated by the modified Distrigas method, a method using a combination of ratios that include gross plant and investment, operating income and wages. All costs directly charged or allocated to us are included in our Consolidated Statements of Income.

An affiliate of ONEOK enters into some of the commodity derivative contracts at the direction of and on behalf of our Natural Gas Gathering and Processing segment. See Note C for a discussion of our derivative instruments and hedging activities.

The following table sets forth the transactions with related parties for the periods indicated.

	Years Ended December 31,		
	2007	**2006**	**2005**
	(Thousands of dollars)		
Revenues	**$626,764**	$595,702	$ 7,683
Expenses			
Administrative and general expenses	**$171,741**	$175,270	$52,579
Interest expense	-	21,372	-
Total expenses	**$171,741**	$196,642	$52,579

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N. QUARTERLY FINANCIAL DATA (UNAUDITED)

Year Ended December 31, 2007	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**
	(Thousands of dollars, except per unit amounts)			
Total revenues	**$1,168,674**	**$1,375,314**	**$1,410,257**	**$1,877,313**
Net margin	**$ 205,370**	**$ 217,570**	**$ 213,884**	**$ 259,069**
Operating income	**$ 104,376**	**$ 107,558**	**$ 105,116**	**$ 129,733**
Net income	**$ 95,756**	**$ 94,619**	**$ 95,916**	**$ 121,456**
Net income per unit	**$ 1.00**	**$ 0.97**	**$ 0.98**	**$ 1.27**

Year Ended December 31, 2006	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(Thousands of dollars, except per unit amounts)			
Total revenues	$ 1,179,613	$ 1,163,859	$ 1,218,541	$ 1,176,235
Net margin	$ 202,062	$ 213,111	$ 211,466	$ 216,909
Operating income	$ 100,174	$ 212,779	$ 107,673	$ 90,586
Net income	$ 70,504	$ 196,199	$ 98,222	$ 80,261
Net income per unit	$ 0.67	$ 2.22	$ 1.04	$ 0.82

Total revenues and net margin for the first and second quarters in the tables above were restated to be consistent with the classification used in our September 30, 2007 Quarterly Report on Form 10-Q and in this Annual Report on Form 10-K. The change was not material.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

We have established disclosure controls and procedures to ensure that information required to be disclosed by us, including our consolidated entities, in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms. Under the supervision and with the participation of senior management, including the Chief Executive Officer ("Principal Executive Officer") and the Chief Financial Officer ("Principal Financial Officer") of ONEOK Partners GP, our general partner, we evaluated our disclosure controls and procedures, as such term is defined under Rule 13a-15(e) promulgated under the Exchange Act. Based on this evaluation, the Principal Executive Officer and the Principal Financial Officer concluded that our disclosure controls and procedures were effective as of December 31, 2007, to ensure the timely disclosure of required information in our periodic SEC filings.

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of our management, including our Principal Executive Officer and Principal Financial Officer, we evaluated the effectiveness of our internal control over financial reporting based on the framework in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. Based on our evaluation under that framework and applicable SEC rules, our management concluded that our internal control over financial reporting was effective as of December 31, 2007.

Our internal control over financial reporting as of December 31, 2007, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report that is included herein (Item 8).

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Changes in Internal Controls Over Financial Reporting

We have made no changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) and 15d-15(f) under the Exchange Act) during the year ended December 31, 2007, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

Not applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Partnership Board of Directors and Audit Committee

We are managed under the direction of the Board of Directors of our sole general partner, ONEOK Partners GP, which consists of six members designated by ONEOK, the parent corporation of our general partner. We refer to the Board of Directors of ONEOK Partners GP as our Board of Directors. Because we are a limited partnership and meet the definition of a "controlled company" under the listing standards of the NYSE, certain listing standards of the NYSE are not applicable to us. Accordingly, Section 303A.01 of the NYSE Listed Company Manual, which would require that the Board of Directors of our general partner be comprised of a majority of independent directors, and Sections 303A.04 and 303A.05 of the NYSE Listed Company Manual, which would require that the Board of Directors of our general partner maintain a nominating committee and a compensation committee, each consisting entirely of independent directors, are not applicable to us. However, our Board of Directors has affirmatively determined that three members of our Board of Directors, Gary N. Petersen, Gerald B. Smith and Gil J. Van Lunsen, have no material relationship with us and are "independent" under our Governance Guidelines and the listing standards of the NYSE.

Our Board of Directors has appointed an Audit Committee consisting of the three members of our Board of Directors who are independent under our Governance Guidelines and the listing standards of the NYSE. The Audit Committee has oversight responsibility with respect to the integrity of our financial statements, the performance of our internal audit function, the independent auditor’s qualification and independence and our compliance with legal and regulatory requirements. The Audit Committee directly appoints, retains, evaluates and may terminate our independent auditor. The Audit Committee reviews our annual and quarterly financial statements. The Audit Committee also has the authority to review specific matters that may present a conflict of interest in order to determine if the resolution of such conflict proposed by our Board of Directors is fair and reasonable to our unitholders and to engage advisors to assist it in carrying out its duties. The Audit Committee has all other responsibilities required by the applicable NYSE listing standards and applicable SEC rules. The Board of Directors of our general partner has adopted a written charter for our Audit Committee.

The members of our Board of Directors and Audit Committee are not elected by unitholders. Accordingly, we do not have a procedure by which security holders may recommend nominees to our Board of Directors or Audit Committee. The persons designated as our executive officers serve in that capacity at the discretion of our Board of Directors.

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Directors and Executive Officers

The following table sets forth the members of the Board of Directors and Audit Committee and the executive officers of our general partner. There are no family relationships between any of our executive officers or members of the Board of Directors and the Audit Committee. Some of these individuals are also officers of certain of our subsidiaries or affiliates.

Name	Age	Position
John W. Gibson	55	Chairman of the Board, President and Chief Executive Officer
James C. Kneale	56	President and Chief Operating Officer, ONEOK, Inc. Member, Board of Directors
Curtis L. Dinan	40	Senior Vice President, Chief Financial Officer and Treasurer Member, Board of Directors
John R. Barker	60	Executive Vice President, General Counsel and Secretary
Caron A. Lawhorn	46	Senior Vice President and Chief Accounting Officer
Gary N. Petersen	57	Member, Board of Directors and Audit Committee
Gerald B. Smith	57	Member, Board of Directors and Chairman, Audit Committee
Gil J. Van Lunsen	65	Member, Board of Directors and Audit Committee

John W. Gibson became our president and chief executive officer effective January 1, 2007, and chairman of our Board of Directors on October 16, 2007. He served as our president and chief operating officer from May through December 2006. From 2005 until May 2006, he was president of ONEOK Energy companies, which included ONEOK's gathering and processing, natural gas liquids, pipelines and storage and energy services business segments, some of which were acquired by us in April 2006. Prior to that, he was president, Energy, from 2000 to 2005 for ONEOK.

James C. Kneale became the president and chief operating officer of ONEOK effective January 1, 2007. He served as our executive vice president and chief financial officer from May through December 2006. From 1999 to 2000, he was vice president, treasurer and chief financial officer and from 2001 to 2004, senior vice president, treasurer and chief financial officer for ONEOK. From 2005 through May 2006, he was executive vice president, finance and administration and chief financial officer for ONEOK.

Curtis L. Dinan became our senior vice president, chief financial officer and treasurer effective January 1, 2007. He was elected to our Board of Directors on October 16, 2007. Mr. Dinan is a member of both the Management and Audit Committees of Northern Border Pipeline. Mr. Dinan is also the Senior Vice President, Chief Financial Officer and Treasurer of ONEOK. Mr. Dinan served as senior vice president and chief accounting officer of ONEOK from August 2004 through December 2006 and served as vice president and chief accounting officer of ONEOK from February 2004 to August 2004. Prior to joining ONEOK in February 2004, Mr. Dinan served as an assurance and business advisory partner at Grant Thornton, LLP from 2002 to 2004.

John R. Barker became our executive vice president, general counsel and secretary in May 2006. Mr. Barker is also senior vice president, general counsel and assistant secretary for ONEOK, having been appointed to that position in 2004. From 1994 to 2004, he was a stockholder, president and director of Gable & Gotwals, a law firm located in Tulsa, Oklahoma, which provides legal services to both us and ONEOK.

Caron A. Lawhorn was named senior vice president and chief accounting officer on January 15, 2008. Ms. Lawhorn is Chair of the Audit Committee of Northern Border Pipeline. Ms. Lawhorn has served as senior vice president and chief accounting officer for ONEOK since January 1, 2007, and will continue to serve in this capacity. Prior to her current position, Ms. Lawhorn served ONEOK as senior vice president of financial services and treasurer from January 2005 to January 2007, vice president and controller from August 2004 to January 2005, vice president of audit and risk control from May 2003 to August 2004, and manager of audit services from September 1998 to May 2003.

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Gary N. Petersen was appointed to the Audit Committee in 2002. Since 1998, he has provided consulting services related to strategic and financial planning. Additionally, he is president of Endres Processing LLC. From 1977 to 1998, Mr. Petersen was employed by Reliant Energy-Minnegasco. He served as president and chief operating officer of Reliant Energy-Minnegasco from 1991 to 1998. Prior to his employment at Minnegasco, he was a senior auditor with Arthur Andersen. He currently serves on the boards of the YMCA of Metropolitan Minneapolis and the Dunwoody College of Technology.

Gerald B. Smith was appointed to the Audit Committee in 1994. He is chairman and chief executive officer and co-founder of Smith, Graham & Company Investment Advisors, a global investment management firm, which was founded in 1990. He is a member of the board of trustees of the Charles Schwab Family of Funds and lead independent director and member of the Cooper Industries audit committee. He is a former director of the Fund Management Board of Robeco Group, Rorento N.V. (Netherlands).

Gil J. Van Lunsen was appointed to the Audit Committee in March 2005. Prior to his retirement in 2000, Mr. Van Lunsen was a managing partner of KPMG LLP at the firm's Tulsa, Oklahoma office. He began his career with KPMG LLP in 1968. He is currently a director and audit committee chairman of Array Biopharma in Boulder, Colorado.

Director Compensation

Compensation for our non-management directors for the year ended December 31, 2007, consisted of an annual cash retainer of $65,000 and meeting fees of $1,000 for each Audit Committee meeting attended in person or $500 for each Audit Committee meeting attended by telephone. In addition, the chair of our Audit Committee received an additional annual cash fee of $10,000 and each other member of the Audit Committee received an additional cash fee of $5,000. Non-management directors are reimbursed for their expenses related to their attendance at Board of Director and Audit Committee meetings. A director who is also an officer or employee of ONEOK Partners GP or ONEOK receives no compensation for his or her service as a director.

We are required to indemnify the members of the Board of Directors and the general partner, its affiliates and its respective officers, directors, employees, agents and trustees to the fullest extent permitted by law against liabilities, costs and expenses incurred by any such person who acted in good faith and in a manner reasonably believed to be in, or (in the case of a person other than the general partner) not opposed to, our best interests and, with respect to any criminal proceedings, had no reasonable cause to believe the conduct was unlawful.

The following table sets forth the compensation paid to our non-management directors in 2007.

2007 DIRECTOR COMPENSATION

Name	Fees Earned or Paid in Cash ($)	Stock Awards ($)	Option Awards ($)	Non Equity Incentive Plan Compensation ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)	All Other Compensation ($)	Total ($)
Gary N. Petersen	77,000	—	—	—	—	—	77,000
Gerald B. Smith	82,000	—	—	—	—	—	82,000
Gil J. Van Lunsen	77,000	—	—	—	—	—	77,000

Compensation Committee Interlocks and Insider Participation

We do not have a compensation committee. During 2007, the compensation of our named executive officers was determined by ONEOK's Executive Compensation Committee, which consists of independent members of the ONEOK Board of Directors. No member of ONEOK's Executive Compensation Committee is, or was formerly, an officer, director or employee of ONEOK Partners or any if its subsidiaries.

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Governance Matters

Audit Committee Independence - Our Board of Directors has appointed a standing Audit Committee. Our guidelines for determining the independence of members of the Audit Committee are included in our Governance Guidelines and provide that members of the Audit Committee shall at all times qualify as independent under the listing standards of the NYSE and the applicable rules of the SEC and other applicable laws. At least annually, the Board of Directors reviews the relationships of each Audit Committee member with us to affirmatively determine the independence of each member. In February 2008, our Board of Directors affirmatively determined that Mr. Petersen, Mr. Smith, and Mr. Van Lunsen meet the standards for independence set forth in the Governance Guidelines and are therefore independent.

Audit Committee Financial Experts - Our Board of Directors annually reviews the financial expertise of the members of our Audit Committee. In February 2008, our Board of Directors determined that Mr. Petersen, Mr. Smith, and Mr. Van Lunsen are each "audit committee financial experts," as defined by the rules of the SEC.

Executive Sessions of Board and Audit Committee - Our Board of Directors has documented its governance practices in our Governance Guidelines. The Board of Directors of our general partner holds regular executive sessions in which non-management board members meet without any members of management present. The chairman of our Audit Committee, Mr. Smith, presides at regular sessions of the non-management members of our Board of Directors. Meetings of the non-management board and committee members are scheduled in connection with each in person meeting of our Board of Directors and Audit Committee.

Service on Other Audit Committees - Mr. Smith serves on the audit committee of one other public company. Mr. Van Lunsen serves on the audit committee of one other public company. The Board of Directors has determined that Mr. Smith and Mr. Van Lunsen’s service on these other audit committees does not impair their ability to effectively serve on our Audit Committee.

Section 16(a) Beneficial Ownership Reporting Compliance - Section 16(a) of the Exchange Act requires executive officers, members of the Board of Directors and persons who own more than 10 percent of our common units to file reports of ownership and changes in ownership with the SEC and the NYSE and to furnish us with copies of all Section 16(a) forms they file. Based solely on our review of the copies of such forms received by us during and with respect to the 2007 fiscal year, or written representations from certain reporting persons that no Form 5s were required for those persons, we believe that during 2007 our reporting persons complied with all applicable filing requirements in a timely manner.

Governance Guidelines - The Board of Directors of our general partner has adopted Governance Guidelines that address several governance matters, including responsibilities of directors, the composition and responsibility of the Audit Committee, the conduct and frequency of board meetings, management succession, director access to management and outside advisors, director orientation and continuing education, and annual self-evaluation of the board. The Board of Directors of our general partner recognizes that effective governance is an on-going process, and thus, the Board of Directors will review our Governance Guidelines periodically as deemed necessary.

Code of Ethics - The Board of Directors of our general partner has adopted an Accounting and Financial Reporting Code of Ethics applicable to our chief executive officer, chief financial officer and chief accounting officer. In addition to other matters, this code of ethics establishes policies to prevent wrongdoing and to promote honest and ethical conduct, including ethical handling of actual and apparent conflicts of interest, compliance with applicable laws, rules and regulations, full, fair, accurate, timely and understandable disclosure in public communications and prompt internal reporting violations of the code. We intend to promptly post on our website any amendment to, or waiver from, any provision of our Accounting and Financial Reporting Code of Ethics in accordance with the applicable rules of the SEC and NYSE.

Code of Conduct - The Board of Directors of our general partner has adopted a Code of Business Conduct applicable to the members of our Board of Directors and Audit Committee, our officers and the employees of ONEOK, ONEOK Partners GP, and ONEOK Services Company, who provide services to us. This code sets out our requirements for compliance with legal and ethical standards in the conduct of our business, including general business principles, legal and ethical obligations, compliance policies for specific subjects, obtaining guidance, the reporting of compliance issues and discipline for violations of the code. We intend to promptly post on our website any amendments to, or waivers from (including any implicit waiver), any provision of our Code of Business Conduct in accordance with the applicable rules of the SEC and NYSE.

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Web Access - We provide access through our website at *www.oneokpartners.com* to current information relating to our governance, including our Audit Committee Charter, our Accounting and Financial Reporting Code of Ethics, our Code of Business Conduct, our Governance Guidelines and other matters impacting our governance principles. You may copy each of these documents from our website. You may also contact the office of the secretary of ONEOK Partners GP for printed copies of these documents free of charge.

Communications with Directors - Our Board of Directors believes that it is management's role to speak for us. Our Board of Directors also believes that any communications between members of the Board of Directors and interested parties, including unitholders, should be conducted with the knowledge of our chairman, president and chief executive officer. Interested parties, including unitholders, may contact one or more members of our Board of Directors, including non-management directors and non-management directors as a group, by writing to the director or directors in care of our corporate secretary at our principal executive offices. A communication received from an interested party or unitholder will be promptly forwarded to the director or directors to whom the communication is addressed. A copy of the communication will also be provided to our president and chief executive officer. We will not, however, forward sales or marketing materials or correspondence primarily commercial in nature or not clearly identified as interested party or unitholder correspondence.

ITEM 11. EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

We do not directly employ any of the persons responsible for managing or operating our business. Instead, we are managed by our general partner, ONEOK Partners GP, the executive officers of which are employees of ONEOK. Certain officers of ONEOK Partners GP are deemed to be executive officers of us. We reimburse ONEOK for a portion of the total compensation paid to the executive officers of our general partner as provided by our Services Agreement with ONEOK. Please read "Certain Relationships and Related Party Transactions, and Director Independence - Services Agreement" for a description of the Services Agreement.

We do not have a compensation committee. The compensation of the officers of our general partner, who are deemed to be our officers, is set by the Executive Compensation Committee of the Board of Directors of ONEOK. A discussion of the objectives of, and other matters related to, ONEOK's compensation programs is included in ONEOK's compensation discussion and analysis and other disclosure related to ONEOK executive compensation contained in ONEOK's 2008 Proxy Statement as filed with the SEC (ONEOK 2008 Proxy Statement), a copy of which is provided on, and may be copied from, ONEOK's website at *www.oneok.com* and is available free of charge from the secretary of ONEOK Partners GP upon request.

Under our Services Agreement with ONEOK, a portion of the compensation expense for our named executive officers is allocated by ONEOK to us. The compensation amounts shown in the following table represent that portion of the named executive officer's total compensation which is allocated to and paid by us under the Services Agreement.

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The following table summarizes the compensation allocated to and paid by us in 2007 for our principal executive officer, principal financial officer and the three other most highly compensated executive officers of our general partner, ONEOK Partners GP, which we collectively refer to as the "named executive officers."

Summary Compensation Table For 2007

Name and Principal Position	Year	Salary ($)	Stock Awards ($)(1)	Option Awards ($)(2)	Non-Equity Incentive Plan Compensation ($)(3)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)(4)	All Other Compensation ($)(5)	Total ($)
David L. Kyle	2007	$405,705	$ 1,532,891	$ -	$ -	$ 1,096,862	$ 79,523	$3,114,981
Chairman and Chief Executive Officer (6)	2006	$307,043	$ 1,984,503	$ 4,987	$ 690,846	$ 444,716	$ 54,932	$3,487,027
John W. Gibson	2007	$295,926	$ 930,262	$ -	$ 536,963	$ 560,163	$ 67,930	$2,391,244
Chairman, President and Chief Executive Officer (6)	2006	$326,250	$ 794,237	$ 2,210	$ 491,250	$ 377,996	$ 43,448	$2,035,391
James C. Kneale	2007	$248,196	$ 849,464	$ 64,309	$ 389,000	$ 489,172	$ 33,201	$2,073,342
President and Chief Operating Officer, ONEOK, Inc.	2006	$158,014	$ 441,904	$ 173,629	$ 227,032	$ 185,975	$ 21,875	$1,208,429
Curtis L. Dinan	2007	$143,190	$ 122,707	$ -	$ 181,374	$ 45,738	$ 13,667	$ 506,676
Senior Vice President, Chief Financial Officer and Treasurer (6)	2006	$ 82,472	$ 102,515	$ -	$ 59,165	$ 21,727	$ 8,475	$ 274,354
Pierce H. Norton II	2007	$261,354	$ 199,306	$ -	$ 320,000	$ 37,175	$ 14,233	$ 832,068
Executive Vice President - Natural Gas	2006	$225,000	$ 165,200	$ -	$ 215,000	$ 32,769	$ 13,683	$ 651,652

(1) The amounts included in the table reflect the expense allocated to and recognized by us for restricted stock, restricted stock incentive units and performance units granted under the ONEOK Long-Term Incentive Plan (LTI Plan) and the ONEOK Equity Compensation Plan, the grant date fair value of which was determined in accordance with Financial Accounting Standards No. 123 (revised 2004), "Share-Based Payments," (Statement 123R). Assumptions used in the calculation of the value of these equity grants are included in Note O to the ONEOK audited financial statements for the year ended December 31, 2007, included in the ONEOK 2007 Annual Report on Form 10-K filed with the SEC on February 27, 2008.

Annual grants of restricted stock and restricted stock incentive units vest three years from the date of grant. Because no shares of ONEOK common stock are issued under a restricted stock incentive unit until the unit vests, no dividends are payable with respect to restricted stock incentive units. Performance units do not pay dividends and vest three years from the date of grant at which time the holder is entitled to receive a percentage (0 percent to 200 percent in increments of 50 percent) of the performance units granted based on ONEOK’s total shareholder return over the three-year performance cycle compared to the total shareholder return of a peer group of energy companies. Grants of restricted stock, restricted stock incentive units and performance units made in 2003 and grants of restricted stock incentive units and performance units made in 2006 and 2007 are payable in shares of ONEOK common stock upon vesting. Grants of restricted stock incentive units and performance units made in 2004 and 2005 are payable one-third in cash and two-thirds in shares upon vesting. The fair value of restricted stock and restricted stock incentive units for the purposes of Statement 123R was determined on the date of grant based on the closing stock price of ONEOK common stock on the grant date, adjusted for the current dividend yield. The grant date fair value of the performance units granted in 2003, 2004 and 2005 for the purposes of Statement 123R was determined on the date of grant based on the closing stock price of ONEOK common stock on the grant date, adjusted for the current dividend yield. With respect to the performance units granted in 2006 and 2007, the grant date fair value for the purposes of Statement 123R was determined using a valuation model that considers the market condition (total shareholder return), using assumptions developed from historical information of ONEOK and the referenced peer group.

(2) No options were granted by ONEOK in 2007. However, the remaining unamortized expense from restored options granted in 2006 was fully recognized as of May 2007. No options were granted in 2006, except for restored options granted in connection with the exercise of options granted under the LTI Plan. Effective January 1, 2007, the restorative feature of all outstanding ONEOK stock options was eliminated. The 2003 option grant vested on February 20, 2006. The amounts included in the table reflect our allocated portion of the grant date fair value of the 2003 grant and the restored options granted in 2006 as expensed in accordance with Statement 123R. Assumptions used in the calculation of the value of option grants are included in Note O to the ONEOK audited financial statements for the year ended December 31, 2007, included in the ONEOK 2007 Annual Report on Form 10-K filed with the SEC on February 27, 2008.

(3) Reflects the amounts allocated to and paid by us under the ONEOK annual officer incentive plan. The plan provides that ONEOK officers may receive annual cash incentive awards based on the performance and profitability of ONEOK, the performance of particular business units of ONEOK, and individual performance. The corporate and business unit criteria and individual performance criteria are established annually

by the ONEOK Executive Compensation Committee of the ONEOK Board of Directors. The Committee also establishes annual target awards for each ONEOK officer. For a discussion of the performance criteria established by the ONEOK Executive Compensation Committee for awards under the 2007 annual officer incentive plan, see "Components of Compensation - Annual Cash Compensation" in the ONEOK 2008 Proxy Statement.

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(4) Reflects the portion of the aggregate current year change in pension values and above market earnings on nonqualified deferred compensation allocated to us for each named executive officer. The change in pension values is based on the change of the present value of the benefit. For a discussion of the ONEOK pension plan, see the ONEOK 2008 Proxy Statement. The present value is based on the earliest age for which an unreduced benefit is available (age 62) and assumptions from the September 30, 2007 and 2006 measurement dates for the ONEOK pension plan.

Our allocated portion of above market earnings on nonqualified deferred compensation for 2006 and 2007 were $671 and $0, respectively, for Mr. Kyle and $394 and $765, respectively, for Mr. Kneale. No other named executive officers received above market earnings. For additional information on the ONEOK, Inc. Employee Nonqualified Deferred Compensation Plan, see "Long-Term Compensation Plans - Nonqualified Deferred Compensation Plan" in the ONEOK 2008 Proxy Statement.

(5) Reflects the portion allocated to us of the amounts paid as ONEOK's dollar for dollar match of contributions made by the named executive officer under the ONEOK, Inc. Employee Nonqualified Deferred Compensation Plan, amounts paid as ONEOK's dollar for dollar match of contributions made by the named executive officer under the Thrift Plan for Employees of ONEOK, Inc. and Subsidiaries; amounts paid for country club membership; amounts paid as tax reimbursements for employee stock awards under the ONEOK, Inc. Employee Stock Award Program; amounts expensed in accordance with Statement 123R for shares issued under the ONEOK, Inc. Employee Stock Award Program; and amounts paid as employee service awards, as follows:

Name	Year	Match Under Nonqualified Deferred Compensation Plan (a)	Match Under Thrift Plan (b)	Country Club Membership	Service Award	Employee Stock Award (c)	Tax Reimbursement
David L. Kyle	2007	$ 72,669	$ 6,444	$ -	$ -	$ 238	$ 172
	2006	$ 49,936	$ 4,768	$ -	$ -	$ 130	$ 98
John W. Gibson	2007	$ 30,070	$ 6,444	$ 31,006	$ -	$ 238	$ 172
	2006	$ 33,075	$ 9,900	$ -	$ -	$ 270	$ 203
James C. Kneale	2007	$ 26,347	$ 6,444	$ -	$ -	$ 238	$ 172
	2006	$ 16,455	$ 4,795	$ -	$ 396(d)	$ 131	$ 98
Curtis L. Dinan	2007	$ 6,873	$ 6,444	$ -	$ -	$ 238	$ 112
	2006	$ 3,550	$ 4,733	$ -	$ -	$ 129	$ 63
Pierce H. Norton II	2007	$ -	$ 13,500	$ -	$ -	$ 498	$ 235
	2006	$ -	$ 13,200	$ -	$ -	$ 361	$ 122

(a) For additional information on the ONEOK, Inc. Employee Nonqualified Deferred Compensation Plan, see "Long-Term Compensation Plans - Nonqualified Deferred Compensation Plan" in the ONEOK 2008 Proxy.

(b) The Thrift Plan for Employees of ONEOK, Inc. and Subsidiaries is a tax qualified plan which covers all ONEOK employees. Employee contributions are discretionary. Subject to certain limits, ONEOK matches 100 percent of employee contributions to the plan up to a maximum of 6 percent.

(c) Under the ONEOK, Inc. Employee Stock Award Program, ONEOK issued, for no consideration, to all eligible full-time and short-term disabled employees, one share of ONEOK common stock when the closing price of ONEOK common stock on the NYSE was for the first time at or above $26 per share. Nine and 10 shares were issued to each named executive officer under this program in 2006 and 2007, respectively.

(d) This amount was awarded Mr. Kneale for 25 years of service to ONEOK.

Other than as set forth above, the named executive officers did not receive perquisites or other personal benefits with an aggregate value of $10,000 or more.

(6) Effective January 1, 2007, Mr. Kyle became our chairman of the Board of Directors and Mr. Gibson became our president and chief executive officer. Effective October 16, 2007, Mr. Kyle retired as our chairman of the Board of Directors, Mr. Gibson became our chairman of the Board of Directors in addition to his position as president and chief executive officer, and Mr. Dinan became a member of our Board of Directors.

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Potential Post-Employment Payments and Payments upon a Change in Control

Payments Made Upon Any Termination - Regardless of the manner in which a named executive officer's employment terminates, he is entitled to receive amounts earned during his term of employment. Such amounts include:

- accrued but unpaid salary;
- amounts contributed under the Thrift Plan for Employees of ONEOK, Inc. and Subsidiaries and the ONEOK, Inc. Employee Nonqualified Deferred Compensation Plan; and
- amounts accrued and vested through the ONEOK retirement plan and supplemental executive retirement plan (SERP).

Payments Made Upon Retirement - In the event of the retirement of a named executive officer, in addition to the items identified above, such named executive officer will:

- be entitled to certain exercise rights with respect to each outstanding and vested stock option granted under the ONEOK LTI Plan;
- be entitled to receive a prorated portion of each outstanding performance unit granted under the ONEOK Equity Compensation Plan upon the completion of the performance cycle;
- be entitled to receive a prorated portion of each outstanding restricted stock incentive unit granted under the ONEOK LTI Plan and the ONEOK Equity Compensation Plan upon completion of the restricted cycle; and
- be entitled to receive ONEOK health and life benefits for the retiree and qualifying dependents, as applicable.

Payments Made Upon Death or Disability - In the event of the death or disability of a named executive officer, in addition to the benefits listed under the headings "Payments Made Upon Any Termination" and "Payments Made Upon Retirement" above, the named executive officer will receive benefits under ONEOK's disability plan or payments under ONEOK's life insurance plan, as appropriate.

Payments Made Upon a Change in Control - Effective January 2005, ONEOK entered into amended and restated termination agreements with each of our named executive officers. Each termination agreement has an initial two-year term from the date the agreement was entered into and is automatically extended in one-year increments after the expiration of the initial term unless ONEOK provides notice of non-renewal to the officer, or the officer provides notice of non-renewal to ONEOK, at least 90 days before the January 1 preceding any termination date of the agreement. If a "change in control" of ONEOK occurs, the term of each termination agreement will not expire for at least three years after the change in control. Relative to the overall value of the Partnership, the potential benefits payable upon a change in control under these agreements are comparatively minor.

Effective December 21, 2006, ONEOK's termination agreement with Mr. Kyle was terminated by mutual agreement as a result of the change in Mr. Kyle's position with ONEOK. As a result, Mr. Kyle is not eligible to receive payments in the event of termination following a change in control. Also, effective December 21, 2006, ONEOK entered into an amended and restated termination agreement with Mr. Gibson which provides for an initial term through January 1, 2008, and is thereafter automatically extended until either party gives written notice of its election to terminate the agreement 90 days following the date of the notice.

Under the termination agreements, all change in control benefits are "double trigger." Payments and benefits under these termination agreements are payable if the officer's employment is terminated by ONEOK without "just cause" or by the officer for "good reason" at any time during the three years following a change in control. In general, severance payments and benefits include a lump sum payment in an amount equal to the sum of (1) for Messrs. Gibson and Kneale three times, and for Messrs. Dinan and Norton two times, the aggregate of the officer's annual salary as then in effect, plus the greater of either the amount of the officer's bonus received in the prior year or the officer's target bonus for the then current period, and (2) a prorated portion of the officer's target short-term incentive compensation. Messrs. Gibson and Kneale would also be entitled to continuation of health and welfare benefits for 36 months and accelerated benefits under the ONEOK, Inc. 2005 Supplemental Executive Retirement Plan. Messrs. Dinan and Norton would be entitled to continuation of health and welfare benefits for 24 months. In the case of Messrs. Gibson and Kneale, ONEOK will make gross up payments to them to cover any excise taxes due if any portion of their severance payments constitutes an excess parachute payment. For Messrs. Dinan and Norton, severance payments will be reduced if the net after-tax benefit to such named executive officer exceeds the net after-tax benefit if such reduction were not made. ONEOK will make gross up payments to such officers only if the severance payments, as reduced, are subsequently deemed to constitute excess parachute payments.

For the purposes of these agreements, a "change in control" generally means any of the following events:

- an acquisition of ONEOK voting securities by any person that results in the person having beneficial ownership of 20 percent or more of the combined voting power of ONEOK's outstanding voting securities, other than an acquisition directly from ONEOK;

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- the current members of the ONEOK Board, and any new director approved by a vote of at least two-thirds of the ONEOK Board, cease for any reason to constitute at least a majority of the ONEOK Board, other than in connection with an actual or threatened proxy contest (collectively, the "Incumbent Board");
- a merger, consolidation or reorganization with ONEOK or in which ONEOK issues securities, unless (a) ONEOK's shareholders immediately before the transaction, as a result of the transaction, own, directly or indirectly, at least 50 percent of the combined voting power of the voting securities of ONEOK resulting from the transaction, (b) the members of the ONEOK Incumbent Board after the execution of the transaction agreement constitute at least a majority of the members of the Board of ONEOK resulting from the transaction, or (c) no person other than persons who, immediately before the transaction owned 30 percent or more of ONEOK's outstanding voting securities, has beneficial ownership of 30 percent or more of the outstanding voting securities of ONEOK resulting from the transaction; or
- ONEOK completes the liquidation or dissolution or the sale or other disposition of all or substantially all of ONEOK's assets.

For the purposes of these agreements, "just cause" means the executive's conviction in a court of law of a felony, or any crime or offense in a court of law of a felony, or any crime or offense involving misuse or misappropriation of money or property; the executive's violation of any covenant, agreement or obligation not to disclose confidential information regarding our business; any violation by the executive of any covenant not to compete with us; any act of dishonesty by the executive which adversely affects our business; any willful or intentional act of the executive which adversely affects our business, or reflects unfavorably on our reputation; the executive's use of alcohol or drugs which interferes with the executive's performance of duties as our employee; or the executive's failure or refusal to perform the specific directives of our Board of Directors or its officers, which directives are consistent with the scope and nature of the executive's duties and responsibilities. The existence and occurrence of all of such causes are to be determined by us, in our sole discretion, provided, that nothing contained in these provisions of these agreements are to be deemed to interfere in any way with our right to terminate the executive's employment at any time without cause.

For the purposes of these agreements, "good reason" means a demotion, loss of title or significant authority or responsibility of the executive with respect to the executive's employment with us from those in effect on the date of a change in control, a reduction of salary of the executive from that received from us immediately prior to the date of a change in control, a reduction in short-term and/or long-term incentive targets from those applicable to the executive immediately prior to the date of a change in control, the relocation of our principal executive offices to a location outside the metropolitan area of Tulsa, Oklahoma, or our requiring a relocation of principal place of employment of the executive, or the failure of a successor corporation to explicitly assume these termination agreements.

Potential Post-Employment Payment Tables - The following tables reflect estimates of the amount of incremental compensation due to each named executive officer in the event of such executive's termination of employment upon death, disability or retirement, termination of employment without cause or termination of employment without cause or with good reason within three years following a change in control. The amounts shown assume that such termination was effective as of December 31, 2007, and are estimates of the amounts which would be paid out to the executives upon such termination. The actual amounts to be paid out can only be determined at the time of such executive's separation from the Partnership.

In addition to the amounts set forth in the following tables, in the event of termination of employment for any of the reasons set forth in the tables, each of the named executive officers would receive the following payments or benefits, which had been earned as of December 31, 2007: David L. Kyle, $1,576,417 in exercisable options and $106,089 in pension and SERP benefits; John W. Gibson, $585,977 in exercisable options and $135,667 in pension and SERP benefits; James C. Kneale, $334,826 in exercisable options and $65,977 in pension and SERP benefits; Curtis L. Dinan, $1,990 in pension and SERP benefits; Pierce H. Norton II, $2,353 in pension and SERP benefits.

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David L. Kyle	Termination Upon Death, Disability, & Retirement		Termination Without Cause		Termination Following a Change in Control	
INCREMENTAL COMPENSATION						
(payment contingent on termination)						
Cash Severance	$	-	$	-	$	-
Equity						
Restricted Stock/Units	$	-	$	-	$	-
Performance Shares/Units	$	-	$	-	$	-
Unexercisable Options	$	-	$	-	$	-
Total	$	-	$	-	$	-
Retirement Benefits						
SERP	$	-	$	-	$	-
Total	$	-	$	-	$	-
Other Benefits						
Health & Welfare	$	-	$	-	$	-
Tax Gross-Ups	$	-	$	-	$	-
Total	$	-	$	-	$	-
Total	$	-	$	-	$	-

John W. Gibson	Termination Upon Death, Disability, & Retirement		Termination Without Cause		Termination Following a Change in Control	
INCREMENTAL COMPENSATION						
(payment contingent on termination)						
Cash Severance	$	-	$	-	$	1,825,673
Equity						
Restricted Stock/Units	$	1,023,550	$	1,023,550	$	3,814,317
Performance Shares/Units	$	757,190	$	-	$	1,303,492
Unexercisable Options	$	-	$	-	$	-
Total	$	1,780,740	$	1,023,550	$	5,117,809
Retirement Benefits						
SERP	$	-	$	-	$	114,448
Total	$	-	$	-	$	114,448
Other Benefits						
Health & Welfare	$	-	$	-	$	13,605
Tax Gross-Ups	$	-	$	-	$	2,688,697
Total	$	-	$	-	$	2,702,302
Total	$	1,780,740	$	1,023,550	$	9,760,232

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James C. Kneale	Termination Upon Death, Disability, & Retirement	Termination Without Cause	Termination Following a Change in Control
INCREMENTAL COMPENSATION			
(payment contingent on termination)			
Cash Severance	$ -	$ -	$ 1,639,526
Equity			
Restricted Stock/Units	$ 942,005	$ 942,005	$ 1,645,392
Performance Shares/Units	$ 794,428	$ -	$ 1,196,648
Unexercisable Options	$ -	$ -	$ -
Total	$ 1,736,433	$ 942,005	$ 2,842,040
Retirement Benefits			
SERP	$ -	$ -	$ 125,770
Total	$ -	$ -	$ 125,770
Other Benefits			
Health & Welfare	$ -	$ -	$ 10,487
Tax Gross-Ups	$ -	$ -	$ 1,388,140
Total	$ -	$ -	$ 1,398,627
Total	$ 1,736,433	$ 942,005	$ 6,005,963

Curtis L. Dinan	Termination Upon Death, Disability, & Retirement	Termination Without Cause	Termination Following a Change in Control
INCREMENTAL COMPENSATION			
(payment contingent on termination)			
Cash Severance	$ -	$ -	$ 443,889
Equity			
Restricted Stock/Units	$ 114,505	$ 114,505	$ 170,950
Performance Shares/Units	$ 207,359	$ -	$ 363,268
Unexercisable Options	$ -	$ -	$ -
Total	$ 321,864	$ 114,505	$ 534,218
Retirement Benefits			
SERP	$ -	$ -	$ -
Total	$ -	$ -	$ -
Other Benefits			
Health & Welfare	$ -	$ -	$ 10,117
Tax Gross-Ups	$ -	$ -	$ -
Total	$ -	$ -	$ 10,117
Total	$ 321,864	$ 114,505	$ 988,224

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Pierce H. Norton II	Termination Upon Death, Disability, & Retirement	Termination Without Cause	Termination Following a Change in Control
INCREMENTAL COMPENSATION			
(payment contingent on termination)			
Cash Severance	$ -	$ -	$ 952,708
Equity			
Restricted Stock/Units	$ 218,272	$ 218,272	$ 313,390
Performance Shares/Units	$ 370,289	$ -	$ 582,010
Unexercisable Options	$ -	$ -	$ -
Total	$ 588,561	$ 218,272	$ 895,400
Retirement Benefits			
SERP	$ -	$ -	$ -
Total	$ -	$ -	$ -
Other Benefits			
Health & Welfare	$ -	$ -	$ 21,197
Tax Gross-Ups	$ -	$ -	$ -
Total	$ -	$ -	$ 21,197
Total	$ 588,561	$ 218,272	$ 1,869,305

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ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Beneficial Ownership

The following table sets forth the beneficial ownership of our common units and the common stock of ONEOK, the parent company of our general partner, as of February 1, 2008, by each named executive officer, each member of our Board of Directors of our general partner, and all executive officers and members of our Board of Directors as a group. Other than as set forth below, no person is known to us to beneficially own more than five percent of our common units.

Name and Address of Beneficial Owner (1)	Common Units	Percent of Common Units	Class B Units	Percent of Class B Units	Percent of All Units	ONEOK Shares (2)	Percent of ONEOK Shares
David L. Kyle	35,000	*	-	-	*	540,628(3)	*
John W. Gibson	2,500	*	-	-	*	149,194(4)	*
James C. Kneale	-	-	-	-	-	195,426(5)	*
Curtis L. Dinan	-	-	-	-	-	13,660	*
John R. Barker	-	-	-	-	-	9,101	*
Pierce H. Norton II	6,778	*	-	-	*	3,086	*
Caron A. Lawhorn	-	-	-	-	-	19,513(6)	*
Gary N. Petersen	5,892	*	-	-	*	-	-
Gerald B. Smith	-	-	-	-	-	-	-
Gil J. Van Lunsen	-	-	-	-	-	-	-
All directors and executive officers as a group	50,170	*	-	-	-	930,608	*
ONEOK, Inc. and affiliates	500,000	1.078	36,494,126	100	44.63	-	-

* Less than 1 percent.
(1) The business address for each of the beneficial owners is c/o ONEOK Partners, L.P., 100 West Fifth Street, Tulsa, Oklahoma 74103-4298.
(2) Includes shares of ONEOK common stock held by members of the family of the director or executive officer for which the director or executive officer has sole or shared voting or investment power, shares of common stock held in ONEOK's Direct Stock Purchase and Dividend Reinvestment Plan, Thrift Plan for Employees of ONEOK, Inc. and Subsidiaries and shares that the board member or executive officer has the right to acquire within 60 days of February 1, 2008, upon exercise of stock options granted under the LTI Plan.
(3) Includes 196,763 shares exercisable within 60 days of February 1, 2008. Includes 20,000 shares held by Mr. David L. Kyle, 500 shares held by Mr. Kyle's son, and 500 shares held by Mr. Kyle's step-son. Mr. Kyle disclaims beneficial ownership of these shares.
(4) Includes 59,948 shares exercisable within 60 days of February 1, 2008, and 765 shares of phantom stock under the ONEOK, Inc. Nonqualified Deferred Compensation Plan.
(5) Includes 65,853 shares exercisable within 60 days of February 1, 2008.
(6) Includes 4,745 shares exercisable within 60 days of February 1, 2008.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Related-Person Transactions

Our Board of Directors recognizes that transactions between us and related persons (ONEOK and its subsidiaries, affiliates and their and our executive officers, directors, and their immediate family members) can present potential or actual conflicts of interest and create the appearance our decisions are based on considerations other than our best interests and our unitholders. Accordingly, as a general matter, it is our preference to avoid related person transactions. Nevertheless, we recognize that there are situations where related person transactions may be in, or may not be inconsistent with, our best interests and our unitholders including, but not limited to, situations where we acquire products or services from related persons on an arm's length basis on terms comparable to those provided to unrelated third parties.

In the event we enter into a transaction in which ONEOK or its subsidiaries or affiliates or their or our executive officers (other than an employment relationship), directors, or a members of their immediate family have a direct or indirect material interest, the transaction is presented to our Audit Committee and, if warranted, our Board of Directors for review, to determine if the transaction creates a conflict of interest and is otherwise fair to us. We require each executive officer and director of our general partner to annually provide us written disclosure of any transaction between the officer or director and us. Our Board of Directors reviews this disclosure in connection with its annual review of the independence of our Audit Committee. These procedures are not in writing but are evidenced through the meeting agendas of our Board of Directors and our Audit Committee.

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The ONEOK Transactions

For a description of the ONEOK Transactions, see Note B of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K at page 64.

Relationship with ONEOK

ONEOK owns our sole general partner, ONEOK Partners GP, and is able to elect members of our Board of Directors and our Audit Committee. Other relationships include the following.

Cash Distributions - ONEOK owns approximately 0.5 million of our common units and approximately 36.5 million of our Class B limited units, which, when combined with its general partner interest, represents an approximate 45.7 percent interest in us. For 2007, we declared total cash distributions to ONEOK of $207.4 million, which included $50.6 million related to its incentive distribution rights. Additional information about our cash distribution policy is included in Item 5, Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.

Services Agreement - In April 2006, we entered into a Services Agreement with ONEOK, ONEOK Partners GP and NBP Services. Under the Services Agreement, our operations and the operations of ONEOK and its affiliates can combine or share certain common services in order to operate more efficiently and cost effectively. Under the Services Agreement, ONEOK will provide to us at least the type and amount of services that it provides to its affiliates, including those services required to be provided pursuant to our Partnership Agreement.

ONEOK and its affiliates provide a variety of services to us under the Services Agreement, including cash management and financing services, employee benefits provided through ONEOK's benefit plans, administrative services, insurance and office space leased in ONEOK's headquarters building and other field locations. Where costs are specifically incurred on behalf of one of our affiliates, the costs are billed directly to us by ONEOK. In other situations, the costs may be allocated to us through a variety of methods, depending upon the nature of the expense and activities. For example, a service that applies equally to all employees is allocated based upon the number of employees. However, an expense benefiting the consolidated company but which has no direct basis for allocation is allocated by the modified Distrigas method, a method using a combination of ratios that include gross plant and investment, operating income and wages. All costs directly charged or allocated to us are included in our Consolidated Statements of Income.

In 2007, the aggregate amount charged by ONEOK, NBP Services and their affiliates to us for their services was approximately $171.7 million.

Operating and Administrative Services Agreements - ONEOK Partners GP provides certain administrative, operating and management services to us and Midwestern Gas Transmission, Viking Gas Transmission, and Guardian Pipeline through operating agreements. We, along with Midwestern Gas Transmission, Viking Gas Transmission, and Guardian Pipeline are charged for the salaries, benefits and expenses of ONEOK Partners GP incurred in connection with the operating agreements.

Transportation Agreements - ONEOK Energy Services, a subsidiary of ONEOK, became an affiliate of Northern Border Pipeline in November 2004 in connection with ONEOK's purchase of ONEOK Partners GP. We do not operate Northern Border Pipeline, but we are a 50 percent owner of the pipeline. In 2007, 3 percent of Northern Border Pipeline's design capacity was contracted on a firm basis with ONEOK Energy Services. Revenue from ONEOK Energy Services for 2007 was $5.1 million. As of January 31, 2008, 3 percent of Northern Border Pipeline's design capacity was contracted on a firm basis with ONEOK Energy Services for 2008.

Our Natural Gas Gathering and Processing segment sold $519.8 million of natural gas to ONEOK and its subsidiaries during 2007. Of our Natural Gas Pipelines segment's revenues, $107.0 million were from ONEOK and its subsidiaries during 2007 for both transportation and storage services.

Bushton Plant - As part of the ONEOK Transactions, we acquired contractual rights to the Bushton Plant that is leased by OBPI. Our Processing and Services Agreement with ONEOK and OBPI sets out the terms by which OBPI provides services at the Bushton Plant through 2012. We have contracted for all the capacity of the Bushton Plant from OBPI. In exchange for such services, we pay OBPI for all direct costs and expenses of operating the Bushton Plant, including reimbursement of a portion of OBPI's obligations under equipment leases covering the Bushton Plant.

Derivative Contracts - An affiliate of ONEOK from time to time enters into commodity derivative contracts on behalf of our Natural Gas Gathering and Processing segment. See Note C of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for a discussion of our derivative instruments and hedging activities.

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Relationship with TransCanada

As part of the ONEOK Transactions, in April 2006 ONEOK acquired ONEOK NB, formerly known as Northwest Border Pipeline Company, an affiliate of TransCanada that held a 0.35 percent general partner interest in us. In 2006, we declared total cash distributions to TransCanada of $0.7 million, which included $0.5 million related to its incentive distribution rights. Additional information about our cash distribution policy is included in Item 5, Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.

ONEOK Partners GP and TransCanada's affiliate became the operator of Northern Border Pipeline and entered into a transition services agreement for the transfer of the operator function effective April 1, 2007. Northern Border Pipeline agreed to pay ONEOK Partners GP an amount up to $1.0 million per year for years 2007 through 2011, to reimburse ONEOK Partners GP for shared equipment and furnishings acquired by ONEOK Partners GP and used to support Northern Border Pipeline operations.

Conflicts of Interest

Our Board of Directors, whose members are designated by our general partner, ONEOK Partners GP, establishes our business policies.

Our general partner, which is a subsidiary of ONEOK, and its respective affiliates currently engage or may engage in the businesses in which we engage or in which we may engage in the future. As a result, conflicts of interest may arise between our general partner and its affiliates, and us. If such conflicts arise, the members of our Board of Directors generally have a fiduciary duty to resolve such conflicts in a manner that is in our best interest.

TC PipeLines (a 50 percent owner and operator of Northern Border Pipeline) and its affiliates are also engaged in interstate natural gas pipeline transportation in the United States separate from their interest in Northern Border Pipeline. As a result, conflicts also may arise between TransCanada and its affiliates or TC PipeLines and its affiliates, and Northern Border Pipeline. If such conflicts arise, the representatives on the Northern Border Management Committee generally have a fiduciary duty to resolve such conflicts in a manner that is in the best interest of Northern Border Pipeline.

Unless otherwise provided for in a partnership agreement, the laws of Delaware and Texas generally require a general partner of a partnership to adhere to fiduciary duty standards under which it owes its partners the highest duties of good faith, fairness and loyalty. Similar rules apply to persons serving on our general partner's Board of Directors or the Northern Border Management Committee. Because of the competing interests identified above, our Partnership Agreement and the partnership agreement for Northern Border Pipeline contain provisions that modify certain of these fiduciary duties. For example:

- Our Partnership Agreement states that our general partner, its affiliates and their officers and directors will not be liable for damages to us, our limited partners or their assignees for errors of judgment or for any acts or omissions if the general partner and such other persons acted in good faith.
- Our Partnership Agreement allows our general partner and our Board of Directors to take into account the interests of other parties in addition to our interests in resolving conflicts of interest.
- Our Partnership Agreement provides that our general partner will not be in breach of its obligations under our Partnership Agreement or its duties to us or our unitholders if the resolution of a conflict is fair and reasonable to us. The latitude given in our Partnership Agreement in connection with resolving conflicts of interest may significantly limit the ability of a unitholder to challenge what might otherwise be a breach of fiduciary duty.
- Our Partnership Agreement provides that a purchaser of common units is deemed to have consented to certain conflicts of interest and actions of our general partner and its affiliates that might otherwise be prohibited and to have agreed that such conflicts of interest and actions do not constitute a breach by the general partner of any duty stated or implied by law or equity.
- The Audit Committee of our general partner will, at the request of the general partner or a member of our Board of Directors, review conflicts of interest that may arise between a general partner and its affiliates (or the member of our Board of Directors designated by it), and the unitholders or us. Any resolution of a conflict approved by the Audit Committee is conclusively deemed fair and reasonable to us.
- The partnership agreement of Northern Border Pipeline relieves us and TC PipeLines, our affiliates, and transferees from any duty to offer business opportunities to Northern Border Pipeline, subject to specified exceptions.

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We are required to indemnify the general partner, the members of its Board of Directors, and its affiliates and their respective officers, directors, employees, agents and trustees to the fullest extent permitted by law against liabilities, costs and expenses incurred by any such person who acted in good faith and in a manner reasonably believed to be in, or (in the case of a person other than our general partner) not opposed to, our best interests and with respect to any criminal proceedings, had no reasonable cause to believe the conduct was unlawful.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Selection of PricewaterhouseCoopers LLP

On April 26, 2007, the Audit Committee of our Board of Directors approved the dismissal of KPMG LLP and the engagement of PricewaterhouseCoopers LLP as our principal independent registered public accountant effective with the filing of our Quarterly Report on Form 10-Q for the period ended March 31, 2007, on May 2, 2007.

Audit and Non-Audit Fees

Audit services provided by PricewaterhouseCoopers LLP during the 2007 fiscal year and by KPMG LLP for the 2006 fiscal year included an audit of our consolidated financial statements, an audit of our internal control over financial reporting, audits of the financial statements of certain of our affiliates, review of our quarterly financial statements, review of debt and equity offerings and related consents and comfort letters, and professional services relating to tax compliance, tax planning, or tax advice.

The following table presents fees billed for audit services rendered (a) by PricewaterhouseCoopers LLP for the audit of annual consolidated financial statements for the year ended December 31, 2007, and fees billed for other services rendered by PricewaterhouseCoopers LLP during that period, and (b) by KPMG LLP for the audit of our annual consolidated financial statements for the year ended December 31, 2006, and fees billed for other services rendered by KPMG LLP during that period.

	PricewaterhouseCoopers LLP - 2007	KPMG LLP - 2006
Audit fees (1)	**$ 1,194,070**	$ 1,466,787
Audit-related fees (2)	**-**	352,135
Tax fees (3)	**950,342**	-
All other fees	**750**	-
Total	**$ 2,145,162**	$ 1,818,922

(1) Audit fees consisted of audit work performed in the preparation of financial statements and the audit of internal controls over financial reporting, fees for review of the interim unaudited financial statements included in our Quarterly Reports on Form 10-Q filed with the Securities and Exchange Commission, and fees for special procedures related to regulatory filings.
(2) Audit-related fees consisted principally of fees for audits of the financial statements of our affiliates.
(3) Tax fees consisted of fees for tax compliance, tax planning, or tax services, including preparation of our K-1 statements.

Audit Committee Policy on Services Provided by Independent Auditor

Consistent with SEC and NYSE policies regarding auditor independence, the Audit Committee has responsibility for appointing, setting compensation, and overseeing the work for the independent auditor. In recognition of this responsibility, the Audit Committee has established a policy with respect to the pre-approval of audit and permissible non-audit services provided by the independent auditor.

Prior to engagement of PricewaterhouseCoopers LLP as our independent auditor for the 2008 audit, a plan was submitted to and approved by the Audit Committee setting forth the services expected to be rendered during 2008 for each of the following four categories for its approval:

(1) audit services comprised of audit work performed in the preparation of financial statements and to attest and report on management's assessment of our internal controls over financial reporting, as well as work that only the independent auditor can reasonably be expected to provide, including quarterly review of our unaudited financial

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statements, comfort letters, statutory audits, attest services, consents and assistance with the review of documents filed with the SEC;

(2) audit related services comprised of assurance and related services that are traditionally performed by the independent auditor, including due diligence related to mergers and acquisitions, employee benefit plan audits and consultation regarding financial accounting and/or reporting standards;

(3) tax services comprised of tax compliance, tax planning, and tax advice; and

(4) all other permissible non-audit services, if any, that the Audit Committee believes are routine and recurring services that would not impair the independence of the auditor.

Audit fees are budgeted and the Audit Committee requires the independent auditor and management to report actual fees versus budgeted fees periodically during the year by category of service.

The Audit Committee may delegate pre-approval authority to one or more of its members. The member to whom such authority is delegated must report, for informational purposes only, any pre-approval decisions to the Audit Committee at its next scheduled meeting.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(1) Exhibits

2.1 Contribution Agreement by and among ONEOK, Inc., Northern Border Partners, L.P. and Northern Border Intermediate Limited Partnership dated February 14, 2006 (incorporated by reference to Exhibit 2.1 to Northern Border Partners, L.P.’s Form 10-K for the period ended December 31, 2005, filed on March 7, 2006 (File No. 1-12202)).

2.2 First Amendment to Contribution Agreement by and among ONEOK, Inc., Northern Border Partners, L.P. and Northern Border Intermediate Limited Partnership dated April 6, 2006 (incorporated by reference to Exhibit 2.2 to Northern Border Partners, L.P.’s Form 8-K filed on April 12, 2006 (File No. 1-12202)).

2.3 Purchase and Sale Agreement by and between ONEOK, Inc. and Northern Border Partners, L.P. dated February 14, 2006 (incorporated by reference to Exhibit 2.2 Northern Border Partners, L.P.’s Form 10-K for the period ended December 31, 2005, filed on March 7, 2006 (File No. 1-12202)).

2.4 First Amendment to Purchase and Sale Agreement by and among ONEOK, Inc., Northern Border Partners, L.P. and Northern Border Intermediate Limited Partnership dated April 6, 2006 (incorporated by reference to Exhibit 2.4 to Northern Border Partners, L.P.’s Form 8-K filed on April 12, 2006 (File No. 1-12202)).

2.5 Second Amendment to Contribution Agreement by and between ONEOK, Inc. and ONEOK Partners, L.P. dated January 16, 2007 (incorporated by reference to Exhibit 2.5 to ONEOK Partners, L.P.’s report on From 10-K for the year ended December 31, 2006 filed on March 1, 2007 (File No. 1-12202)).

2.6 Second Amendment to the Purchase and Sale Agreement by and between ONEOK, Inc. and ONEOK Partners, L.P. dated January 16, 2007 (incorporated by reference to Exhibit 2.6 to ONEOK Partners, L.P.’s report on From 10-K for the year ended December 31, 2006 filed on March 1, 2007 (File No. 1-12202)).

2.7 Partnership Interest Purchase and Sale Agreement by and between Northern Border Intermediate Limited Partnership and TC PipeLines Intermediate Limited Partnership dated as of December 31, 2005 (incorporated by reference to Exhibit 2.3 to Northern Border Partners, L.P.’s Form 10-K for the period ended December 31, 2005, filed on March 7, 2006 (File No. 1-12202)).

2.8 Purchase and Sale Agreement by and among Wisconsin Energy Corporation, WPS Investments, LLC and Northern Border Intermediate Limited Partnership dated as of March 30, 2006 (incorporated by reference to Exhibit 2.1 to Northern Border Partners, L.P.’s Form 8-K filed on March 30, 2006 (File No. 1-12202)).

2.9 Purchase and Sale Agreement by and between Williams Field Services Company, LLC and Northern Border Intermediate Limited Partnership dated as of May 2, 2006 (incorporated by reference to Exhibit 2.7 to ONEOK Partners, L.P.’s Form 10-Q for the period ended June 30, 2006, filed on August 4, 2006 (File No. 1-12202)).

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3.0 First Amendment to Purchase and Sale Agreement and Assignment, Delegation, Acceptance and Assumption of Rights and Obligations by and among Williams Field Services Company, LLC, ONEOK Partners Intermediate Limited Partnership and ONEOK Overland Pass Holdings, L.L.C. dated as of May 31, 2006 (incorporated by reference to Exhibit 2.8 to ONEOK Partners, L.P.'s Form 10-Q for the period ended June 30, 2006, filed on August 4, 2006 (File No. 1-12202)).

3.1 Northern Border Partners, L.P. Certificate of Limited Partnership dated July 12, 1993, Certificate of Amendment dated February 16, 2001, and Certificate of Amendment dated May 20, 2003 (incorporated by reference to Exhibit 3.1 to Northern Border Partners, L.P.'s Form 10-K for the year ended December 31, 2004, filed on March 14, 2005 (File No. 1-12202)).

3.2 Certificate of Amendment to Certificate of Limited Partnership of Northern Border Partners, L.P. dated May 17, 2006 (incorporated by reference to Exhibit 3.1 to ONEOK Partners, L.P.'s Form 8-K filed on May 23, 2006 (File No. 1-12202)).

3.3 Third Amended and Restated Agreement of Limited Partnership of ONEOK Partners, L.P. dated as of September 15, 2006 (incorporated by reference to Exhibit 3.1 to ONEOK Partners, L.P.'s Form 8-K filed on September 19, 2006 (File No. 1-12202)).

3.4 Certificate of Formation of ONEOK Partners GP, L.L.C., as amended, dated as of May 15, 2006 (incorporated by reference to Exhibit 3.5 to ONEOK Partners, L.P.'s Form 10-Q for the period ended June 30, 2006, filed on August 4, 2006 (File No. 1-12202)).

3.5 Second Amended and Restated Limited Liability Company Agreement of ONEOK Partners GP, L.L.C. effective May 17, 2006 (incorporated by reference to Exhibit 3.6 to ONEOK Partners, L.P.'s Form 10-Q for the period ended June 30, 2006, filed on August 4, 2006 (File No. 1-12202)).

3.6 Northern Border Intermediate Limited Partnership Certificate of Limited Partnership dated July 12, 1993, Certificate of Amendment dated February 16, 2001, and Certificate of Amendment dated May 20, 2003 (incorporated by reference to Exhibit 3.3 to Northern Border Partners, L.P.'s 10-K for the year ended December 31, 2004, filed on March 14, 2005 (File No 1-12202)).

3.7 Certificate of Amendment to Certificate of Limited Partnership of Northern Border Intermediate Limited Partnership dated May 17, 2006 (incorporated by reference to Exhibit 3.3 to ONEOK Partners, L.P.'s Form 8-K filed on May 23, 2006 (File No. 1-12202)).

3.8 Certificate of Amendment to Certificate of Limited Partnership of ONEOK Partners Intermediate Limited Partnership dated September 15, 2006 (incorporated by reference to Exhibit 3.2 to ONEOK Partners, L.P.'s Form 8-K filed on September 19, 2006 (File No. 1-12202)).

3.9 Second Amended and Restated Agreement of Limited Partnership of ONEOK Partners Intermediate Limited Partnership dated as of May 17, 2006 (incorporated by reference to Exhibit 3.4 to ONEOK Partners, L.P.'s Form 8-K filed on May 23, 2006 (File No. 1-12202)).

3.10 Amendment No. 1 to Second Amended and Restated Agreement of Limited Partnership of ONEOK Partners Intermediate Limited Partnership dated as of September 15, 2006 (incorporated by reference to Exhibit 3.3 to ONEOK Partners, L.P.'s Form 8-K filed on September 19, 2006 (File No. 1-12202)).

3.11 Certificate of Formation of ONEOK ILP GP, L.L.C. dated May 12, 2006 (incorporated by reference to Exhibit 4.11 to ONEOK Partners, L.P.'s Form S-3 filed on September 19, 2006 (File No. 333-137419)).

3.12 Limited Liability Company Agreement of ONEOK ILP GP, L.L.C. effective May 12, 2006 (incorporated by reference to Exhibit 4.12 to ONEOK Partners, L.P.'s Form S-3 filed on September 19, 2006 (File No. 333-137419)).

3.13 Amendment No. 1 to Third Amended and Restated Agreement of Limited Partnership of ONEOK Partners, L.P. dated July 20, 2007 (incorporated by reference to Exhibit 3.1 to ONEOK Partners, L.P.'s Form 10-Q filed on August 3, 2007 (File No. 1-12202)).

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4.1	Indenture, dated as of June 2, 2000, between Northern Border Partners, L.P., Northern Border Intermediate Limited Partnership and Bank One Trust Company, N.A., Trustee (incorporated by reference to Exhibit 4.1 to Northern Border Partners, L.P.'s Form 10-Q for the quarter ended June 30, 2000, filed on August 11, 2000 (File No. 1-12202)).
4.2	First Supplemental Indenture, dated as of September 14, 2000, between Northern Border Partners, L.P., Northern Border Intermediate Limited Partnership and Bank One Trust Company, N.A. (incorporated by reference to Exhibit 4.2 to Northern Border Partners, L.P.'s Form S-4 Registration Statement filed on September 20, 2000, (Registration No. 333-46212)).
4.3	Indenture, dated as of March 21, 2001, between Northern Border Partners, L.P. and Northern Border Intermediate Limited Partnership and Bank One Trust Company, N.A., Trustee (incorporated by reference to Exhibit 4.3 to Northern Border Partners, L.P.'s Form 10-K for the year ended December 31, 2001, filed on March 29, 2002 (File No. 1-12202)).
4.4	Indenture, dated as of September 25, 2006, between ONEOK Partners, L.P. and Wells Fargo Bank, N.A., as trustee (incorporated by reference to Exhibit 4.1 to ONEOK Partners, L.P.'s Form 8-K filed on September 26, 2006 (File No. 1-12202)).
4.5	First Supplemental Indenture, dated as of September 25, 2006, among ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and Wells Fargo Bank, N.A. , as trustee, with respect to the 5.90 percent Senior Notes due 2012 (incorporated by reference to Exhibit 4.2 to ONEOK Partners, L.P.'s Form 8-K filed on September 26, 2006 (File No. 1-12202)).
4.6	Second Supplemental Indenture, dated as of September 25, 2006, among ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and Wells Fargo Bank, N.A. , as trustee, with respect to the 6.15 percent Senior Notes due 2016 (incorporated by reference to Exhibit 4.3 to ONEOK Partners, L.P.'s Form 8-K filed on September 26, 2006 (File No. 1-12202)).
4.7	Third Supplemental Indenture, dated as of September 25, 2006, among ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and Wells Fargo Bank, N.A. , as trustee, with respect to the 6.65 percent Senior Notes due 2036 (incorporated by reference to Exhibit 4.4 to ONEOK Partners, L.P.'s Form 8-K filed on September 26, 2006 (File No. 1-12202)).
4.8	Form of Senior Note due 2012 (included in Exhibit 4.5 above).
4.9	Form of Senior Note due 2016 (included in Exhibit 4.6 above).
4.10	Form of Senior Note due 2036 (included in Exhibit 4.7 above).
4.11	Form of Class B unit certificate (incorporated by reference to Exhibit 4.1 to Northern Border Partners, L.P.'s Form 8-K filed on April 12, 2006 (File No. 1-12202)).
4.12	Form of common unit certificate (included in Exhibit 3.3 above).
4.13	Fourth Supplemental Indenture, dated as of September 28, 2007, among ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership and Wells Fargo Bank, N.A., as trustee, with respect to the 6.85 percent Senior Notes due 2037 (incorporated by reference to Exhibit 4.2 to ONEOK Partners, L.P.'s Form 8-K filed on September 28, 2007 (File No. 1-12202)).
4.14	Form of Senior Note due 2037 (included in Exhibit 4.13 above).
10.1	First Amended and Restated General Partnership Agreement of Northern Border Pipeline Company dated April 6, 2006 by and between Northern Border Intermediate Limited Partnership and TC PipeLines Intermediate Limited Partnership (incorporated by reference to Exhibit 3.1 to Northern Border Pipeline Company's Form 8-K filed April 12, 2006 (File No. 333-87753)).
10.2	Reorganization Agreement, dated September 15, 2006, by and among ONEOK Partners, L.P., ONEOK Partners Intermediate Limited Partnership, ONEOK Partners GP, L.L.C. and ONEOK ILP GP, L.L.C. (incorporated by reference to Exhibit 10.1 to ONEOK Partners, L.P.'s Form 8-K filed on September 19, 2006 (File No. 1-12202)).

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10.3	Services Agreement dated April 6, 2006, by and among ONEOK, Inc., Northern Plains Natural Gas Company, LLC, NBP Services, LLC, Northern Border Partners, L.P. and Northern Border Intermediate Limited Partnership (incorporated by reference to Exhibit 10.3 to Northern Border Partners, L.P.'s Form 8-K filed on April 12, 2006 (File No. 1-12202)).
10.4	Amended and Restated Revolving Credit Agreement dated March 30, 2006, among Northern Border Partners, L.P., the lenders from time to time party thereto, SunTrust Bank, as administrative agent, Wachovia Bank, National Association, as Syndication Agent; Bank of Montreal (doing business as Harris Nesbit), Barclays Bank PLC and Citibank, N.A., as Co-Documentation Agents (incorporated by reference to Exhibit 10.1 to Northern Border Partners, L.P. Form 8-K filed March 31, 2006 (File No. 1-12202)).
10.5	Form of Termination Agreement with ONEOK, Inc. dated as of January 5, 2005 (incorporated by reference to Exhibit 99.1 to Northern Border Partners, L.P.'s Form 8-K filed on January 11, 2005 (File No. 1-12202)).
10.6	Amended and Restated Limited Liability Company Agreement of Overland Pass Pipeline Company LLC entered into between ONEOK Overland Pass Holdings, L.L.C. and Williams Field Services Company, LLC dated May 31, 2006 (incorporated by reference to Exhibit 10.6 to ONEOK Partners, L.P.'s Form 10-Q for the period ended June 30, 2006, filed on August 4, 2006 (File No. 1-12202)).
10.7	Processing and Gathering Services Agreement between ONEOK Field Services Company, L.L.C, ONEOK, Inc. and ONEOK Bushton Processing, Inc. dated April 6, 2006 (incorporated by reference to Exhibit 10.7 to ONEOK Partners, L.P.'s Form 10-Q for the period ended June 30, 2006, filed on August 4, 2006 (File No. 1-12202)).
10.8	364-Day Credit Agreement dated April 6, 2006, by and among Northern Border Partners, L.P., the several banks and other financial institutions and lenders from time to time party thereto, SunTrust Bank, as Administrative Agent, Citicorp North America, Inc., as Syndication Agent, Bank of Montreal (doing business as Harris Nesbitt), UBS Loan Finance LLC, and Wachovia Bank, National Association, as Co-Documentation Agents (incorporated by reference to Exhibit 10.1 to ONEOK Partners, L.P.'s Form 8-K filed on April 12, 2006 (File No. 1-12202)).
10.9	First Amendment to Amended and Restated Revolving Credit Agreement among ONEOK Partner, L.P., the lenders from time to time party thereto, SunTrust Bank as administrative agent, Wachovia Bank, National Association, as syndication agent, and BMO Capital Markets Financing, Inc., Barclays Bank PLC and Citibank, N.A. as co-documentation agents, dated December 13, 2006 (incorporated by reference to Exhibit 10.9 to ONEOK Partners, L.P.'s report on From 10-K for the year ended December 31, 2006 filed on March 1, 2007 (File No. 1-12202)).
10.10	Amended and Restated Revolving Credit Agreement dated March 30, 2007, among ONEOK Partners, L.P., as Borrower, the lenders from time to time party thereto, SunTrust Bank, as Administrative Agent, Wachovia Bank, National Association, as Syndication Agent, and BMO Capital Markets, Barclays Bank PLC, and Citibank, N.A., as Co-Documentation Agents (incorporated by reference to Exhibit 10.1 to ONEOK Partners, L.P.'s report on Form 10-Q filed on May 2, 2007 (File No. 1-12202)).
10.11	Supplement and Joinder Agreement dated July 31, 2007, among ONEOK Partners, L.P., as Borrower, each of the existing Lenders, SunTrust Bank, as Administrative Agent, and JPMorgan Chase Bank, N.A. (incorporated by reference to Exhibit 10.1 to ONEOK Partners, L.P.'s report on Form 10-Q filed on August 3, 2007 (File No. 1-12202)).
10.12	Underwriting Agreement, dated September 25, 2007, among ONEOK Partners, L.P. and ONEOK Partners Intermediate Limited Partnership and Wachovia Capital Markets LLC, Greenwich Capital Markets, Inc., and UBS Securities LLC, as representatives of the several underwriters named therein (incorporated by reference to Exhibit 1.1 to ONEOK Partners, L.P.'s report on Form 8-K filed on September 28, 2007 (File No. 1-12202)).
12.1	Computation of Ratio of Earnings to Fixed Charges for the years ended December 31, 2007, 2006, 2005, 2004 and 2003.
16.1	Letter from KPMG LLP dated May 2, 2007, to the Securities and Exchange Commission regarding change in certifying accountant (incorporated by reference to Exhibit 16.1 to ONEOK Partners, L.P.'s report on Form 8-K filed on May 2, 2007 (File No. 1-12202)).
21	Required information concerning the registrant's subsidiaries.

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23.1 Consent of Independent Registered Public Accounting Firm - PricewaterhouseCoopers LLP.

23.2 Consent of Independent Registered Public Accounting Firm - KPMG LLP.

31.1 Certification of John W. Gibson pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.2 Certification of Curtis L. Dinan pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32.1 Certification of John W. Gibson pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished only pursuant to Rule 13a-14(b)).

32.2 Certification of Curtis L. Dinan pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished only pursuant to Rule 13a-14(b)).

(3) Financial Statement Schedules

All schedules have been omitted because of the absence of conditions under which they are required.

The total amount of securities of the Partnership authorized under any instrument with respect to long-term debt not filed as an exhibit does not exceed 10 percent of the total assets of the Partnership and its subsidiaries on a consolidated basis. The Partnership agrees, upon request of the Securities and Exchange Commission, to furnish copies of any or all of such instruments to the Securities and Exchange Commission.

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Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ONEOK Partners, L.P.
By: ONEOK Partners GP, L.L.C., its General Partner

Date: February 27, 2008

By: /s/ Curtis L. Dinan
Curtis L. Dinan
Senior Vice President,
Chief Financial Officer and Treasurer
(Signing on behalf of the Registrant
and as Principal Financial Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on this 27th day of February 2008.

/s/ John W. Gibson
John W. Gibson
Chariman of the Board, President and
Chief Executive Officer

/s/ Caron A. Lawhorn
Caron A. Lawhorn
Senior Vice President and
Chief Accounting Officer

/s/ Curtis L. Dinan
Curtis L. Dinan
Director

/s/ Jim Kneale
Jim Kneale
Director

/s/ Gil J. Van Lunsen
Gil J. Van Lunsen
Director

/s/ Gary N. Petersen
Gary N. Petersen
Director

/s/ Gerald B. Smith
Gerald B. Smith
Director

Section 2: EX-12.1 (COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES)

Exhibit 12.1

ONEOK Partners, L.P.

Computation of Ratio of Earnings to Fixed Charges

(Unaudited)	Twelve months ended December 31, 2003	2004	2005	2006	2007
	(Thousands of dollars)				
Fixed Charges, as defined					
Interest on long-term debt	$ 80,653	$ 79,020	$ 90,066	$136,533	$146,046
Other interest	45	15	3	439	4,714
Amortization of debt discount, premium & expense	(1,539)	(1,690)	(2,379)	(2,294)	1,765
Interest on lease agreements	1,210	1,192	1,522	5,605	6,392
Total Fixed Charges	80,369	78,537	89,212	140,283	158,917
Earnings before income taxes and undistributed income from equity investees	(49,244)	190,245	189,042	501,595	417,305
Earnings available for fixed charges	$ 31,125	$268,782	$278,254	$641,878	$576,222
Ratio of earnings to fixed charges	0.39**x**	3.42**x**	3.12**x**	4.58**x**	3.63**x**

For purposes of computing the ratio of earnings to combined fixed charges and preferred stock dividend requirements, "earnings" consists of income before cumulative effect of a change in accounting principle plus fixed charges, minority interest, income taxes and distributed income of equity method investees, less capitalized interest and undistributed income for equity investees. "Fixed charges" consists of interest expensed and capitalized, the amortization of debt discounts and issue costs and the representative interest portion of operating leases.

Section 3: EX-21 (REQUIRED INFORMATION CONCERNING THE REGISTRANT'S SUBSIDIARIES)

Exhibit 21

SUBSIDIARIES OF THE COMPANY

Subsidiaries of ONEOK Partners Intermediate Limited Partnership:

ONEOK Partners Intermediate Limited Partnership	Delaware
ONEOK ILP GP, L.L.C.	Delaware
Bear Paw Investments, LLC	Delaware
Bear Paw Energy, LLC	Delaware
Bear Paw Processing Company (Canada), Ltd.	Alberta
Brown Bear Enterprises, LLC	Delaware
Border Minnesota Pipeline, LLC	Delaware
Black Mesa Holdings, Inc.	Delaware
Black Mesa Pipeline, Inc.	Delaware
Black Mesa Pipeline Operations, L.L.C.	Delaware
Black Mesa Technologies, Inc.	Oklahoma
Black Mesa Technologies Services, LLC (60%)	Oklahoma
Border Midstream Services, Ltd.	Alberta
Border Midwestern Company	Delaware
Midwestern Gas Marketing Company	Delaware
Midwestern Gas Transmission Company	Delaware
Border Viking Company	Delaware
Viking Gas Transmission Company	Delaware
Crestone Energy Ventures, L.L.C.	Delaware
Crestone Bighorn, L.L.C.	Delaware
Crestone Gathering Services, L.L.C.	Delaware
Crestone Powder River, L.L.C.	Delaware
Crestone Wind River, L.L.C.	Delaware
Northern Border Pipeline Company (general partnership) (50%)	Texas
China Pipeline Holdings Ltd. (0.81%)	Cayman Islands
Guardian Pipeline, L.L.C.	Delaware
Bighorn Gas Gathering, L.L.C. (49.0%)	Delaware
Fort Union Gas Gathering, L.L.C. (37.04%)	Delaware
Lost Creek Gathering Company, L.L.C. (35%)	Delaware
Chisholm Pipeline Company (50%)	Delaware
Chisholm Pipeline Holdings, L.L.C.	Delaware
Mid Continent Market Center, L.L.C.	Kansas
OkTex Pipeline Company, L.L.C.	Delaware
ONEOK Arbuckle Pipeline, L.L.C.	Delaware
ONEOK Arbuckle Land Company	Texas
ONEOK Field Services Company, L.L.C.	Oklahoma
ONEOK Gas Gathering, L.L.C.	Oklahoma
ONEOK Gas Storage Holdings, L.L.C.	Delaware
ONEOK Gas Storage, L.L.C.	Oklahoma
ONEOK Gas Transportation, L.L.C.	Oklahoma
ONEOK Hydrocarbon, L.L.C.	Delaware

ONEOK Hydrocarbon, L.P.	Delaware
ONEOK Hydrocarbon GP, L.L.C.	Delaware
ONEOK Hydrocarbon Holdings, L.L.C.	Delaware
ONEOK Hydrocarbon Southwest, L.L.C.	Delaware
ONEOK MB I, L.P.	Delaware
ONEOK Midstream Gas Supply, L.L.C.	Oklahoma
ONEOK Mont Belvieu Storage Company, L.L.C.	Delaware
ONEOK NGL Pipeline, L.L.C.	Delaware
ONEOK NGL Gathering, L.L.C.	Delaware
ONEOK North System, L.L.C.	Delaware
ONEOK Overland Pass Holdings, L.L.C.	Oklahoma
ONEOK Pipeline Holdings, L.L.C.	Delaware
ONEOK Texas Gas Storage, L.L.C.	Texas
ONEOK Transmission Company, L.L.C.	Delaware
ONEOK Underground Storage Company, L.L.C.	Kansas
ONEOK VESCO Holdings, L.L.C.	Delaware
ONEOK WesTex Transmission, L.L.C.	Delaware
Overland Pass Pipeline Company LLC	Delaware
Potato Hills Gas Gathering System (joint venture) (51%)	Oklahoma
Sycamore Gas System (general partnership) (48.445%)	Oklahoma
Venice Energy Services Company, L.L.C. (10.1765%)	Delaware
Mont Belvieu I Fractionation Facility (joint venture)(80%)	Texas
Heartland Pipeline Company (general partnership) (50%)	Texas

Section 4: EX-23.1 (CONSENT OF PRICEWATERHOUSECOOPERS LLP)

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (No. 333-137419) and Form S-8 (Nos. 333-66949 and 333-72696) of ONEOK Partners, L.P. of our report dated February 27, 2008 relating to the financial statements and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

Tulsa, Oklahoma
February 27, 2008

Section 5: EX-23.2 (CONSENT OF KPMG LLP)

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors of ONEOK Partners GP, L.L.C. as General Partner of ONEOK Partners, L.P.:

We consent to the incorporation by reference in the registration statement (Nos. 333-66949 and 333-72696) on Form S-8 and (Nos. 333-137419) on Form S-3 of ONEOK Partners, L.P. (the Partnership) of our report dated February 28, 2007 except for Note J as to which the date is February 27, 2008, with respect to the consolidated balance sheet of the Partnership, as of December 31, 2006 and the related consolidated statements of income, cash flows, and changes in partners' equity and comprehensive income for each of the years in the two-year period ended December 31, 2006, which report appears in the December 31, 2007, annual report on Form 10-K of the Partnership.

/s/ KPMG LLP

February 27, 2008
Tulsa, OK

Section 6: EX-31.1 (SECTION 302 CEO CERTIFICATION)

Exhibit 31.1

Certification

I, John W. Gibson, certify that:

I have reviewed this annual report on Form 10-K of ONEOK Partners, L.P.;

Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 27, 2008

/s/ John W. Gibson
John W. Gibson
Chief Executive Officer

Section 7: EX-31.2 (SECTION 302 CFO CERTIFICATION)

Exhibit 31.2

Certification

I, Curtis L. Dinan, certify that:

I have reviewed this annual report on Form 10-K of ONEOK Partners, L.P.;

Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 27, 2008

/s/ Curtis L. Dinan
Curtis L. Dinan
Chief Financial Officer

Section 8: EX-32.1 (SECTION 906 CEO CERTIFICATION)

Exhibit 32.1

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report on Form 10-K of ONEOK Partners, L.P. (the "Company") for the period ending December 31, 2007 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, John W. Gibson, Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) the Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ John W. Gibson
John W. Gibson
Chief Executive Officer

February 27, 2008

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to ONEOK Partners, L.P. and will be retained by ONEOK Partners, L.P. and furnished to the Securities and Exchange Commission or its staff upon request.

Section 9: EX-32.2 (SECTION 906 CFO CERTIFICATION)

Exhibit 32.2

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report on Form 10-K of ONEOK Partners, L.P. (the "Company") for the period ending December 31, 2007 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Curtis L. Dinan, Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) the Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Curtis L. Dinan
Curtis L. Dinan
Chief Financial Officer

February 27, 2008

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to ONEOK Partners, L.P. and will be retained by ONEOK Partners, L.P. and furnished to the Securities and Exchange Commission or its staff upon request.

10-Q 1 d10q.htm FORM 10-Q FOR QUARTERLY PERIOD ENDED SEPTEMBER 30, 2008

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

x **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended September 30, 2008

or

¨ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from   to

Commission file number 1-33007

SPECTRA ENERGY CORP
(Exact Name of Registrant as Specified in its Charter)

Delaware	**20-5413139**
(State or other jurisdiction of incorporation)	**(IRS Employer Identification No.)**

5400 Westheimer Court
Houston, Texas 77056
(Address of principal executive offices, including zip code)

713-627-5400
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.   Yes x   No ¨

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer," and "smaller reporting company" in Rule 12b-2 of Exchange Act.

Large accelerated filer x   Accelerated filer ¨   Non-accelerated filer ¨   Smaller reporting company ¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).   Yes ¨   No x

Number of shares of Common Stock, $0.001 par value, outstanding as of October 31, 2008: 611,049,032

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SPECTRA ENERGY CORP
FORM 10-Q FOR THE QUARTER ENDED
September 30, 2008

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This document includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements are based on management's beliefs and assumptions. These forward-looking statements are identified by terms and phrases such as anticipate, believe, intend, estimate, expect, continue, should, could, may, plan, project, predict, will, potential, forecast, and similar expressions. Forward-looking statements involve risks and uncertainties that may cause actual results to be materially different from the results predicted. Factors that could cause actual results to differ materially from those indicated in any forward-looking statement include, but are not limited to:

- state, federal and foreign legislative and regulatory initiatives that affect cost and investment recovery, have an effect on rate structure, and affect the speed at and degree to which competition enters the natural gas industries;
- outcomes of litigation and regulatory investigations, proceedings or inquiries;
- weather and other natural phenomena, including the economic, operational and other effects of hurricanes and storms;
- the timing and extent of changes in commodity prices, interest rates and foreign currency exchange rates;
- general economic conditions, including any potential effects arising from terrorist attacks and any consequential or other hostilities;
- changes in environmental, safety and other laws and regulations;
- results of financing efforts, including the ability to obtain financing on favorable terms, which can be affected by various factors, including credit ratings and general market and economic conditions;
- increases in the cost of goods and services required to complete capital projects;
- declines in the market prices of equity and debt securities and resulting funding requirements for defined benefit pension plans;
- growth in opportunities, including the timing and success of efforts to develop domestic and international pipeline, storage, gathering, processing and other infrastructure projects and the effects of competition;
- the performance of natural gas transmission and storage, distribution, and gathering and processing facilities;
- the extent of success in connecting natural gas supplies to gathering, processing and transmission systems and in connecting to expanding gas markets;
- the effect of accounting pronouncements issued periodically by accounting standard-setting bodies;
- conditions of the capital markets during the periods covered by the forward-looking statements; and
- the ability to successfully complete merger, acquisition or divestiture plans; regulatory or other limitations imposed as a result of a merger, acquisition or divestiture; and the success of the business following a merger, acquisition or divestiture.

In light of these risks, uncertainties and assumptions, the events described in the forward-looking statements might not occur or might occur to a different extent or at a different time than Spectra Energy Corp has described. Spectra Energy Corp undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements.

SPECTRA ENERGY CORP
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)
(In millions, except per-share amounts)

	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
Operating Revenues				
Transportation, storage and processing of natural gas	$ 586	$ 557	$ 1,764	$ 1,616
Distribution of natural gas	213	207	1,239	1,161
Sales of natural gas liquids	219	127	623	371
Other	62	59	187	169
Total operating revenues	1,080	950	3,813	3,317
Operating Expenses				
Natural gas and petroleum products purchased	231	164	1,127	963
Operating, maintenance and other	304	276	919	797
Depreciation and amortization	144	135	437	382
Property and other taxes	61	50	186	139
Total operating expenses	740	625	2,669	2,281
Gains on Sales of Other Assets and Other, net	—	5	32	6
Operating Income	340	330	1,176	1,042
Other Income and Expenses				
Equity in earnings of unconsolidated affiliates	273	175	725	394
Other income and expenses, net	9	11	30	37
Total other income and expenses	282	186	755	431
Interest Expense	163	156	470	467
Minority Interest Expense	15	15	46	41
Earnings From Continuing Operations Before Income Taxes	444	345	1,415	965
Income Tax Expense From Continuing Operations	145	110	453	312
Income From Continuing Operations	299	235	962	653
Income (Loss) From Discontinued Operations, net of tax	(3)	3	(4)	17
Income Before Extraordinary Items	296	238	958	670
Extraordinary Items, net of tax	—	(4)	—	(4)
Net Income	$ 296	$ 234	$ 958	$ 666
Common Stock Data				
Weighted-average shares outstanding				
Basic	615	632	626	632
Diluted	617	635	629	635
Earnings per share from continuing operations				
Basic	$ 0.49	$ 0.37	$ 1.54	$ 1.03
Diluted	$ 0.48	$ 0.37	$ 1.53	$ 1.03
Earnings per share—total				
Basic	$ 0.48	$ 0.37	$ 1.53	$ 1.05
Diluted	$ 0.48	$ 0.37	$ 1.52	$ 1.05
Dividends per share	$ 0.25	$ 0.22	$ 0.71	$ 0.66

See Notes to Condensed Consolidated Financial Statements

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SPECTRA ENERGY CORP
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)
(In millions)

	September 30, 2008	December 31, 2007
ASSETS		
Current Assets		
Cash and cash equivalents	$ 281	$ 94
Receivables, net	795	907
Inventory	470	287
Assets held for sale	123	—
Other	149	91
Total current assets	1,818	1,379
Investments and Other Assets		
Investments in and loans to unconsolidated affiliates	2,089	1,780
Goodwill	3,767	3,948
Other	516	631
Total investments and other assets	6,372	6,359
Property, Plant and Equipment		
Cost	18,490	18,154
Less accumulated depreciation and amortization	4,129	3,854
Net property, plant and equipment	14,361	14,300
Regulatory Assets and Deferred Debits	956	932
Total Assets	$ 23,507	$ 22,970

See Notes to Condensed Consolidated Financial Statements

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SPECTRA ENERGY CORP
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)
(In millions, except per-share amounts)

	September 30, 2008	December 31, 2007
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	$ 349	$ 363
Short-term borrowings and commercial paper	913	715
Taxes accrued	145	85
Interest accrued	160	146
Current maturities of long-term debt	221	338
Other	767	775
Total current liabilities	2,555	2,422
Long-term Debt	9,369	8,345
Deferred Credits and Other Liabilities		
Deferred income taxes	2,894	2,883
Regulatory and other	1,567	1,657
Total deferred credits and other liabilities	4,461	4,540
Commitments and Contingencies		
Minority Interests	701	806
Stockholders' Equity		
Preferred stock, $0.001 par, 22 million shares authorized, no shares outstanding	—	—
Common stock, $0.001 par, 1 billion shares authorized, 611 million and 632 million shares outstanding at September 30, 2008 and December 31, 2007, respectively	1	1
Additional paid-in capital	4,098	4,658
Retained earnings	882	368
Accumulated other comprehensive income	1,440	1,830
Total stockholders' equity	6,421	6,857
Total Liabilities and Stockholders' Equity	$ 23,507	$ 22,970

See Notes to Condensed Consolidated Financial Statements

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SPECTRA ENERGY CORP
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)
(In millions)

	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 958	$ 666
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	445	393
Deferred income tax expense	61	157
Minority interest expense	46	49
Equity in earnings of unconsolidated affiliates	(725)	(394)
Distributions received from unconsolidated affiliates	691	379
Other	(80)	(398)
Net cash provided by operating activities	1,396	852
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures	(1,038)	(779)
Investments in and loans to unconsolidated affiliates	(497)	(161)
Acquisition of Spectra Energy Income Fund	(274)	—
Purchases of available-for-sale securities	(1,289)	(1,181)
Proceeds from sales and maturities of available-for-sale securities	1,354	978
Distributions received from unconsolidated affiliates	180	—
Other	—	26
Net cash used in investing activities	(1,564)	(1,117)
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from the issuance of long-term debt	2,972	720
Payments for the redemption of long-term debt	(1,801)	(487)
Net increase in short-term borrowings and commercial paper	204	19
Distributions to minority interests	(50)	(36)
Contributions from minority interests	112	—
Proceeds from Spectra Energy Partners, LP initial public offering	—	230
Repurchases of Spectra Energy common shares	(600)	—
Dividends paid	(444)	(418)
Other	(39)	11
Net cash provided by financing activities	354	39
Effect of exchange rate changes on cash	1	62
Net increase (decrease) in cash and cash equivalents	187	(164)
Cash and cash equivalents at beginning of period	94	299
Cash and cash equivalents at end of period	$ 281	$ 135

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SPECTRA ENERGY CORP
CONDENSED CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(Unaudited)
(In millions)

	Common Stock	Additional Paid-in Capital	Retained Earnings	Member's Equity	Accumulated Other Comprehensive Income: Foreign Currency Translation Adjustments	Accumulated Other Comprehensive Income: Net Gains (Losses) on Cash Flow Hedges	Accumulated Other Comprehensive Income: Other	Total
December 31, 2007	$ 1	$ 4,658	$ 368	$ —	$ 2,033	$ (8)	$ (195)	$6,857
Net income	—	—	958	—	—	—	—	958
Foreign currency translation adjustments	—	—	—	—	(411)	—	—	(411)
Unrealized mark-to-market net loss on hedges	—	—	—	—	—	(9)	—	(9)
Reclassification of cash flow hedges into earnings	—	—	—	—	—	1	—	1
Pension and benefits impact of SFAS 158	—	—	—	—	—	—	29	29
Common stock repurchases	—	(600)	—	—	—	—	—	(600)
Dividends on common stock	—	—	(444)	—	—	—	—	(444)
Stock-based compensation	—	32	—	—	—	—	—	32
Other	—	8	—	—	—	—	—	8
September 30, 2008	$ 1	$ 4,098	$ 882	$ —	$ 1,622	$ (16)	$ (166)	$6,421
December 31, 2006	$ —	$ —	$ —	$ 4,598	$ 1,156	$ (6)	$ (109)	$5,639
Conversion to Spectra Energy Corp	1	4,597	—	(4,598)	—	—	—	—
Net income	—	—	666	—	—	—	—	666
Foreign currency translation adjustments	—	—	—	—	910	—	—	910
Reclassification of cash flow hedges into earnings	—	—	—	—	—	(2)	—	(2)
Pension and benefits impact of SFAS 158	—	—	(5)	—	—	—	26	21
FIN 48 implementation	—	—	(26)	—	—	—	—	(26)
Transfer of net assets and liabilities from Duke Energy	—	8	—	—	—	—	(100)	(92)
Dividends on common stock	—	—	(418)	—	—	—	—	(418)
Stock-based compensation	—	11	—	—	—	—	—	11
September 30, 2007	$ 1	$ 4,616	$ 217	$ —	$ 2,066	$ (8)	$ (183)	$6,709

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SPECTRA ENERGY CORP
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. General

Nature of Operations. Spectra Energy Corp, through its subsidiaries and equity affiliates (collectively, Spectra Energy), owns and operates a large and diversified portfolio of complementary natural gas-related energy assets. Spectra Energy operates in three key areas of the natural gas industry: gathering and processing, transmission and storage, and distribution. Spectra Energy provides transportation and storage of natural gas to customers in various regions of the northeastern and southeastern United States, the Maritime Provinces in Canada and the Pacific Northwest in the United States and Canada, and in the province of Ontario, Canada. Spectra Energy also provides natural gas sales and distribution services to retail customers in Ontario, and natural gas gathering and processing services to customers in Western Canada. In addition, Spectra Energy owns a 50% interest in DCP Midstream, LLC (DCP Midstream), one of the largest natural gas gatherers and processors in the United States.

Basis of Presentation. The Condensed Consolidated Financial Statements include the accounts of Spectra Energy Corp, its majority-owned subsidiaries where Spectra Energy has control and those variable interest entities, if any, where Spectra Energy is the primary beneficiary. These interim financial statements should be read in conjunction with the consolidated financial statements included in Spectra Energy's Annual Report on Form 10-K for the year ended December 31, 2007, and reflect all normal recurring adjustments that are, in the opinion of management, necessary to fairly present Spectra Energy's results of operations and financial position. Amounts reported in the Condensed Consolidated Statements of Operations are not necessarily indicative of amounts expected for the respective annual periods due to the effects of seasonal temperature variations on energy consumption, primarily in the gas distribution operations of Spectra Energy, as well as changing commodity prices on certain of the processing operations and other factors.

Use of Estimates. To conform with generally accepted accounting principles (GAAP) in the United States, management makes estimates and assumptions that affect the amounts reported in the Condensed Consolidated Financial Statements and Notes to Condensed Consolidated Financial Statements. Although these estimates are based on management's best available knowledge at the time, actual results could differ.

Recasts and Reclassifications. The Condensed Consolidated Statements of Operations and all related information contained in this report have been re-cast to reflect the operating results of certain natural gas gathering and processing facilities within the Western Canada Transmission & Processing segment as discontinued operations for all periods presented. See Note 7 for further discussion. In addition, the components of Operating Revenues on the Condensed Consolidated Statement of Operations for the 2007 periods have been reclassified to conform to the current reporting presentation.

Spin-off from Duke Energy Corporation. In conjunction with the spin-off of Spectra Energy from Duke Energy Corporation (Duke Energy) on January 2, 2007, Duke Energy transferred to Spectra Energy the assets and liabilities, including related tax effects, associated with Spectra Energy's employee benefits and captive insurance positions, as well as miscellaneous corporate assets and liabilities. The net effect of these non-cash transfers during the nine-month period ended September 30, 2007 is reflected as an increase of $8 million to Additional Paid-in Capital and a decrease of $100 million to Accumulated Other Comprehensive Income in the Condensed Consolidated Statements of Stockholders' Equity.

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2. Acquisitions and Dispositions

Acquisition—Spectra Energy Income Fund. On May 1, 2008, Westcoast Energy Inc. (Westcoast), a subsidiary of Spectra Energy, acquired the 24.4 million units of the Spectra Energy Income Fund (Income Fund) that were held by non-affiliated holders at a purchase price of 11.25 Canadian dollars per unit, for a total purchase price of 279 million Canadian dollars (approximately $274 million). Westcoast now owns 100% of the Midstream operations. Prior to the acquisition, the Income Fund indirectly held 54% of Spectra Energy's consolidated Midstream operations and Westcoast indirectly held the remaining 46%. The Income Fund is included in the Western Canada Transmission & Processing business segment. The transaction, primarily driven by changes in Canadian federal tax rules as related to income trusts, was accounted for as a step acquisition, using the purchase method of accounting in accordance with Statement of Financial Accounting Standards (SFAS) No. 141, "Business Combinations."

The following table summarizes the preliminary fair values of the assets acquired and liabilities assumed as of May 1, 2008. The amount assigned to Goodwill increased $17 million from the amount estimated at June 30, 2008. Subsequent adjustments may be recorded upon the completion of the valuation and the final determination of the purchase price allocation.

	Purchase Price Allocation (in millions)
Purchase price	$ 274
Current assets	20
Property, plant and equipment, net	340
Current liabilities	(11)
Long-term debt (intercompany)	(89)
Deferred credits and other liabilities	(9)
Deferred income taxes	(43)
Total assets acquired/liabilities assumed	208
Goodwill	$ 66

Disposition—Saltville Gas Storage Company L.L.C. and P-25 pipeline. In April 2008, Spectra Energy completed the sale of Saltville Gas Storage Company L.L.C. and the P-25 pipeline to Spectra Energy Partners, LP (Spectra Energy Partners) for $107 million. Proceeds from the sale consisted of 4,207,641 Spectra Energy Partners common units, 85,870 general partner units and $5 million in cash. Spectra Energy's ownership of Spectra Energy Partners increased from 83% to 84% as a result of the issuance of the new common and general partner units. No gain or loss was recognized on the disposition since this transaction represented a transfer of entities under common control.

3. Business Segments

Spectra Energy manages its business in four reportable segments: U.S. Transmission, Distribution, Western Canada Transmission & Processing and Field Services. The remainder of Spectra Energy's business operations is presented as "Other," and consists of unallocated corporate costs, wholly owned captive insurance subsidiaries, employee benefit plan assets and liabilities, and other miscellaneous activities.

Spectra Energy's chief operating decision maker regularly reviews financial information about each of these business units in deciding how to allocate resources and evaluate performance. All of the business units are considered reportable segments under SFAS No. 131, "Disclosures about Segments of an Enterprise and Related Information." There is no aggregation within Spectra Energy's defined business segments.

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U.S. Transmission provides transportation and storage of natural gas for customers in various regions of the eastern and southeastern United States and the Maritime Provinces in Canada. The natural gas transmission and storage operations in the U.S. are primarily subject to the Federal Energy Regulatory Commission's (FERC's) rules and regulations.

Distribution provides retail natural gas distribution service in Ontario, as well as natural gas transportation and storage services to other utilities and energy market participants. These services are provided by Union Gas Limited (Union Gas), and are primarily subject to the rules and regulations of the Ontario Energy Board (OEB).

Western Canada Transmission & Processing provides transportation of natural gas, natural gas gathering and processing services, and natural gas liquids (NGLs) extraction, fractionation, transportation, storage and marketing to customers in western Canada and the northern tier of the United States. This segment conducts business primarily through the BC Pipeline and BC Field Services operations, the Empress System and the Midstream business, which includes the Income Fund discussed in Note 2. The BC Pipeline and BC Field Services operations are primarily subject to the rules and regulations of Canada's National Energy Board (NEB).

Field Services gathers and processes natural gas and fractionates, markets and trades NGLs. It conducts operations through DCP Midstream, which is owned 50% by Spectra Energy and 50% by ConocoPhillips. Field Services gathers raw natural gas through gathering systems located in eight major natural gas producing regions: Mid-Continent, Rocky Mountains, East Texas-North Louisiana, Barnett Shale, Gulf Coast, South Texas, Central Texas, and Permian Basin.

Spectra Energy's reportable segments offer different products and services and are managed separately as business units. Management evaluates segment performance based on earnings before interest and taxes (EBIT) from continuing operations, after deducting minority interest expense related to those profits.

On a segment basis, EBIT excludes discontinued operations, represents all profits from continuing operations (both operating and non-operating) before deducting interest and taxes, and is net of the minority interest expense related to those profits. Cash, cash equivalents and short-term investments are managed centrally by Spectra Energy, so the associated realized and unrealized gains and losses from foreign currency transactions, and interest and dividend income on those balances are excluded from the segments' EBIT.

Transactions between reportable segments are accounted for on the same basis as with unaffiliated third parties.

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Business Segment Data (a)

	Unaffiliated Revenues	Intersegment Revenues	Total Revenues	Segment EBIT/ Consolidated Earnings from Continuing Operations before Income Taxes
			(in millions)	
Three Months Ended September 30, 2008				
U.S. Transmission	$ 401	$ 1	$ 402	$ 213
Distribution	280	—	280	44
Western Canada Transmission & Processing	397	—	397	113
Field Services	—	—	—	239
Total reportable segments	1,078	1	1,079	609
Other	2	9	11	(9)
Eliminations	—	(10)	(10)	—
Interest expense	—	—	—	(163)
Interest income and other (b)	—	—	—	7
Total consolidated	$ 1,080	$ —	$ 1,080	$ 444
Three Months Ended September 30, 2007				
U.S. Transmission	$ 384	$ 2	$ 386	$ 230
Distribution	266	—	266	40
Western Canada Transmission & Processing	298	—	298	101
Field Services	—	—	—	140
Total reportable segments	948	2	950	511
Other	2	6	8	(15)
Eliminations	—	(8)	(8)	—
Interest expense	—	—	—	(156)
Interest income and other (b)	—	—	—	5
Total consolidated	$ 950	$ —	$ 950	$ 345
Nine Months Ended September 30, 2008				
U.S. Transmission	$ 1,202	$ 3	$ 1,205	$ 683
Distribution	1,433	—	1,433	263
Western Canada Transmission & Processing	1,174	—	1,174	333
Field Services	—	—	—	647
Total reportable segments	3,809	3	3,812	1,926
Other	4	28	32	(57)
Eliminations	—	(31)	(31)	—
Interest expense	—	—	—	(470)
Interest income and other (b)	—	—	—	16
Total consolidated	$ 3,813	$ —	$ 3,813	$ 1,415
Nine Months Ended September 30, 2007				
U.S. Transmission	$ 1,129	$ 4	$ 1,133	$ 673
Distribution	1,330	—	1,330	238
Western Canada Transmission & Processing	852	—	852	218
Field Services	—	—	—	345
Total reportable segments	3,311	4	3,315	1,474
Other	6	17	23	(56)
Eliminations	—	(21)	(21)	—
Interest expense	—	—	—	(467)
Interest income and other (b)	—	—	—	14
Total consolidated	$ 3,317	$ —	$ 3,317	$ 965

(a) Segment results exclude discontinued operations.
(b) Other includes foreign currency transaction gains and losses, additional minority interest expense not allocated to the segment results and intersegment eliminations.

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4. Regulatory Matters

The following is a summary of recent regulatory matters. Management believes the impacts of these matters will not have a material adverse effect on Spectra Energy's future consolidated results of operations, financial position or cash flows.

Union Gas. Union Gas has rates that are approved by the OEB. Final 2008 rates, reflecting the incentive regulation settlement agreement accepted by the OEB on January 17, 2008, were implemented April 1, 2008, retroactive to January 1, 2008.

In November 2006, Union Gas received a decision from the OEB on the regulation of rates for gas storage services in Ontario (the Storage Forbearance Decision). The OEB determined that it would not regulate the rates for storage services to customers outside Union Gas' franchise area or the rates for new storage services to customers within its franchise area. The Storage Forbearance Decision requires Union Gas to continue to share long-term storage margin with ratepayers over a four-year phase-out period that started in 2007.

In March 2008, Union Gas applied to the OEB for the annual disposition of its 2007 non-commodity deferral account balances. The OEB issued its decision on this application in June 2008 finding that Union Gas should share revenue on all long-term storage contracts. Union Gas had previously interpreted the Storage Forbearance Decision to apply only to those contracts that were in existence as of the date of the Storage Forbearance Decision. Union Gas appealed this decision, and the OEB denied the appeal in October 2008. Union Gas recorded a $15 million charge to Transportation, Storage and Processing of Natural Gas operating revenues on the Condensed Consolidated Statement of Operations in the second quarter of 2008 as a result of the June 2008 decision.

BC Pipeline. The existing two-year BC Pipeline settlement agreement reached with customers and approved by the NEB expired on December 31, 2007. In December 2007, the NEB approved 2008 interim transportation tolls. In May 2008, the NEB approved BC Pipeline's application requesting the approval of 2008 revised interim tolls effective June 1, 2008. BC Pipeline and its customers recently reached an agreement regarding the determination of final tolls for transmission services for 2008, 2009 and 2010. The NEB approved this settlement agreement on November 4, 2008.

Maritimes & Northeast Pipeline Limited Partnership (M&N LP). In 2007, M&N LP operated under an NEB-approved toll settlement that expired December 31, 2007. A toll settlement agreement for the 2008 fiscal year was approved by the NEB in January 2008.

5. Gains on the Sales of Other Assets and Other, net

In the second quarter of 2008, Spectra Energy's U.S. Transmission segment received shares of stock as consideration for a customer bankruptcy settlement and recorded a gain of $31 million ($21 million after tax) which is reflected in Gains on Sales of Other Assets and Other, Net in the Condensed Consolidated Statements of Operations. The stock was subsequently sold in July 2008, resulting in net proceeds of $27 million, reflected in Cash Flows from Operating Activities on the Condensed Consolidated Statements of Cash Flows, and a loss of $4 million recorded as Other Income and Expenses, Net.

6. Income Taxes

Income tax expense from continuing operations for the three and nine-month periods ended September 30, 2008 was $145 million and $453 million, respectively, compared to $110 million and $312 million reported in the same periods in 2007, increasing primarily as a result of higher earnings in 2008.

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The effective tax rate for income from continuing operations for the three months ended September 30, 2008 was 32.7% as compared to 31.9% for the same period in 2007. The lower effective tax rate in the prior period was primarily a result of an adjustment in the 2007 period for final 2006 tax returns in Canada. The effective tax rate for the nine months ended September 30, 2008 was 32.0% as compared to 32.3% for the same period of 2007.

Spectra Energy recognized no material changes in unrecognized tax benefits during the three and nine-month periods ended September 30, 2008. Although uncertain, Spectra Energy believes it is reasonably possible that the total amount of unrecognized tax benefits could decrease by approximately $14 million prior to September 30, 2009. The anticipated changes in unrecognized tax benefits relate to expected audit settlements focused primarily on classification of certain tax attributes, transfer pricing and expiration of statutes of limitations.

7. Discontinued Operations

On October 7, 2008, Spectra Energy entered into an agreement to sell its interests in the Nevis and Brazeau River natural gas gathering and processing facilities, which are part of the Western Canada Transmission & Processing segment. Subject to receipt of required regulatory approvals and certain other conditions, the transaction is expected to close in the fourth quarter of 2008. Assets associated with these operations, totaling $123 million at September 30, 2008, are classified as Assets Held for Sale on the Condensed Consolidated Balance Sheet, and associated liabilities totaling $11 million are classified within Other Current Liabilities. Results of operations of these assets are reflected as discontinued operations in the Condensed Consolidated Statements of Operations for all periods presented.

In the second quarter of 2007, Spectra Energy LNG Sales, Inc. (Spectra Energy LNG) reached a settlement agreement related to an arbitration proceeding regarding Spectra Energy LNG's claims for the period prior to May 2002 under certain liquefied natural gas (LNG) transportation contracts with Sonatrach and Sonatrading, and Spectra Energy LNG received $18 million, which resulted in $11 million in Income (Loss) From Discontinued Operations, Net of Tax on the Condensed Consolidated Statements of Operations. In June 2008, the parties entered into a settlement agreement under which Spectra Energy LNG's claims for the period after May 2002 were satisfied pursuant to commercial transactions involving the purchase of propane from Sonatrach. Spectra Energy entered into associated agreements with an affiliate of DCP Midstream and another party for the sale of these propane volumes. Net purchases and sales of propane under these arrangements are reflected as discontinued operations.

In the third quarter of 2007, Spectra Energy recorded $3 million of income ($3 million, net of tax), classified as Income (Loss) From Discontinued Operations, Net of Tax, related to a settlement of a sales price contingency associated with the 2005 sale of a natural gas gathering facility that was associated with Duke Energy North America (DENA), which is classified within the "Other" segment.

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The following table summarizes the results classified as Income From Discontinued Operations, Net of Tax, in the Consolidated Statements of Operations.

	Operating Revenues	Pre-tax Earnings (Loss)	Income Tax Expense (Benefit)	Income (Loss) From Discontinued Operations, Net of Tax
		(in millions)		
Three Months Ended September 30, 2008				
Western Canada Transmission & Processing	$ 7	$ (3)	$ —	$ (3)
Other	29	—	—	—
Total consolidated	$ 36	$ (3)	$ —	$ (3)
Three Months Ended September 30, 2007				
Western Canada Transmission & Processing	$ 10	$ 2	$ 2	$ —
Other	—	3	—	3
Total consolidated	$ 10	$ 5	$ 2	$ 3
Nine Months Ended September 30, 2008				
Western Canada Transmission & Processing	$ 23	$ (5)	$ (1)	$ (4)
Other	59	1	1	—
Total consolidated	$ 82	$ (4)	$ —	$ (4)
Nine Months Ended September 30, 2007				
Western Canada Transmission & Processing	$ 28	$ 6	$ 3	$ 3
Other	—	21	7	14
Total consolidated	$ 28	$ 27	$ 10	$ 17

8. Comprehensive Income

Comprehensive income includes net income and all other non-owner changes in equity. Components of comprehensive income are as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
		(in millions)		
Net income	$ 296	$ 234	$ 958	$ 666
Other comprehensive income (loss)				
Foreign currency translation adjustments	(266)	432	(411)	910
Unrealized mark-to-market net loss on hedges (a)	(23)	—	(9)	—
Reclassification of cash flow hedges into earnings (b)	1	(3)	1	(2)
Pension and benefits impact of SFAS 158 (c)	3	—	29	—
Other comprehensive income (loss), net of tax	(285)	429	(390)	908
Total comprehensive income	$ 11	$ 663	$ 568	$ 1,574

(a) Net of $9 million and $6 million of tax benefits for the three and nine months ended September 30, 2008, respectively.
(b) Net of $1 million of tax expense for both the three and nine months ended September 30, 2008 and net of less than a $1 million tax benefit for both the three and nine months ended September 30, 2007.
(c) Includes $1 million of tax expense and $14 million of tax benefits for the three and nine months ended September 30, 2008, respectively.

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9. Earnings per Common Share

Basic earnings per common share (EPS) is computed by dividing net income by the weighted-average number of common shares outstanding during the period. Diluted EPS is computed by dividing net income by the diluted weighted-average number of common shares outstanding during the period. Diluted EPS reflects the potential dilution that could occur if securities or other agreements to issue common stock, such as stock options, stock-based performance unit awards and phantom stock awards, were exercised, settled or converted into common stock.

The following table presents Spectra Energy's basic and diluted EPS calculations:

	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
	(in millions, except per-share amounts)			
Income from continuing operations	$ 299	$ 235	$ 962	$ 653
Income (loss) from discontinued operations, net of tax	(3)	3	(4)	17
Extraordinary items, net of tax	—	(4)	—	(4)
Net income	$ 296	$ 234	$ 958	$ 666
Weighted average common shares, outstanding				
Basic	615	632	626	632
Diluted	617	635	629	635
Basic earnings per common share				
Continuing operations	$ 0.49	$ 0.37	$ 1.54	$ 1.03
Discontinued operations, net of tax	(0.01)	0.01	(0.01)	0.03
Extraordinary items, net of tax	—	(0.01)	—	(0.01)
Total basic earnings per common share	$ 0.48	$ 0.37	$ 1.53	$ 1.05
Diluted earnings per common share				
Continuing operations	$ 0.48	$ 0.37	$ 1.53	$ 1.03
Discontinued operations, net of tax	—	0.01	(0.01)	0.03
Extraordinary items, net of tax	—	(0.01)	—	(0.01)
Total diluted earnings per common share	$ 0.48	$ 0.37	$ 1.52	$ 1.05

Weighted-average shares used to calculate diluted EPS includes the effect of certain options and restricted stock awards. Certain other options and stock awards related to approximately six million and nine million shares for the three months ended September 30, 2008 and 2007, respectively, and seven million and eight million shares for the nine months ended September 30, 2008 and 2007, respectively, were not included in the calculation of diluted EPS because either the option exercise prices were greater than the average market price of the shares during these periods or performance measures related to the awards had not yet been met.

10. Inventory

Inventory consists of natural gas and NGLs held in storage for transmission and processing, and also includes materials and supplies. Natural gas inventories related to the Distribution segment in Canada are valued at costs approved by the OEB. The difference between the approved price and the actual cost of gas purchased is recorded in either accounts receivable or other current liabilities for future disposition with customers, subject to approval by the OEB. The remaining inventory is recorded at cost, primarily using average cost.

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The components of inventory are as follows:

	September 30, 2008	December 31, 2007
	(in millions)	
Natural gas	$ 323	$ 154
Natural gas liquids	55	25
Materials and supplies	92	108
Total inventory	$ 470	$ 287

11. Investments in and Loans to Unconsolidated Affiliates

Spectra Energy's most significant investment in unconsolidated affiliates is the 50% investment in DCP Midstream, which is accounted for under the equity method of accounting. The following represents summary financial information for DCP Midstream, presented at 100%.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
	(in millions)			
Operating revenues	$ 4,892	$ 3,115	$ 13,769	$ 9,214
Operating expenses	4,261	2,793	12,370	8,410
Operating income	631	322	1,399	804
Net income	477	281	1,293	690

As further discussed in Note 7, Spectra Energy entered into a propane sales agreement with an affiliate of DCP Midstream in the second quarter of 2008. During the three and nine-month periods ended September 30, 2008, Spectra Energy recorded revenues of $22 million and $36 million, respectively, associated with this agreement, classified within Income (Loss) From Discontinued Operations, Net of Tax.

In the nine-month period ended September 30, 2008, Spectra Energy loaned Southeast Supply Header, LLC (SESH), a 50%-owned equity affiliate, $170 million in connection with the construction of SESH pipeline facilities. The loan receivable from SESH, including accrued interest, totaled $323 million at September 30, 2008 and $148 million at December 31, 2007.

In the nine-month period ended September 30, 2008, Spectra Energy loaned Steckman Ridge, LP (Steckman), a 50%-owned equity affiliate, $21 million in connection with the construction of Steckman storage facilities. The loan receivable from Steckman, including accrued interest, totaled $24 million at September 30, 2008 and $3 million at December 31, 2007.

12. Goodwill

Spectra Energy has completed its annual goodwill impairment test as of August 31, 2008 and no impairments were identified. Spectra Energy primarily uses a discounted cash flow analysis to determine fair value for each reporting unit. Key assumptions in the determination of fair value include the use of an appropriate discount rate and estimated future cash flows. In estimating cash flows, Spectra Energy incorporates expected long-term rates, regulatory stability, the ability to renew contracts, commodity prices (where appropriate), and foreign currency exchange rates, as well as other factors that affect its revenue, expense and capital expenditure projections.

The long-term cash flows and resulting reporting unit values of Spectra Energy's Western Canada gathering and processing operations remain sensitive to projected growth rate assumptions. While exploration and drilling activities slowed somewhat in certain of Spectra Energy's business areas in 2006 and 2007, overall long-term growth rates associated with these Western Canada operations increased during 2008 as a result of strong indicators of

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interest for continued natural gas exploration and drilling in the areas of British Columbia and Alberta that are in close proximity to Spectra Energy's facilities. Management continues to monitor these growth activities.

Management is also monitoring the affects of the economic downturn that could result from the equity market declines that have occurred in recent months. If these conditions continue over the long-term, these factors could increase the long-term cost of capital utilized to calculate reporting unit fair values. Any such increase would primarily affect Spectra Energy's BC Pipeline unit in Western Canada, as well as the Distribution segment. However, if an increase in the cost of capital occurred, the effect on reporting unit fair values would be ultimately offset by a similar increase in these units' regulated revenues since those rates include a component that is based on the units' cost of capital.

13. Debt and Credit Facilities

Spectra Energy completed the following debt issuances during 2008 as part of its overall financing plan to fund capital expenditures and for other corporate purposes.

	Issue Date	Amount (in millions)	Interest Rate	Due Date
Spectra Energy Capital, LLC	April 2008	$ 500	6.20%	2018
Union Gas Limited	April 2008	198(a)	5.35%	2018
Westcoast Energy Inc.	July 2008	250(a)	5.60%	2019
Westcoast Energy Inc.	August 2008	48(a)	5.60%	2019
Union Gas Limited	September 2008	281(a)	6.05%	2038
Spectra Energy Capital, LLC	September 2008	250	5.90%	2013
Spectra Energy Capital, LLC	September 2008	250	7.50%	2038

(a) U.S. dollar equivalent

On July 31, 2008, Maritimes & Northeast Pipeline, L.L.C. paid $288 million to retire its outstanding bonds and bank debt, and an additional $54 million early-extinguishment premium for the bonds. The payment of the premium, a regulatory asset, is presented within Cash Flows from Financing Activities—Other on the Condensed Consolidated Statements of Cash Flows.

Credit Facilities Summary

	Expiration Date	Credit Facilities Capacity	Outstanding at September 30, 2008 Commercial Paper	Term Loan	Revolving Credit (in millions)	Letters of Credit	Total
Spectra Energy Capital, LLC	2012	$ 1,500(a)	$ 128	$ —	$ 654	$ 5	$ 787
Westcoast Energy Inc.	2011	188(b)	—	—	—	—	—
Union Gas Limited	2012	470(c)	131	—	—	—	131
Spectra Energy Partners, LP	2012	500(d)	—	68	172	—	240
Total		$ 2,658	$ 259	$ 68	$ 826	$ 5	$1,158

(a) Credit facility contains a covenant requiring the debt-to-total capitalization ratio to not exceed 65%. Lehman Brothers Commercial Bank (Lehman) is a lender in this facility and, as of September 30, 2008, was in default in its obligation to fund under the agreement. As a result of this default, Spectra Energy Capital, LLC (Spectra Capital) has the right to replace the lender; however, until a replacement is completed, Spectra Capital considers $48 million dollars of unfunded commitment from Lehman to be unavailable. Amounts outstanding under the revolving credit facility are classified within Short-Term Borrowings and Commercial Paper on the Condensed Consolidated Balance Sheets.

(b) Denominated in Canadian dollars totaling 200 million and contains a covenant that requires the debt-to-total capitalization ratio to not exceed 75%.

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(c) Denominated in Canadian dollars totaling 500 million and contains a covenant that requires the debt-to-total capitalization ratio to not exceed 75% and a provision which requires Union Gas to repay all borrowings under the facility for a period of two days during the second quarter of each year.

(d) Contains a covenant requiring the borrower to collateralize the term loan with qualifying investment-grade securities in an amount equal to or greater than the outstanding principal amount of the loan. Lehman is also a lender in this facility. As Lehman Brothers Holding Inc. has filed bankruptcy, Spectra Energy Partners considers $16 million of unfunded commitment from Lehman to be unavailable. Amounts outstanding under the revolving credit facility are classified within Long-Term Debt.

The terms of the Spectra Energy Partners credit facility allow for liquidation of collateral to fund capital expenditures or certain acquisitions provided that an equal amount of term loan is converted to a revolving loan. Investments in marketable securities totaling $69 million at September 30, 2008 and $155 million at December 31, 2007 were pledged as collateral against the term loan. These investments are classified as Investments and Other Assets—Other on the Condensed Consolidated Balance Sheets.

Spectra Energy's debt and credit agreements contain various financial and other covenants. Failure to meet those covenants beyond applicable grace periods could result in accelerated due dates and/or termination of the agreements. As of September 30, 2008, Spectra Energy was in compliance with those covenants. In addition, credit agreements allow for acceleration of payments or termination of the agreements due to nonpayment, or in certain cases, due to the acceleration of other significant indebtedness of the borrower or certain of its subsidiaries. None of the debt or credit agreements contain material adverse change clauses.

14. Common Stock Repurchases

On May 6, 2008, Spectra Energy's Board of Directors authorized a share repurchase program of up to $600 million under which purchases of Spectra Energy common stock under the program were made from time to time in the open market. During the second and third quarters of 2008, Spectra Energy repurchased the cumulative authorized limit of $600 million of common shares, and the share repurchase program was concluded on August 8, 2008. The shares were retired upon repurchase and are presented as a reduction to Additional Paid-In Capital on the Condensed Consolidated Balance Sheets.

15. Fair Value Measurements

Effective January 1, 2008, Spectra Energy adopted the required provisions of SFAS No. 157, "Fair Value Measurements," for financial assets and liabilities. SFAS No. 157 defines fair value, establishes a consistent framework for measuring fair value and expands disclosure requirements about fair value measurements. SFAS No. 157 requires entities to, among other things, maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value.

SFAS No. 157 defines fair value as the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date.

SFAS No. 157 specifies a hierarchy of valuation techniques based on whether the inputs to those valuation techniques are observable or unobservable. Observable inputs reflect market data obtained from independent sources, while unobservable inputs reflect Spectra Energy's market assumptions. In accordance with SFAS No. 157, these two types of inputs have created the following fair value hierarchy:

- Level 1—Quoted unadjusted prices for identical instruments in active markets.
- Level 2—Quoted prices for similar instruments in active markets; quoted prices for identical or similar instruments in markets that are not active; and model-derived valuations in which all significant inputs and significant value drivers are observable in active markets.
- Level 3—Model-derived valuations in which one or more significant inputs or significant value drivers are unobservable.

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The following table presents, for each of the fair value hierarchy levels, Spectra Energy's assets and liabilities that are measured at fair value on a recurring basis as of September 30, 2008.

Description	Balance Sheet Caption	Total	Level 1	Level 2	Level 3
		(in millions)			
Available-for-sale securities	Cash and cash equivalents	$236	$ 99	$ 137	$ —
Short term investment	Current assets-other	5	5	—	—
Available-for-sale securities	Investments and other assets-other	104	34	70	—
Employee benefit assets	Investments and other assets-other	24	24	—	—
Long-term derivative assets	Investments and other assets-other	53	—	11	42
Total Assets		$422	$ 162	$ 218	$ 42
Long-term derivative liabilities	Deferred credits and other liabilities-regulatory and other	15	—	15	—
Total Liabilities		$ 15	$ —	$ 15	$ —

The table below reconciles assets and liabilities measured at fair value on a recurring basis using significant unobservable inputs (Level 3).

	Short-Term Derivative Asset	Short-Term Derivative Liability	Long-Term Derivative Asset	Long-Term Derivative Liability
	(in millions)			
Three Months Ended September 30, 2008				
Fair value, June 30, 2008	$ 108	$ —	$ 79	$ —
Total gains or losses (realized/unrealized):				
Included in earnings	—	—	(7)	2
Included in regulatory assets	(105)	—	—	—
Included in Other Comprehensive Income	—	—	(30)	—
Normal purchases and sales election under SFAS No. 133	—	—	—	(2)
Purchases, issuances and settlements	(3)	—	—	—
Fair value, September 30, 2008	$ —	$ —	$ 42	$ —
Total gains (losses) for the period included in earnings (or changes in net assets) attributable to the change in unrealized gains or losses relating to assets held at September 30, 2008	$ —	$ —	$ (7)	$ 2
Nine Months Ended September 30, 2008				
Fair value, December 31, 2007	$ —	$ —	$ 47	$ (21)
Total gains or losses (realized/unrealized):				
Included in earnings	—	—	4	(11)
Included in regulatory assets	—	—	—	—
Included in Other Comprehensive Income	—	(5)	(9)	—
Normal purchases and sales election under SFAS No. 133	—	—	—	32
Purchases, issuances and settlements	—	5	—	—
Fair value, September 30, 2008	$ —	$ —	$ 42	$ —
Total gains (losses) for the period included in earnings (or changes in net assets) attributable to the change in unrealized gains or losses relating to assets held at September 30, 2008	$ —	$ —	$ 4	$ (11)

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Level 2 Valuation Techniques

Fair values of Spectra Energy's available-for-sale securities, primarily fixed-income debt instruments and money market funds that are actively traded in the secondary market, are determined based on market-based prices. These valuations may include inputs such as quoted market prices of the exact or similar instruments, broker or dealer quotations, or alternative pricing sources that may include models or matrix pricing tools, with reasonable levels of price transparency.

Level 3 Valuation Techniques

Financial instruments are considered Level 3 when their values are determined using pricing models, discounted cash flow methodologies or similar techniques where at least one significant model assumption or input is unobservable. Level 3 financial instruments also include those for which the determination of fair value requires significant management judgment or estimation.

The fair values of Level 3 derivative instruments are estimated using proprietary valuation models that utilize both market observable and unobservable parameters. The long-term derivative asset and liability is valued using internal valuation models and techniques that include such inputs as forward natural gas and power prices, forward interest rates and foreign currency assumptions. The short-term derivative asset is valued based upon interest rates, natural gas options pricing for current and future months including volatility, foreign exchange fluctuations and swap values.

Gains and losses for the three and nine months ended September 30, 2008 associated with the long-term derivative asset and liability are reported in Other Income and Expenses, net on the Condensed Consolidated Statement of Operations and are of offsetting amounts.

During 2008, there were no adjustments to assets and liabilities measured at fair value on a nonrecurring basis.

16. Commitments and Contingencies

Environmental

Spectra Energy is subject to international, federal, state and local regulations regarding air and water quality, hazardous and solid waste disposal and other environmental matters. These regulations can be changed from time to time, imposing new obligations on Spectra Energy.

Remediation activities. Like others in the energy industry, Spectra Energy and its affiliates are responsible for environmental remediation at various contaminated sites. These include some properties that are part of ongoing Spectra Energy operations, sites formerly owned or used by Spectra Energy entities, and sites owned by third parties. Remediation typically involves management of contaminated soils and may involve groundwater remediation. Managed in conjunction with relevant international, federal, state/provincial and local agencies, activities vary with site conditions and locations, remedial requirements, complexity and sharing of responsibility. If remediation activities involve statutory joint and several liability provisions, strict liability, or cost recovery or contribution actions, Spectra Energy or its affiliates could potentially be held responsible for contamination caused by other parties. In some instances, Spectra Energy may share liability associated with contamination with other potentially responsible parties, and may also benefit from insurance policies or contractual indemnities that cover some or all cleanup costs. All of these sites generally are managed in the normal course of business or affiliate operations. Management believes that completion or resolution of these matters will not have a material adverse effect on Spectra Energy's consolidated results of operations, financial position or cash flows.

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Extended Environmental Activities, Accruals. Included in Deferred Credits and Other Liabilities—Regulatory and Other on the Condensed Consolidated Balance Sheets were accruals related to extended environmental-related activities totaling $18 million as of September 30, 2008 and $22 million as of December 31, 2007. These accruals represent provisions for costs associated with remediation activities at some current and former sites, as well as other environmental contingent liabilities. Management believes that completion or resolution of these matters will not have a material adverse effect on Spectra Energy's consolidated results of operations, financial position or cash flows.

Litigation

Duke Energy Retirement Cash Balance Plan. A class action lawsuit was filed in federal court in South Carolina in 2006 against Duke Energy and the Duke Energy Retirement Cash Balance Plan. A second similar class action was also filed in 2006 alleging similar claims and seeking to represent the same class of defendants, but this second case was dismissed without prejudice, and only the first case has moved forward. Various causes of action were alleged in the class action lawsuit, including violations of the Employee Retirement Income Security Act of 1974 (ERISA) and the Age Discrimination in Employment Act. These allegations arise out of the conversion of the Duke Power Company Employees' Retirement Plan into the Duke Power Company Retirement Cash Balance Plan. The plaintiffs seek to represent present and former participants in the Duke Energy Retirement Cash Balance Plan. This group is estimated to include approximately 36,000 persons. Duke Energy filed its answer in March 2006, and various motions were thereafter filed by the parties, including plaintiffs' motion to certify a class, Duke Energy's motion to dismiss, and cross motions for summary judgment filed by both the plaintiffs and Duke Energy. The Court issued a series of rulings in June 2008 denying the plaintiffs class certification motion, dismissing certain of the causes of action originally filed by plaintiffs and allowing other causes of action to proceed. As a result of these rulings, the Plaintiffs re-filed a new Amended Class Action Complaint in June 2008 asserting and re-pleading the claims which the Court is allowing to proceed. Duke Energy filed a motion to dismiss in July 2008 requesting the dismissal of plaintiffs' breach of fiduciary claims. Plaintiffs filed a new motion to certify a class action in August 2008 and Duke Energy has filed a response to this motion. All motions are pending before the Court. A new scheduling order has been entered and it is expected that certain discovery activities will ensue with respect to the surviving causes of action.

In connection with the spin-off from Duke Energy in January 2007, Spectra Energy agreed to share with Duke Energy any liabilities or damages associated with this matter that relate to Spectra Energy employees that may be members of a plaintiff class if one is certified. At mediation, plaintiffs quantified their claims as being in excess of $150 million. However, based on management's current estimate of Spectra Energy employees that could be included in any plaintiff class, management believes that the final disposition of this matter will not have a material adverse effect on Spectra Energy's consolidated results of operations, financial position or cash flows.

Other Litigation and Legal Proceedings. Spectra Energy and its subsidiaries are involved in other legal, tax and regulatory proceedings in various forums arising in the ordinary course of business, including matters regarding contract, royalty, measurement and payment claims, some of which involve substantial monetary amounts. Spectra Energy has insurance coverage for certain of these losses should they be incurred. Management believes that the final disposition of these proceedings will not have a material adverse effect on Spectra Energy's consolidated results of operations, financial position or cash flows.

Spectra Energy has exposure to certain legal matters that are described herein. Spectra Energy had no material reserves as of September 30, 2008 or December 31, 2007 related to litigation matters in accordance with management's best estimate of probable loss as defined by SFAS No. 5, "Accounting for Contingencies."

Legal costs related to the defense of loss contingencies are expensed as incurred.

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Other Commitments and Contingencies

Spectra Energy Islander East Pipeline Company, LLC (Spectra Islander), a wholly owned subsidiary, is a 50% equity partner and operator for the Islander East pipeline project which is owned by Islander East Pipeline Company, L.L.C. (Islander East), a proposed pipeline that would connect natural gas supplies to markets on Long Island, New York. This project has received FERC and other approvals but has been denied a Section 401 Water Quality Certificate (WQC) by the State of Connecticut and was the subject of an appeal before the 2nd Circuit U.S. Court of Appeals (the 2nd Circuit) filed in December 2006. On May 2, 2008, the 2nd Circuit denied Islander East's appeal concerning the State's second WQC denial. Islander East subsequently filed a petition with the 2nd Circuit seeking reconsideration of the court's denial in the WQC case which was denied on June 23, 2008. On September 18, 2008, Islander East filed a petition for certiorari with the U.S. Supreme Court seeking review of the State of Connecticut denial to issue the WQC.

In August 2007, a Connecticut U.S. District Court determined that the Secretary of Commerce's 2004 decision to override the State's denial to issue a Coastal Zone Management Act (CZM) approval was not supported by the record and remanded the matter back to the Secretary of Commerce. Islander East and the U.S. Office of Solicitor General (the Solicitor General) subsequently filed appeals with the 2nd Circuit to overturn the lower court's decision to remand and the State filed a motion to dismiss claiming the U.S. District Court's remand order was non-appealable. In January 2008, the 2nd Circuit granted the State's motion to dismiss. In March 2008, Islander East and the Solicitor General filed separate petitions with the 2nd Circuit seeking reconsideration of the 2nd Circuit's decision in the CZM case. On June 23, 2008, the 2nd Circuit denied the petitions for both the CZM and WQC matters. The Secretary of Commerce has issued a stay in any remand activity due to the pending request for U.S. Supreme Court review of the WQC matter.

Management continues to believe that there are sufficient factual and legal bases supporting Islander East's position that the State's denial of the WQC was in error. Due to the appellate process, management has deferred the project completion date from its previous plans to accommodate the U.S. Supreme Court's review of the petition for a writ of certiorari. However, Islander East remains committed to serving this market area through the development of a future firm transportation project. As of September 30, 2008, Islander East had incurred and capitalized cumulative development costs of $60 million (100% Islander East project level). Algonquin Gas Transmission, LLC (Algonquin), a wholly owned subsidiary, also has a companion project, the AGT Islander East Lease Project. As of September 30, 2008 Algonquin had incurred and capitalized cumulative development costs of $20 million associated with the AGT Islander East Lease Project. Management expects the development and material costs incurred to date could be utilized by other capital projects of Spectra Energy or a deferred project of Islander East, or with respect to materials, sold to third parties.

See Note 17 for a discussion of guarantees and indemnifications.

17. Guarantees and Indemnifications

Spectra Energy and certain of its subsidiaries have various financial guarantees and indemnifications which are issued in the normal course of business. As discussed below, these contracts include financial guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. Spectra Energy and its subsidiaries enter into these arrangements to facilitate a commercial transaction with a third party by enhancing the value of the transaction to the third party. To varying degrees, these guarantees involve elements of performance and credit risk, which are not included on the Condensed Consolidated Balance Sheets. The possibility of Spectra Energy having to honor its contingencies is largely dependent upon future operations of various subsidiaries, investees and other third parties, or the occurrence of certain future events.

Spectra Energy has issued performance guarantees to customers and other third parties that guarantee the payment and performance of other parties, including certain non-wholly owned entities. In connection with the spin-off of Spectra Energy to Duke Energy shareholders, certain guarantees that were previously issued by Spectra Energy were assigned to, or replaced by, Duke Energy as guarantor in 2006. For any remaining guarantees of other Duke Energy obligations, Duke Energy has indemnified Spectra Energy against any losses incurred under these guarantee arrangements.

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The maximum potential amount of future payments Spectra Energy could have been required to make under these performance guarantees as of September 30, 2008 was approximately $460 million, which has been indemnified by Duke Energy, as discussed above. Approximately $33 million of the performance guarantees will expire during the remainder of 2008 through 2010, with the remaining performance guarantees expiring after 2010 or having no contractual expiration.

Additionally, Spectra Energy has issued joint and several guarantees to some of the Duke/Fluor Daniel (D/FD) project owners, guaranteeing the performance of D/FD under its engineering, procurement and construction contracts and other contractual commitments. D/FD is one of the entities transferred to Duke Energy in connection with the spin-off of Spectra Energy from Duke Energy. Substantially all of these guarantees have no contractual expiration and no stated maximum amount of future payments that Spectra Energy could be required to make. Fluor Enterprises Inc., as 50% owner in D/FD, has issued similar joint and several guarantees to the same D/FD project owners. In accordance with the D/FD partnership agreement, each of the partners is responsible for 50% of any payments to be made under those guarantees.

Westcoast has issued performance guarantees to third parties guaranteeing the performance of unconsolidated entities, such as equity method investments, and of entities previously sold by Westcoast to third parties. Those guarantees require Westcoast to make payment to the guaranteed third party upon the failure of such unconsolidated or sold entity to make payment under some of its contractual obligations, such as debt, purchase contracts and leases. Certain guarantees that were previously issued by Westcoast for obligations of entities that remained a part of Duke Energy are considered guarantees of third-party performance; however, Duke Energy has indemnified Spectra Energy against any losses incurred under these guarantee arrangements.

The maximum potential amount of future payments Westcoast could have been required to make under those performance guarantees of non-wholly owned entities and third-party entities as of September 30, 2008 was $56 million. Guarantees related to Westcoast have no contractual expiration.

Spectra Energy has entered into various indemnification agreements related to purchase and sale agreements and other types of contractual agreements with vendors and other third parties. These agreements typically cover environmental, tax, litigation and other matters, as well as breaches of representations, warranties and covenants. Typically, claims may be made by third parties for various periods of time, depending on the nature of the claim. Spectra Energy's potential exposure under these indemnification agreements can range from a specified amount, such as the purchase price, to an unlimited dollar amount, depending on the nature of the claim and the particular transaction. Spectra Energy is unable to estimate the total potential amount of future payments under these indemnification agreements due to several factors, such as the unlimited exposure under certain guarantees.

At September 30, 2008, the amounts recorded for the guarantees and indemnifications described above, including the indemnifications by Duke Energy to Spectra Energy, are not material, both individually and in the aggregate.

18. Employee Benefit Plans

Retirement Plans. Effective with the separation from Duke Energy on January 2, 2007, Spectra Energy established a new qualified non-contributory defined benefit (DB) retirement plan for U.S. employees and new non-qualified plans for various executive retirement and savings plans. Spectra Energy's Westcoast subsidiary maintains retirement plans that cover substantially all employees of Spectra Energy's Canadian operations. In accordance with the separation agreement with Duke Energy, $49 million of net qualified pension plan assets and $52 million in liabilities associated with various executive retirement and savings plans were transferred to Spectra Energy in 2007.

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Spectra Energy's policy is to fund amounts for U.S. qualified retirement plans on an actuarial basis to provide assets sufficient to meet benefits to be paid to plan participants. Spectra Energy did not make contributions to its U.S. retirement plans in the nine-month periods ended September 30, 2008 and 2007, and does not anticipate making any contributions to the U.S. plans during the remainder of 2008.

Spectra Energy's policy is to fund its DB retirement plans in Canada on an actuarial basis and in accordance with Canadian pension standards legislation in order to accumulate assets sufficient to meet benefit obligations. Contributions to the defined contribution (DC) retirement plan are determined in accordance with the terms of the plan. Spectra Energy made contributions to the Canadian qualified DB plans of $28 million and $31 million during the nine-month periods ended September 30, 2008 and 2007, respectively. Spectra Energy anticipates that it will make additional contributions of approximately $15 million to the Canadian DB plans during the remainder of 2008, for a total of $43 million of contributions in 2008. Spectra Energy also made contributions to the Canadian DC plan of $4 million and $3 million during the nine-month periods ended September 30, 2008 and 2007, respectively. Spectra Energy anticipates that it will make additional contributions of approximately $1 million to the Canadian DC plans during the remainder of 2008, for a total of $5 million of contributions in 2008.

Qualified Pension Plans—Components of Net Periodic Pension Costs

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
	(in millions)			
U.S.				
Service cost benefit earned	$ 2	$ 3	$ 7	$ 8
Interest cost on projected benefit obligation	6	6	20	19
Expected return on plan assets	(9)	(10)	(27)	(28)
Amortization of loss	1	1	2	4
Amortization of prior service cost	—	1	—	1
Net periodic pension cost	$ —	$ 1	$ 2	$ 4
Canada				
Service cost benefit earned	$ 4	$ 4	$ 12	$ 11
Interest cost on projected benefit obligation	10	9	30	26
Expected return on plan assets	(12)	(11)	(36)	(31)
Amortization of loss	1	1	4	5
Amortization of prior service cost	—	1	—	1
Net periodic pension cost	$ 3	$ 4	$ 10	$ 12

Non-Qualified Pension Benefits Plans—Components of Net Periodic Pension Costs

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
	(in millions)			
U.S.				
Interest cost on projected benefit obligation	$ —	$ —	$ 1	$ 1
Net periodic pension cost	$ —	$ —	$ 1	$ 1
Canada				
Service cost benefit earned	$ —	$ 1	$ 1	$ 1
Interest cost on projected benefit obligation	1	1	4	3
Amortization of loss	—	—	—	1
Net periodic pension cost	$ 1	$ 2	$ 5	$ 5

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Other Post-Retirement Benefit Plans. Spectra Energy and most of its subsidiaries provide certain health care and life insurance benefits for retired employees on a contributory and non-contributory basis. In accordance with the separation agreement, $194 million in liabilities associated with other post-retirement benefits were transferred to Spectra Energy upon the separation from Duke Energy.

Other Post-Retirement Benefit Plans—Components of Net Periodic Costs

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
	(in millions)			
U.S.				
Interest cost on accumulated post-retirement benefit obligation	$ 4	$ 4	$ 11	$ 12
Expected return on plan assets	(1)	(2)	(4)	(4)
Amortization of net transition liability	1	2	4	4
Amortization of prior service credit	—	—	—	(1)
Amortization of loss	—	—	1	2
Net periodic other post-retirement benefit cost	$ 4	$ 4	$ 12	$ 13
Canada				
Service cost benefit earned	$ 1	$ 1	$ 2	$ 2
Interest cost on accumulated post-retirement benefit obligation	1	2	4	4
Amortization of prior service credit	—	(1)	—	(1)
Net periodic other post-retirement benefit cost	$ 2	$ 2	$ 6	$ 5

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19. Consolidating Financial Information

Spectra Energy Corp has fully and unconditionally guaranteed the payment of principal and interest under all series of notes outstanding under the Senior Indenture of Spectra Energy Capital, LLC (Spectra Capital), the wholly owned, consolidated subsidiary of Spectra Energy Corp. In accordance with Securities and Exchange Commission (SEC) rules, the following condensed consolidating financial information is presented. The information shown for Spectra Energy Corp and Spectra Capital is presented utilizing the equity method of accounting for investments in subsidiaries, as required. The non-guarantor subsidiaries column represents all wholly owned subsidiaries of Spectra Capital. This information should be read in conjunction with Spectra Energy's accompanying condensed consolidated financial statements and notes thereto.

Spectra Energy Corp
Condensed Consolidating Statement of Operations
Three Months Ended September 30, 2008
(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Spectra Energy Corp Consolidated
Total operating revenues	$ —	$ —	$ 1,080	$ —	$ 1,080
Total operating expenses	(9)	—	749	—	740
Operating income	9	—	331	—	340
Equity in earnings of unconsolidated affiliates	—	—	273	—	273
Equity in earnings of subsidiaries	288	440	—	(728)	—
Other income and expenses, net	3	5	1	—	9
Interest expense	—	63	100	—	163
Minority interest expense	—	—	15	—	15
Earnings from continuing operations before income taxes	300	382	490	(728)	444
Income tax expense from continuing operations	4	94	47	—	145
Loss from discontinued operations, net of tax	—	—	(3)		(3)
Net income	$ 296	$ 288	$ 440	$ (728)	$ 296

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Spectra Energy Corp
Condensed Consolidating Statement of Operations
Three Months Ended September 30, 2007
(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Spectra Energy Corp Consolidated
Total operating revenues	$ —	$ —	$ 950	$ —	$ 950
Total operating expenses	9	—	616	—	625
Gains on sales of other assets, net	—	—	5	—	5
Operating income (loss)	(9)	—	339	—	330
Equity in earnings of unconsolidated affiliates	—	—	175	—	175
Equity in earnings of subsidiaries	240	585	—	(825)	—
Other income and expenses, net	1	—	10	—	11
Interest expense	—	58	98	—	156
Minority interest expense	—	—	15	—	15
Earnings from continuing operations before income taxes	232	527	411	(825)	345
Income tax expense (benefit) from continuing operations	(2)	287	(175)	—	110
Income from discontinued operations, net of tax	—	—	3	—	3
Extraordinary item, net of tax	—	—	(4)	—	(4)
Net income	$ 234	$ 240	$ 585	$ (825)	$ 234

Spectra Energy Corp
Condensed Consolidating Statement of Operations
Nine Months Ended September 30, 2008
(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Spectra Energy Corp Consolidated
Total operating revenues	$ —	$ —	$ 3,813	$ —	$ 3,813
Total operating expenses	1	1	2,667	—	2,669
Gains on sales of other assets and other, net	—	—	32	—	32
Operating income (loss)	(1)	(1)	1,178	—	1,176
Equity in earnings of unconsolidated affiliates	—	—	725	—	725
Equity in earnings of subsidiaries	958	1,467	—	(2,425)	—
Other income and expenses, net	1	11	18	—	30
Interest expense	—	172	298	—	470
Minority interest expense	—	—	46	—	46
Earnings from continuing operations before income taxes	958	1,305	1,577	(2,425)	1,415
Income tax expense from continuing operations	—	347	106	—	453
Loss from discontinued operations, net of tax	—	—	(4)	—	(4)
Net income	$ 958	$ 958	$ 1,467	$ (2,425)	$ 958

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Spectra Energy Corp
Condensed Consolidating Statement of Operations
Nine Months Ended September 30, 2007
(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Spectra Energy Corp Consolidated
Total operating revenues	$ —	$ —	$ 3,317	$ —	$ 3,317
Total operating expenses	27	1	2,253	—	2,281
Gains on sales of other assets and other, net	—	—	6	—	6
Operating income (loss)	(27)	(1)	1,070	—	1,042
Equity in earnings of unconsolidated affiliates	—	—	394	—	394
Equity in earnings of subsidiaries	683	1,102	—	(1,785)	—
Other income and expenses, net	1	(1)	37	—	37
Interest expense	—	161	306	—	467
Minority interest expense	—	—	41	—	41
Earnings from continuing operations before income taxes	657	939	1,154	(1,785)	965
Income tax expense (benefit) from continuing operations	(9)	256	65	—	312
Income from discontinued operations, net of tax	—	—	17	—	17
Extraordinary item, net of tax	—	—	(4)	—	(4)
Net income	$ 666	$ 683	$ 1,102	$ (1,785)	$ 666

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Spectra Energy Corp
Condensed Consolidating Balance Sheet
September 30, 2008
(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Spectra Energy Corp Consolidated
Cash and cash equivalents	$ —	$ 99	$ 182	$ —	$ 281
Receivables (payables)—consolidated subsidiaries	(50)	285	(230)	(5)	—
Receivables—other	1	6	788	—	795
Other current assets	13	14	715	—	742
Total current assets	(36)	404	1,455	(5)	1,818
Investments in and loans to unconsolidated affiliates	—	—	2,089	—	2,089
Investments in consolidated subsidiaries	7,998	11,330	—	(19,328)	—
Advances receivable (payable)—consolidated subsidiaries	(1,752)	3,079	(1,327)	—	—
Goodwill	—	—	3,767	—	3,767
Other assets	97	365	54	—	516
Property, plant and equipment, net	—	—	14,361	—	14,361
Regulatory assets and deferred debits	—	16	940	—	956
Total Assets	$ 6,307	$15,194	$ 21,339	$ (19,333)	$ 23,507
Accounts payable (receivable)—consolidated subsidiaries	$ 5	$ 42	$ (42)	$ (5)	$ —
Accounts payable—other	1	126	222	—	349
Accrued taxes payable (receivable)	(311)	385	71	—	145
Current maturities of long-term debt	—	147	74	—	221
Other current liabilities	14	1,224	602	—	1,840
Total current liabilities	(291)	1,924	927	(5)	2,555
Long-term debt	—	3,450	5,919	—	9,369
Deferred credits and other liabilities	177	1,822	2,462	—	4,461
Minority interests	—	—	701	—	701
Total stockholders' equity	6,421	7,998	11,330	(19,328)	6,421
Total Liabilities and Stockholders' Equity	$ 6,307	$15,194	$ 21,339	$ (19,333)	$ 23,507

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Spectra Energy Corp
Condensed Consolidating Balance Sheet
December 31, 2007
(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Spectra Energy Corp Consolidated
Cash and cash equivalents	$ —	$ —	$ 94	$ —	$ 94
Receivables (payables)–consolidated subsidiaries	(9)	269	(255)	(5)	—
Receivables—other	2	8	897	—	907
Other current assets	8	1	369	—	378
Total current assets	1	278	1,105	(5)	1,379
Investments in and loans to unconsolidated affiliates	—	3	1,777	—	1,780
Investments in consolidated subsidiaries	7,434	10,281	—	(17,715)	—
Advances receivable (payable)—consolidated subsidiaries	(752)	2,369	(1,617)	—	—
Goodwill	—	—	3,948	—	3,948
Other assets	100	210	321	—	631
Property, plant and equipment, net	—	2	14,298	—	14,300
Regulatory assets and deferred debits	5	7	920	—	932
Total Assets	$6,788	$13,150	$ 20,752	$ (17,720)	$ 22,970
Accounts payable (receivable)—consolidated subsidiaries	$ 5	$ 42	$ (42)	$ (5)	$ —
Accounts payable—other	7	107	249	—	363
Accrued taxes payable (receivable)	(278)	233	130	—	85
Current maturities of long-term debt	—	—	338	—	338
Other current liabilities	26	544	1,066	—	1,636
Total current liabilities	(240)	926	1,741	(5)	2,422
Long-term debt	—	2,975	5,370	—	8,345
Deferred credits and other liabilities	171	1,815	2,554	—	4,540
Minority interests	—	—	806	—	806
Total stockholders' equity	6,857	7,434	10,281	(17,715)	6,857
Total Liabilities and Stockholders' Equity	$6,788	$13,150	$ 20,752	$ (17,720)	$ 22,970

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Spectra Energy Corp
Condensed Consolidating Statement of Cash Flows
Nine Months Ended September 30, 2008
(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Spectra Energy Corp Consolidated
Net cash provided by (used in) operating activities	$ (5)	$ (327)	$ 1,728	$ —	$ 1,396
Net cash used in investing activities	—	(190)	(1,374)	—	(1,564)
Net cash provided by (used in) financing activities	5	616	(267)	—	354
Effect of exchange rate changes on cash	—	—	1	—	1
Net increase in cash and cash equivalents	—	99	88	—	187
Cash and cash equivalents at beginning of period	—	—	94	—	94
Cash and cash equivalents at end of period	$ —	$ 99	$ 182	$ —	$ 281

Spectra Energy Corp
Condensed Consolidating Statement of Cash Flows
Nine Months Ended September 30, 2007
(In millions)

	Spectra Energy Corp	Spectra Capital	Non-Guarantor Subsidiaries	Eliminations	Spectra Energy Corp Consolidated
Net cash provided by (used in) operating activities	$ (170)	$ (100)	$ 1,122	$ —	$ 852
Net cash used in investing activities	—	(51)	(1,066)	—	(1,117)
Net cash provided by (used in) financing activities	170	195	(326)	—	39
Effect of exchange rate changes on cash	—	—	62	—	62
Net increase (decrease) in cash and cash equivalents	—	44	(208)	—	(164)
Cash and cash equivalents at beginning of period	—	(44)	343	—	299
Cash and cash equivalents at end of period	$ —	$ —	$ 135	$ —	$ 135

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20. New Accounting Pronouncements

The following new accounting pronouncements were adopted during the nine months ended September 30, 2008:

SFAS No. 157, "Fair Value Measurements." In September 2006, the Financial Accounting Standards Board (FASB) issued SFAS No. 157, which defines fair value, establishes a framework for measuring fair value in GAAP and expands disclosures about fair value measurements. In February 2008, the FASB issued FASB Staff Position (FSP) No. FAS 157-1, "Application of FASB Statement No. 157 to FASB Statement No. 13 and Other Accounting Pronouncements That Address Fair Value Measurements for Purposes of Lease Classification or Measurement under Statement 13." Also in February 2008, the FASB issued FSP No. 157-2, "Effective Date of FASB Statement No. 157," which delays the effective date of SFAS No. 157 to fiscal years beginning after November 15, 2008 for nonfinancial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). The adoption of SFAS No. 157 and FSP No. FAS 157-1 by Spectra Energy effective January 1, 2008 did not have a material impact on Spectra Energy's consolidated results of operations, financial position or cash flows. See Note 15 for further discussion. Spectra Energy has elected to defer the adoption of SFAS No. 157 for its goodwill impairment test and the measurement of asset retirement obligations until January 1, 2009 as permitted.

In October 2008, the FASB issued FSP No. FAS 157-3, *"Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active,"* which clarifies the application of SFAS No. 157 in determining the fair value of a financial asset when the market for that financial asset is not active. FSP No. FAS 157-3 was effective upon issuance, including prior periods for which financial statements have not been issued. Revisions in fair values resulting from a change in the valuation technique or its application would be accounted for as a change in accounting estimate. The adoption of FSP No. FAS 157-3 had no impact on Spectra Energy's consolidated results of operations, financial position or cash flows.

SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities." In February 2007, the FASB issued SFAS No. 159, which permits entities to choose to measure certain financial instruments at fair value. Spectra Energy has determined it will not elect fair value measurements for financial assets and financial liabilities included in the scope of SFAS No. 159.

EITF 06-11, "Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards." In June 2007, the FASB Emerging Issues Task Force (EITF) reached a consensus that a realized income tax benefit from dividends or dividend equivalents that are charged to retained earnings and are paid to employees for equity classified nonvested equity shares, nonvested equity share units, and outstanding equity share options should be recognized as an increase to additional paid-in capital. The amount recognized in additional paid-in capital for the realized income tax benefit from dividends on those awards should be included in the pool of excess tax benefits available to absorb tax deficiencies on share-based payment awards. EITF 06-11 was applied to the income tax benefits that result from dividends on equity-classified employee share-based payment awards that are declared after December 31, 2007. The effect of adopting EITF 06-11 was not material to Spectra Energy's consolidated results of operations, financial position or cash flows as of and for the nine-month period ended September 30, 2008 and is not expected to be material to future periods.

The following new accounting pronouncements have been issued, but have not yet been adopted as of September 30, 2008:

SFAS No. 141R, "Business Combinations." In December 2007, the FASB issued SFAS No. 141R which replaces SFAS No. 141, "Business Combinations." SFAS No. 141R requires the acquiring entity in a business combination to recognize all and only the assets acquired and liabilities assumed in the transaction, establishes the acquisition-date fair value as the measurement objective for all assets acquired and liabilities assumed, and requires the acquirer to disclose to investors and other users all of the information they need to evaluate and understand the nature and financial effect of the business combination. SFAS No. 141R applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008 and cannot be early adopted.

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SFAS No. 160, "Noncontrolling Interest in Consolidated Financial Statements." In December 2007, the FASB issued SFAS No. 160 which requires all entities to report noncontrolling (minority) interests in subsidiaries as equity in the consolidated financial statements. SFAS No. 160 eliminates the diversity that currently exists in accounting for transactions between an entity and noncontrolling interests by requiring they be treated as equity transactions. SFAS No. 160 is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. Early adoption is prohibited.

When adopting the presentation and disclosure items, retrospective application to conform previously reported financial statements to the new presentation requirements is required. Changes to reflect the new measurement guidance for increases or decreases in ownership and other changes must be done prospectively. The new requirements for noncontrolling interests, results of operations and comprehensive income of subsidiaries change the presentation of operating results, related per-share information, and equity. SFAS No. 160 requires net income and comprehensive income to be displayed for both the controlling and the noncontrolling interests. Additional required disclosures and reconciliations include a separate schedule that shows the effects of any transactions with the noncontrolling interests on the equity attributable to the controlling interest.

Spectra Energy continues to examine the balances previously reflected as minority interests on the Condensed Consolidated Balance Sheet and of the amount of minority interest net income previously reflected within net income. Spectra Energy cannot currently estimate the full effect that this standard will have on its historical or future consolidated results of operations, financial position and cash flows. However, previously deferred gains associated with the formation of Spectra Energy Partners totaling approximately $60 million, currently classified within Deferred Credits and Other Liabilities—Regulatory and Other on the Condensed Consolidated Balance Sheets at September 30, 2008 and December 31, 2007, is expected to be reclassified to Stockholders' Equity upon adoption of this standard.

SFAS No. 161 "Disclosures about Derivative Instruments and Hedging Activities—an amendment of FASB Statement No. 133." In March 2008, the FASB issued SFAS No. 161 which amends and expands the disclosure requirements for SFAS No. 133 with the intent to provide users of financial statements an enhanced understanding of how and why derivative instruments are used, how derivative instruments and related hedged items are accounted for under SFAS No. 133 and its related interpretations and how derivative instruments and related hedged items affect an entity's financial position, financial performance, and cash flows. SFAS No. 161 is effective for fiscal years and interim periods within those fiscal years, beginning on or after November 15, 2008.

FSP No. FAS 142-3, "Determination of the Useful Life of Intangible Assets." In April 2008, the FASB issued FSP No. FAS 142-3 which amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset under SFAS No. 142, "Goodwill and Other Intangible Assets." FSP No. FAS 142-3 is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. Spectra Energy does not expect the adoption of FSP No. FAS 142-3 to have a material impact on its consolidated results of operations, financial position or cash flows.

21. Subsequent Events

On October 7, 2008, Spectra Energy entered into an agreement to sell certain interests in the natural gas gathering and processing facilities within the Western Canada Transmission & Processing segment. See Note 7 for further discussion.

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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations.

INTRODUCTION

Management's Discussion and Analysis of Financial Condition and Results of Operations should be read in conjunction with the Condensed Consolidated Financial Statements. As previously discussed, the Condensed Consolidated Statements of Operations and related discussions contained in this report have been re-cast to reflect the operating results of certain Western Canada Transmission & Processing natural gas gathering and processing facilities as discontinued operations for all periods presented. See Note 7 of Notes to Condensed Consolidated Financial Statements for further discussion.

Executive Overview

For the three months ended September 30, 2008 and 2007, Spectra Energy reported net income of $296 million and $234 million, respectively. For the nine months ended September 30, 2008 and 2007, Spectra Energy reported net income of $958 million and $666 million, respectively. The increase in net income for the three and nine-month periods primarily reflects the positive impact of higher NGL prices, which correlate to higher crude oil prices, during the first nine months of 2008 on the earnings from Field Services. Crude oil averaged $113 per barrel for the nine months ended September 30, 2008 versus $67 per barrel during the same period in 2007.

The highlights for the three months and nine months ended September 30, 2008 include:

- U.S. Transmission's earnings benefited from completed expansion projects and a customer bankruptcy settlement in the second quarter of 2008, offset by higher project development costs charged to expense, primarily in the third quarter 2008, as well as higher operating and administrative costs.
- Distribution results reflect higher storage and transportation revenues and a stronger Canadian dollar comparing the 2008 and 2007 periods.
- Western Canada Transmission & Processing earnings increased primarily as a result of higher volumes and stronger NGL prices related to the Empress processing plant and a stronger Canadian dollar.
- Field Services earnings reflect higher NGL prices, improved efficiencies and higher volumes, partially offset by lost revenues in the third quarter 2008 resulting from Hurricane Ike.
- Results for Other include costs associated with the spin-off of Spectra Energy in 2007, mostly offset by the favorable resolution of a legal matter in 2007 and higher benefits and incentive costs in 2008.

Spectra Energy reported $1.5 billion of capital and investment expenditures in the first nine months of 2008 of the approximately $2.2 billion that is projected for the full year, including expansion capital of approximately $1.6 billion. As of early November 2008, Spectra Energy's 2008 expansion projects are substantially complete, with returns on these projects expected to be at the high end of those originally anticipated. Expansion expenditures for 2009 are currently expected to be about one-half of the amount of 2008, mainly as a result of many of the larger projects coming into service in 2008 or early 2009. Spectra Energy continues to assess projected long-term market requirements and, based on the current assessment, believes that expansion expenditures will continue to support strategic objectives.

Through September 30, 2008, Spectra Energy has successfully issued approximately $1.8 billion of new long-term debt, completing the new long-term debt issuances expected for 2008. In addition, Spectra Energy continues to have ongoing access to over $2.5 billion in credit facilities and has continued to utilize commercial paper and revolving lines of credit as needed to fund liquidity needs throughout September and October 2008 when there has been significant general market disruption around credit.

On May 6, 2008, Spectra Energy's Board of Directors approved a share repurchase program, authorizing Spectra Energy to purchase in the aggregate up to $600 million of shares of its outstanding common stock. This share repurchase program was completed on August 8, 2008.

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On July 3, 2008, Spectra Energy declared a 9% increase in its quarterly dividend from $0.23 to $0.25 per common share. The new annualized dividend rate is $1.00 per share, representing a nearly 14% increase over the 2007 level of $0.88 per share.

RESULTS OF OPERATIONS

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
	(in millions)			
Operating revenues	$ 1,080	$ 950	$ 3,813	$ 3,317
Operating expenses	740	625	2,669	2,281
Gains on sales of other assets and other, net	—	5	32	6
Operating income	340	330	1,176	1,042
Other income and expenses, net	282	186	755	431
Interest expense	163	156	470	467
Minority interest expense	15	15	46	41
Earnings from continuing operations before income taxes	444	345	1,415	965
Income tax expense from continuing operations	145	110	453	312
Income from continuing operations	299	235	962	653
Income (loss) from discontinued operations, net of tax	(3)	3	(4)	17
Income before extraordinary items	296	238	958	670
Extraordinary items, net of tax	—	(4)	—	(4)
Net income	$ 296	$ 234	$ 958	$ 666

Three and Nine Months Ended September 30, 2008 Compared to Same Periods in 2007

Operating Revenues. Operating revenues for the three and nine months ended September 30, 2008 increased $130 million or 14%, and $496 million or 15%, respectively, compared to the same periods in 2007. The increases were driven primarily by:

- higher NGL prices associated with the Empress operations,
- the effects of a stronger Canadian dollar on revenues at Western Canada Transmission & Processing and Distribution, and
- expansion projects placed in service in late 2007 at U.S. Transmission.

Operating Expenses. Operating expenses for the three and nine months ended September 30, 2008 increased $115 million or 18%, and $388 million or 17%, respectively, compared to the same periods in 2007. The increases were driven primarily by:

- higher prices and volumes of natural gas purchased for the Empress facility,
- the effects of a stronger Canadian dollar at Western Canada Transmission & Processing and Distribution,
- an increase in project development costs as a result of the capitalization of previously expensed costs on northeast expansions in 2007, and increased operating and administrative costs at U.S. Transmission.

For a more detailed discussion of operating revenues and expenses, see the segment discussions that follow.

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Gains on Sales of Other Assets and Other, net. Gains on sales of other assets and other, net for the three and nine months ended September 30, 2008 decreased $5 million and increased $26 million, respectively, compared to the same periods in 2007. The increase year-to-date, was primarily due to a 2008 second quarter customer bankruptcy settlement.

Operating Income. Operating income for the three and nine months ended September 30, 2008 increased $10 million, or 3%, and $134 million, or 13%, respectively, compared to the same periods in 2007 primarily as a result of higher NGL prices that benefited the Empress operations, a stronger Canadian dollar, a 2008 customer bankruptcy settlement, and higher earnings from expansion projects, partially offset by higher project development costs charged to expense as well as higher operating and administrative costs.

Other Income and Expenses, net. Other income and expenses, net for the three and nine months ended September 30, 2008 increased $96 million and $324 million, respectively, compared to the same periods in 2007. The increases represent higher equity in earnings from the Field Services segment, primarily reflecting higher commodity prices in 2008 compared to 2007.

Interest Expense. Interest expense for the three and nine months ended September 30, 2008 increased $7 million and $3 million, respectively, compared to the same periods in 2007, reflecting the successful completion of Spectra Energy's planned debt issuances in 2008 and a stronger Canadian dollar, partially offset by lower balances and rates on commercial paper, higher interest costs capitalized and increased benefits from interest rate swaps in 2008.

Minority Interest Expense. Minority interest expense for the nine months ended September 30, 2008 increased $5 million compared to the same period in 2007, primarily as a result of earnings from Spectra Energy Partners formed in July 2007.

Income Tax Expense from Continuing Operations. Income tax expense from continuing operations for the three and nine months ended September 30, 2008 increased $35 million and $141 million, respectively, as a result of higher earnings from continuing operations. The effective tax rate for income from continuing operations for the three months ended September 30, 2008 was 32.7% as compared to 31.9% for the same period in 2007. The lower effective tax rate in the prior period was primarily a result of an adjustment in the 2007 period for final 2006 tax returns in Canada. The effective tax rate for the nine months ended September 30, 2008 was 32.0% as compared to 32.3% for the same period of 2007.

Income (Loss) from Discontinued Operations, net of tax. Income from discontinued operations for the three and nine months ended September 30, 2008 decreased $6 million and $21 million, respectively. The year-to-date variance is driven by proceeds received from a litigation settlement in the second quarter of 2007. The decreases for three months and nine months ended September 30, 2008 also reflect the operating results of certain Western Canada Transmission & Processing natural gas gathering and processing facilities. In October 2008, Spectra Energy entered into an agreement to sell its interests in these facilities.

Extraordinary Items, net of tax. Extraordinary items, net of tax for the three and nine months ended September 30, 2007 reflected an extraordinary loss in the third quarter of 2007 of $4 million, net of tax. Union Gas received a decision from the OEB in 2006 that effectively caused a portion of its storage operations to become unregulated. As a result of an additional and related August 2007 decision from the OEB, Spectra Energy recorded an extraordinary loss to further remove the effects of storage regulation from the consolidated balance sheet.

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Segment Results

Management evaluates segment performance based on EBIT from continuing operations, after deducting minority interest expense related to those earnings. On a segment basis, EBIT excludes discontinued operations, represents all profits from continuing operations (both operating and non-operating) before deducting interest and taxes, and is net of the minority interest expense related to those profits. Cash, cash equivalents and short-term investments are managed centrally by Spectra Energy, so the gains and losses on foreign currency transactions, and interest and dividend income on those balances, are excluded from the segments' EBIT. Management considers segment EBIT to be a good indicator of each segment's operating performance from its continuing operations, as it represents the results of Spectra Energy's ownership interest in operations without regard to financing methods or capital structures.

Spectra Energy's segment EBIT may not be comparable to similarly titled measures of other companies because other companies may not calculate EBIT in the same manner. Segment EBIT is summarized in the following table, and detailed discussions follow.

EBIT by Business Segment

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
	(in millions)			
U.S. Transmission	$ 213	$ 230	$ 683	$ 673
Distribution	44	40	263	238
Western Canada Transmission & Processing	113	101	333	218
Field Services	239	140	647	345
Total reportable segment EBIT	609	511	1,926	1,474
Other	(9)	(15)	(57)	(56)
Total reportable segment and other EBIT	600	496	1,869	1,418
Interest expense	163	156	470	467
Interest income and other (a)	7	5	16	14
Consolidated earnings from continuing operations before income taxes	$ 444	$ 345	$ 1,415	$ 965

(a) Includes foreign currency transaction gains and losses, additional minority interest expense not allocated to the segment results and intersegment eliminations.

Minority interest expense as presented in the following segment-level discussions includes only minority interest expense related to EBIT of non-wholly owned entities. It does not include minority interest expense related to interest and taxes of those operations. The amounts discussed below include intercompany transactions that are eliminated in the Condensed Consolidated Financial Statements.

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U.S. Transmission

	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Increase (Decrease)	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007	Increase (Decrease)
	(in millions, except where noted)					
Operating revenues	$402	$386	$ 16	$1,205	$1,133	$ 72
Operating expenses						
Operating, maintenance and other	156	126	30	433	328	105
Depreciation and amortization	58	57	1	174	162	12
Gains on sales of other assets and other, net	—	—	—	32	1	31
Operating income	188	203	(15)	630	644	(14)
Other income and expenses, net	39	41	(2)	94	63	31
Minority interest expense	14	14	—	41	34	7
EBIT	$213	$230	$ (17)	$ 683	$ 673	$ 10
Proportional throughput, Tbtu (a)	479	531	(52)	1,596	1,641	(45)

(a) Trillion British thermal units. Revenues are not significantly affected by pipeline throughput fluctuations, since revenues are primarily composed of demand charges.

Three Months Ended September 30, 2008 Compared to Same Period in 2007

Operating Revenues. The $16 million increase was driven primarily by:

- a $16 million increase from expansion projects placed in service in late 2007 and third quarter 2008, and
- a $6 million increase in processing revenues associated with pipeline operations, primarily from higher NGL prices.

Operating, Maintenance and Other. The $30 million increase was driven primarily by:

- a $19 million increase in operating and administrative costs including fuel, utilities, equipment repairs, benefit and software costs, and
- an $8 million increase in project development costs expensed when comparing the periods. In accordance with Spectra Energy's policy, project development costs are initially expensed until it is determined that recovery of such costs through regulated revenues of the completed project is probable, at which time inception-to-date costs of the project are capitalized and operating expenses are reduced.

Other Income and Expenses, net. The $2 million decrease was primarily a result of lower equity income attributable to the net capitalization of project development costs in 2007 on SESH and Gulfstream's Phase IV expansion projects totaling $18 million, mostly offset by the increased capitalization of interest associated with the SESH project.

EBIT. The $17 million decrease reflects higher project development expenses, primarily resulting from the capitalization of these expenses in the prior quarter, and increased operating and administrative costs, partially offset by higher earnings from expansion projects placed in service in late 2007 and higher earnings from capitalized interest on construction projects during the 2008 quarter.

Nine Months Ended September 30, 2008 Compared to Same Period in 2007

Operating Revenues. The $72 million increase was driven primarily by:

- a $46 million increase from expansion projects placed in service in late 2007 and third quarter 2008,

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- a $23 million increase in processing revenues associated with pipeline operations, primarily from higher NGL prices, and
- a $9 million increase resulting from a stronger Canadian dollar, related to M&N LP.

Operating, Maintenance and Other. The $105 million increase was driven primarily by:

- a $50 million increase in project development costs, reflecting expensed project development costs of $28 million in 2008 and a net benefit of $22 million in 2007 due to the capitalization of previously expensed costs on northeast expansions during that period,
- a $35 million increase in operating and administrative costs including pipeline integrity, fuel, utilities, equipment repairs, labor and outside services and software costs, and
- a $16 million increase in ad valorem taxes primarily as a result of favorable valuations in 2007.

Depreciation and Amortization. The $12 million increase was driven primarily by expansion projects placed into service in 2007.

Gains on Sales of Other Assets and Other, net. The $31 million increase reflects a customer bankruptcy settlement in June 2008.

Other Income and Expenses, net. The $31 million increase was primarily a result of higher equity income from unconsolidated affiliates attributable to the capitalization of interest on construction projects and $7 million of lower project development costs charged to expense, both of which are primarily for the SESH project.

Minority Interest Expense. The $7 million increase was driven primarily by earnings from Spectra Energy Partners formed in July 2007.

EBIT. The $10 million increase reflects a gain on a customer bankruptcy settlement, higher earnings from expansion projects and higher commodity prices for gas processing associated with pipeline operations. These increases were partially offset by an increase in project development costs charged to expense and increased operating and administrative costs.

Distribution

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2008	2007	Increase (Decrease)	2008	2007	Increase (Decrease)
	(in millions, except where noted)					
Operating revenues	$280	$266	$ 14	$1,433	$1,330	$ 103
Operating expenses						
Natural gas purchased	97	98	(1)	747	726	21
Operating, maintenance and other	93	91	2	284	252	32
Depreciation and amortization	45	42	3	138	119	19
Gains on sales of other assets and other, net	—	5	(5)	—	5	(5)
Operating income	45	40	5	264	238	26
Other income and expenses, net	(1)	—	(1)	(1)	—	(1)
EBIT	$ 44	$ 40	$ 4	$ 263	$ 238	$ 25
Number of customers (thousands)				1,300	1,280	20
Heating degree days (Fahrenheit)	264	226	38	4,815	4,701	114
Pipeline throughput, Tbtu	153	137	16	631	590	41

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Three Months Ended September 30, 2008 as Compared to Same Period in 2007

Operating Revenues. The $14 million increase was driven primarily by:

- a $5 million increase due to growth in the number of customers,
- an $11 million increase from higher natural gas prices passed through to customers without a mark-up, and
- a $13 million increase in storage and transportation revenues primarily due to favorable market conditions and growth of the transmission system, partially offset by
- a $14 million decrease in customer usage of natural gas.

Natural Gas Purchased. The $1 million decrease was driven primarily by:

- an $11 million decrease in customer usage of natural gas, and
- a $4 million decrease related to fuel used in operations, partially offset by
- a $3 million increase due to growth in the number of customers, and
- an $11 million increase related to higher natural gas prices passed through to customers without a mark-up.

Depreciation and Amortization. The $3 million increase was due to a higher asset base resulting primarily from completion of Phase II of the Dawn-Trafalgar expansion.

Gains on Sales of Other Assets and Other, net. The $5 million decrease was due to a gain on the sale of land in 2007.

EBIT. The $4 million increase was primarily attributable to higher storage and transportation revenues.

Nine Months Ended September 30, 2008 as Compared to Same Period in 2007

Operating Revenues. The $103 million increase was driven primarily by:

- a $146 million increase resulting from a stronger Canadian dollar,
- a $30 million increase due to growth in the number of customers, and
- a $32 million increase in storage and transportation revenues primarily due to favorable market conditions and growth of the transmission system, partially offset by
- a $63 million decrease from lower natural gas prices passed through to customers without a mark-up,
- a $22 million decrease in customer usage of natural gas, and
- a $15 million decrease due to an unfavorable decision from the OEB on unregulated storage revenues in the second quarter of 2008.

Natural Gas Purchased. The $21 million increase was driven primarily by:

- an $85 million increase resulting from a stronger Canadian dollar, and
- a $28 million increase due to growth in the number of customers, partially offset by
- a $63 million decrease related to lower natural gas prices passed through to customers without a mark-up, and
- a $20 million decrease in customer usage of natural gas.

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Operating, Maintenance and Other. The $32 million increase was driven primarily by a stronger Canadian dollar.

Depreciation and Amortization. The $19 million increase was driven by:

- an $11 million increase resulting from a stronger Canadian dollar, and
- an $8 million increase due to a higher asset base resulting primarily from completion of Phase II of the Dawn-Trafalgar expansion.

Gains on Sales of Other Assets and Other, net. The $5 million decrease was due to a gain on the sale of land in 2007.

EBIT. The $25 million increase was primarily attributable to higher storage and transportation revenues and a stronger Canadian dollar.

Western Canada Transmission & Processing

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2008	2007	Increase (Decrease)	2008	2007	Increase (Decrease)
	(in millions, except where noted)					
Operating revenues	$397	$298	$ 99	$1,174	$852	$ 322
Operating expenses						
Natural gas and petroleum products purchased	136	67	69	384	240	144
Operating, maintenance and other	110	93	17	342	292	50
Depreciation and amortization	37	35	2	114	98	16
Operating income	114	103	11	334	222	112
Other income and expenses, net	(1)	(2)	1	—	—	—
Minority interest expense	—	—	—	1	4	(3)
EBIT	$113	$101	$ 12	$ 333	$218	$ 115
Pipeline throughput, Tbtu	150	144	6	454	436	18
Volumes processed, Tbtu	183	183	—	526	531	(5)
Empress inlet volumes, Tbtu	218	188	30	644	521	123

Three Months Ended September 30, 2008 Compared to Same Period in 2007

Operating Revenues. The $99 million increase was driven primarily by:

- an $89 million increase due to higher volumes and stronger NGL sales prices associated with the Empress operations, and
- a $4 million increase mainly due to higher processing volumes in the Pine River area of northeastern British Columbia.

Natural Gas and Petroleum Products Purchased. The $69 million increase was driven primarily by higher volumes and prices of natural gas purchased for the Empress facility.

Operating, Maintenance and Other. The $17 million increase was driven primarily by:

- a $7 million increase caused by timing of operating expenses between the quarters,
- a $3 million increase in plant fuel and electricity costs at the Empress facility, and
- a $3 million increase due to higher repairs and maintenance costs for processing plants.

EBIT. The $12 million increase was driven primarily by higher volumes and stronger NGL prices that benefited the Empress operations, partially offset by higher operating expenses.

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Nine Months Ended September 30, 2008 Compared to Same Period in 2007

Operating Revenues. The $322 million increase was driven primarily by:

- a $202 million increase primarily due to stronger NGL sales prices and higher volumes associated with the Empress operations,
- a $91 million increase resulting from a stronger Canadian dollar, and
- a $13 million increase mainly due to higher processing volumes in the Pine River area of northeastern British Columbia.

Natural Gas and Petroleum Products Purchased. The $144 million increase was driven by:

- a $115 million increase mainly from higher prices and volumes of natural gas purchased for the Empress facility, and
- a $28 million increase resulting from a stronger Canadian dollar.

Operating, Maintenance and Other. The $50 million increase was driven by:

- a $28 million increase resulting from a stronger Canadian dollar,
- an $11 million increase in plant fuel and electricity costs at the Empress facility, and
- a $4 million increase caused by higher repairs and maintenance costs for processing plants.

Depreciation and Amortization. The $16 million increase was driven primarily by:

- a $9 million increase resulting from a stronger Canadian dollar, and
- a $6 million increase due to increased pipeline depreciation rates as a result of a pipeline rate settlement as well as capital additions.

Minority Interest Expense. The $3 million decrease was driven primarily by the purchase of the Income Fund in the second quarter of 2008. Prior to the acquisition, the Income Fund indirectly held 54% of Spectra Energy's consolidated Midstream operations and Westcoast indirectly held the remaining 46%.

EBIT. The $115 million increase was driven primarily by higher NGL prices and volumes that benefited the Empress operations, and a stronger Canadian dollar.

Field Services

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2008	2007	Increase (Decrease)	2008	2007	Increase (Decrease)
	(in millions, except where noted)					
Equity in earnings of unconsolidated affiliates	239	140	99	647	345	302
EBIT	$ 239	$ 140	$ 99	$ 647	$ 345	$ 302
Natural gas gathered and processed/transported, Tbtu/d (a,b)	6.6	6.8	(0.2)	7.1	6.7	0.4
NGL production, MBbl/d (a,c)	340	365	(25)	365	358	7
Average natural gas price per MMBtu (d)	$10.24	$6.16	$ 4.08	$9.73	$6.83	$ 2.90
Average NGL price per gallon (e)	$ 1.44	$1.14	$ 0.30	$1.42	$1.02	$ 0.40

(a) Reflects 100% of volumes
(b) Trillion British thermal units per day
(c) Thousand barrels per day
(d) Million British thermal units. Average price based on NYMEX Henry Hub.
(e) Does not reflect results of commodity hedges

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Three Months Ended September 30, 2008 Compared to Same Period in 2007

EBIT. Higher equity in earnings of $99 million were primarily the result of the following variances, each representing Spectra Energy's 50% ownership portion of the earnings drivers at DCP Midstream:

- an $82 million increase from commodity-sensitive processing arrangements due to increased commodity prices,
- a $26 million increase in marketing margins related to derivative timing gains associated with gas marketing positions, and
- a $23 million increase in earnings from DCP Midstream Partners primarily as a result of mark-to-market gains on hedges used to protect distributable cash flows, partially offset by
- a $17 million decrease resulting primarily from increased operating and maintenance expenses due to growth, inflation and increased maintenance activity, and higher depreciation expense primarily attributable to asset acquisitions, partially offset by decreased general and administrative costs as a result of $3 million of costs in 2007 associated with DCP Midstream's initiative to create stand alone corporate functions separate from its two partners,
- an $11 million decrease in gathering and processing margins primarily attributable to decreased natural gas and NGL volumes as a result of hurricanes and adverse weather events, partially offset by increased gas and NGL volumes and improved system efficiencies in non weather-impacted areas, and
- a $4 million decrease due to higher net interest expense resulting from the increased debt associated with acquisitions in 2007.

Nine Months Ended September 30, 2008 Compared to Same Period in 2007

EBIT. Higher equity in earnings of $302 million were primarily the result of the following variances, each representing Spectra Energy's 50% ownership portion of the earnings drivers at DCP Midstream:

- a $317 million increase from commodity-sensitive processing arrangements, due to increased commodity prices, and
- a $28 million increase in gathering and processing margins primarily attributable to increased natural gas volumes, partially due to lower natural gas volumes in 2007 from the effects of severe weather, as well as increased NGL volumes due to improved plant efficiencies, partially offset by decreased natural gas and NGL volumes as a result of hurricanes and adverse weather events, partially offset by
- a $27 million decrease resulting from increased operating and maintenance expenses due to growth, inflation and increased maintenance activity, and higher depreciation expense primarily attributable to asset acquisitions, partially offset by decreased general and administrative costs as a result of $9 million of costs in 2007 associated with DCP Midstream's initiative to create stand alone corporate functions separate from its two partners,
- a $13 million decrease due to higher net interest expense resulting from the increased debt associated with acquisitions in 2007, and
- a $7 million decrease in earnings from DCP Midstream Partners primarily as a result of mark-to-market losses on hedges used to protect distributable cash flows.

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Other

	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Increase (Decrease)	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007	Increase (Decrease)
	(in millions, except where noted)					
Operating revenues	$11	$ 8	$ 3	$ 32	$ 23	$ 9
Operating expenses	19	25	(6)	85	85	—
Operating loss	(8)	(17)	9	(53)	(62)	9
Other income and expenses, net	(1)	2	(3)	(4)	6	(10)
EBIT	$ (9)	$(15)	$ 6	$(57)	$(56)	$ (1)

Three Months Ended September 30, 2008 as Compared to Same Period in 2007

EBIT. The 2007 period included $5 million of costs associated with the spin-off of Spectra Energy. The 2008 third quarter results included a benefit for the favorable resolution of an insurance contingency offset by higher benefit costs in 2008 when compared to 2007.

Nine Months Ended September 30, 2008 as Compared to Same Period in 2007

EBIT. The 2007 period included $16 million of costs associated with the spin-off of Spectra Energy. Excluding these costs, EBIT was lower by $17 million primarily as a result of a benefit recognized from the favorable resolution of a legal matter in 2007 and higher benefits and incentive costs in 2008.

LIQUIDITY AND CAPITAL RESOURCES

Operating Cash Flows

Net cash provided by operating activities increased $544 million to $1,396 million for the nine months ended September 30, 2008 compared to the same period in 2007. This change was driven primarily by:

- an increase of $312 million in distributions received from unconsolidated affiliates in 2008, primarily from DCP Midstream, and
- a January 2007 payment of $100 million, which was accrued at December 31, 2006, to resolve certain litigation matters associated with discontinued LNG operations.

Net working capital was negative $737 million as of September 30, 2008, which included short-term borrowings and commercial paper totaling $913 million and current maturities of long-term debt of $221 million. Spectra Energy will rely upon cash flows from operations and additional financing transactions to fund its liquidity and capital requirements for the next 12 months including issuances of short-term and long-term debt. See also Financing Cash Flows and Liquidity for discussions of effective shelf registrations, available credit facilities and new debt issuances.

Capital market declines experienced during the third quarter of 2008 have adversely impacted the market value of investment assets used to fund Spectra Energy's defined benefit employee retirement plans. Given the current volatility of capital market returns, Spectra Energy is unable to determine the impact of such market returns on future funding requirements or expense levels for 2009 and beyond. However, based on activity through the third quarter of 2008, management believes there will be no material impacts on Spectra Energy's consolidated results of operations, financial position or liquidity.

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Investing Cash Flows

Cash flows used in investing activities increased $447 million to $1,564 million in the first nine months of 2008 compared to the same period in 2007. This change was driven primarily by:

- a $595 million increase in capital and investment expenditures in 2008 as a result of expansion projects underway at each of Spectra Energy's segments, and
- the $274 million acquisition on May 1, 2008 of the units of the Income Fund that were held by non-affiliated holders, partially offset by
- a net increase of $268 million in proceeds from the sales and maturities of available-for-sale securities primarily at Spectra Energy Partners, and
- distributions received from DCP Midstream of $179 million in 2008 representing a return of capital.

	Nine Months Ended September 30,	
	2008	2007
	(in millions)	
Capital and Investment Expenditures		
U.S. Transmission	$ 1,098	$ 573
Distribution	274	224
Western Canada Transmission & Processing	139	114
Other	24	29
Total	$ 1,535	$ 940

Capital and investment expenditures for the nine months ended September 30, 2008 consisted of $1,224 million for expansion projects and $311 million for maintenance and other projects.

Spectra Energy continues to project 2008 capital and investment expenditures of approximately $2.2 billion, consisting of approximately $1.5 billion for U.S. Transmission, $0.4 billion for Distribution and $0.3 billion for Western Canada Transmission & Processing. These expenditures exclude the Income Fund acquisition. Total projected 2008 capital and investment expenditures include approximately $1.6 billion of expansion capital expenditures and $0.6 billion for maintenance and upgrades of existing plants, pipelines and infrastructure to serve growth. Spectra Energy expects to place into service approximately $1.8 billion of capital expansion projects in 2008.

Financing Cash Flows and Liquidity

Net cash provided by financing activities totaled $354 million in the first nine months of 2008 compared to $39 million in the first nine months of 2007. This change was driven primarily by:

- a $185 million increase in short-term borrowings in the 2008 period compared to the 2007 period and
- a $938 million increase in net issuances of long-term debt in 2008 compared to the 2007 period, partially offset by
- repurchases of Spectra Energy common shares in 2008 of $600 million, and
- proceeds of $230 million in 2007 from the issuance of Spectra Energy Partners common shares.

Long-term Debt Issuances/Retirements. See Note 13 of Notes to Condensed Consolidated Financial Statements for a discussion of significant long-term debt issuances and retirements.

Common Stock Repurchases. As previously discussed, Spectra Energy repurchased a cumulative total of $600 million of its outstanding common stock during the second and third quarters of 2008, and its share repurchase program was concluded on August 8, 2008.

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Available Credit Facilities and Restrictive Debt Covenants. Commercial paper markets in the U.S. and Canada have recently experienced varying degrees of credit volatility and contraction that has limited the demand for commercial paper and reduced the ability of Spectra Energy to issue commercial paper. This volatility has been caused by many factors, including concerns about creditworthiness in the overall market, especially the financial services sector, which has culminated in the failure or consolidation of several large financial and investment institutions. During this credit contraction, Spectra Energy has been able to issue commercial paper or draw on its committed and available credit facilities in amounts sufficient to fund liquidity needs. Spectra Energy's commercial paper borrowings are not asset-backed nor are they related to real estate financing, the two sectors facing the most severe credit contraction.

Spectra Energy and its subsidiaries have outstanding credit facilities with an aggregate of approximately $2.7 billion in bank commitments, of which approximately $80 million ($64 million unfunded) were allocated to Lehman Brothers Commercial Bank (Lehman) as of September 30, 2008. Following the bankruptcy filing of its parent, Lehman defaulted on its obligations to fund advances under the Spectra Capital credit facility. As a result of the default, Spectra Capital has the right to replace the lender. Spectra Energy and its subsidiaries are working to identify replacement lenders for the remaining portion of its credit facility commitments currently held by Lehman. Spectra Energy believes that the commitments of the other lenders under Spectra Energy's and its subsidiaries' credit facilities are sufficient to fund working capital and short-term requirements and that default by Lehman does not materially affect the liquidity of Spectra Energy.

See Note 13 for a summary of available credit facilities and related financial and other covenants.

Credit Ratings. The short-term and long-term debt of Spectra Energy and certain subsidiaries are rated by Standard & Poor's (S&P), Moody's Investors Service (Moody's) and Dominion Bond Rating Service (DBRS).

Credit Ratings Summary as of October 31, 2008	Standard and Poor's	Moody's Investor Service	Dominion Bond Rating Service
Spectra Energy Capital, LLC (a)	BBB	Baa1	Not applicable
Texas Eastern Transmission, LP (a)	BBB+	A3	Not applicable
Westcoast Energy Inc. (a)	BBB+	Not applicable	A (low)
Union Gas Limited (a)	BBB+	Not applicable	A
Maritimes & Northeast Pipeline, LP (b)	A	A2	A

(a) Senior unsecured credit rating
(b) Senior secured credit rating

The above credit ratings are dependent upon, among other factors, the ability to generate sufficient cash to fund capital and investment expenditures, while maintaining the strength of the current balance sheets. These credit ratings could be negatively impacted if, as a result of market conditions or other factors, they are unable to maintain the current balance sheet strength or if earnings or cash flow outlooks deteriorate materially.

Dividends. Spectra Energy currently anticipates a dividend payout ratio of approximately 60% of estimated annual net income per share of common stock. The declaration and payment of dividends is subject to the sole discretion of Spectra Energy's Board of Directors and will depend upon many factors, including the financial condition, earnings and capital requirements of our operating subsidiaries, covenants associated with certain debt obligations, legal requirements, regulatory constraints and other factors deemed relevant by the Board of Directors. On July 3, 2008, Spectra Energy declared a 9% increase in its quarterly dividend from $0.23 to $0.25 per common share. The new annual dividends are $1.00 per share, representing a nearly 14% increase over the 2007 annualized level of $0.88 per share. A dividend of $0.25 per common share was declared on October 28, 2008 and will be paid on December 15, 2008.

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Union Gas Preference Share Redemption. Subject to approval of the OEB, Union Gas anticipates it will redeem all of its issued and outstanding preference shares on January 1, 2009 in order to implement a new corporate legal structure. It is estimated that the redemption will cost approximately 110 million Canadian dollars (approximately $103 million) and will be financed through a combination of available cash, cash generated from operations and available credit facilities. These preference shares are classified as Minority Interests on the Condensed Consolidated Balance Sheets.

Other Matters. Spectra Energy has an automatic shelf registration statement on file with the SEC to register the issuance of unspecified amounts of various equity and debt securities by Spectra Energy. In addition, as of the date of this filing, subsidiaries of Spectra Energy had 800 million Canadian dollars (approximately $750 million) available under shelf registrations for issuances in the Canadian market, of which 400 million expires in August 2010 and 400 million expires in September 2010.

OTHER ISSUES

New Accounting Pronouncements

See Note 20 for discussion.

Subsequent Events

See Note 21 for discussion.

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Item 3. Quantitative and Qualitative Disclosures about Market Risk.

In Item 7A of Spectra Energy's Annual Report on Form 10-K for the year ended December 31, 2007, Spectra Energy estimated its 2008 NGL-related oil price sensitivity at approximately $135 million of annual pre-tax earnings per a $10 move in oil prices at Spectra Energy's forecasted NGL-to-oil price relationship. However, NGL prices have lagged oil prices during oil's unprecedented upward price movement earlier this year. Assuming crude oil prices average approximately $100 per barrel, each 1% change in the price relationship between NGLs and crude oil would change Spectra Energy's annual pre-tax earnings by approximately $18 million. At crude oil prices above $100 per barrel, the impact of a 1% change in the crude oil/NGL relationship would increase, and at crude oil prices below $100 per barrel, the impact of a 1% change in the crude oil/NGL relationship would decrease.

Recently, there have been significant equity and commodity market declines driven by general economic factors and credit concerns, primarily in the financial services sector. Spectra Energy continues to utilize its established risk management policies and procedures to ensure the appropriate monitoring of customer credit positions and, based on current evaluations, does not expect any significant negative impacts associated with these positions. In addition, Spectra Energy does not have a material amount of assets recorded at market value in its consolidated balance sheet, and therefore does not expect any significant effect from the market volatility currently being experienced.

Other than described above, management believes Spectra Energy's exposure to market risk has not changed materially at September 30, 2008.

Item 4. Controls and Procedures.

Evaluation of Disclosure Controls and Procedures

Disclosure controls and procedures are controls and other procedures that are designed to ensure that information required to be disclosed by Spectra Energy in the reports it files or submits under the Securities Exchange Act of 1934 (Exchange Act) is recorded, processed, summarized, and reported, within the time periods specified by the SEC's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to provide reasonable assurance that information required to be disclosed by Spectra Energy in the reports it files or submits under the Exchange Act is accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer, Spectra Energy has evaluated the effectiveness of its disclosure controls and procedures (as such term is defined in Rule 13a-15(e) and 15d-15(e) under the Exchange Act) as of September 30, 2008, and, based upon this evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that these controls and procedures are effective.

Changes in Internal Control over Financial Reporting

Under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer, Spectra Energy has evaluated changes in internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that occurred during the fiscal quarter ended September 30, 2008 and found no change that has materially affected, or is reasonably likely to materially affect, internal control over financial reporting.

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PART II. OTHER INFORMATION

Item 1. Legal Proceedings.

For information regarding material legal proceedings, see Note 16 of Notes to Condensed Consolidated Financial Statements.

Item 1A. Risk Factors.

In addition to the other information set forth in this report, careful consideration should be given to the factors discussed in Part I, "Item 1A. Risk Factors" in Spectra Energy's Annual Report on Form 10-K for the year ended December 31, 2007, which could materially affect Spectra Energy's financial condition or future results. Other than the updated NGL-to-oil price relationship sensitivity as previously discussed in "Item 3. Quantitative and Qualitative Disclosures about Market Risk," there were no changes to those risk factors at September 30, 2008.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds.

Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased (a)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Dollar Value of Shares that may yet be Purchased under the Plans or Programs
April 1 – April 30, 2008	—	—	—	—
May 1 – May 31, 2008	3,139,665	$ 27.10	3,139,665	—
June 1 – June 30, 2008	7,360,507	26.96	7,360,507	—
July 1 – July 31, 2008	7,980,639	26.74	7,980,639	—
August 1 – August 31, 2008	3,848,933	26.78	3,848,933	—
September 1 – September 30, 2008	—	—	—	—
Total	22,329,744	26.87	22,329,744	—

(a) On May 6, 2008, Spectra Energy's Board of Directors authorized a share repurchase program of up to $600 million under which purchases of Spectra Energy common stock under the program were made from time to time in the open market. During the second and third quarters of 2008, Spectra Energy repurchased the cumulative authorized limit of $600 million of common shares, and the share repurchase program was concluded on August 8, 2008.

Item 4. Submission of Matters to a Vote of Security Holders.

None.

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Item 6. Exhibits.

(a) Exhibits

Exhibit Number	
*31.1	Certification of the Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	Certification of the Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32.1	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.2	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith.

The total amount of securities of the registrant or its subsidiaries authorized under any instrument with respect to long-term debt not filed as an exhibit does not exceed 10% of the total assets of the registrant and its subsidiaries on a consolidated basis. The registrant agrees, upon request of the Securities and Exchange Commission, to furnish copies of any or all of such instruments to it.

Docket No. RP09-_____-000
Exhibit No. HIO-74
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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

SPECTRA ENERGY CORP

Date: November 7, 2008

/s/ FRED J. FOWLER

Fred J. Fowler
President and Chief Executive Officer

Date: November 7, 2008

/s/ GREGORY L. EBEL

Gregory L. Ebel
Group Executive and Chief Financial Officer

SE 10-K/A 12/31/2007

Section 1: 10-K/A (AMENDED FORM 10-K FOR FISCAL YEAR ENDED DECEMBER 31, 2007)

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K/A
Amendment No. 1

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2007 or

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from ___________ to ___________

Commission file number 1-33007

SPECTRA ENERGY CORP
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	20-5413139 (I.R.S. Employer Identification No.)
5400 Westheimer Court, Houston, Texas (Address of principal executive offices)	77056 (Zip Code)

713-627-5400
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, par value $0.001	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer," and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☒

Estimated aggregate market value of the common equity held by nonaffiliates of the registrant at June 30, 2007: $16,400,000,000.

Number of shares of Common Stock, $0.001 par value, outstanding at February 19, 2008: 632,536,965

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Explanatory Note

This Amendment No. 1 to the Annual Report on Form 10-K of Spectra Energy Corp (Spectra Energy) for the fiscal year ended December 31, 2007 is being filed for the purpose of providing separate audited financial statements and the related schedule of DCP Midstream, LLC in accordance with Rule 3-09 of Regulation S-X. These audited financial statements and the related schedule are included in Item 15. Exhibits and Financial Statement Schedule. This amendment does not update or modify in any way the results of operations, financial position, cash flows or other disclosures in Spectra Energy's Annual Report on Form 10-K for the fiscal year ended December 31, 2007, and does not reflect events occurring after the original filing date of said Form 10-K of February 29, 2008.

Item 15. Exhibits, Financial Statement Schedules.

(a)(1) Financial Statements

The following financial statements and supplemental schedules were filed as part of Spectra Energy's Form 10-K filed February 29, 2008:

Spectra Energy Corp:
- Report of Independent Registered Accounting Firm
- Consolidated Statements of Operations for the Years Ended December 31, 2007, 2006 and 2005
- Consolidated Balance Sheets as of December 31, 2007 and 2006
- Consolidated Statements of Cash Flows for the Years Ended December 31, 2007, 2006 and 2005
- Consolidated Statements of Stockholders'/Member's Equity and Comprehensive Income for the Years Ended December 31, 2007, 2006 and 2005
- Notes to the Consolidated Financial Statements

TEPPCO Partners, L.P.:
- Report of Independent Registered Public Accounting Firm
- Consolidated Balance Sheets as of December 31, 2005 and 2004
- Consolidated Statements of Income for the Years Ended December 31, 2005, 2004 and 2003
- Consolidated Statements of Cash Flows for the Years Ended December 31, 2005, 2004 and 2003
- Consolidated Statements of Partners' Capital for the Years Ended December 31, 2005, 2004 and 2003
- Consolidated Statements of Comprehensive Income for the Years Ended December 31, 2005, 2004 and 2003
- Notes to Consolidated Financial Statements

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The following financial statements are included herein:

DCP Midstream, LLC:
Independent Auditors' Report
Consolidated Balance Sheets as of December 31, 2007 and 2006
Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2007, 2006 and 2005
Consolidated Statements of Cash Flows for the Years Ended December 31, 2007, 2006 and 2005
Consolidated Statements of Members' Equity for the Years Ended December 31, 2007, 2006 and 2005
Notes to Consolidated Financial Statements

(a)(2) Financial Statement Schedules

The following financial statement schedule was filed as part of Spectra Energy's Form 10-K filed February 29, 2008:

Spectra Energy Corp:
Consolidated Financial Statement Schedule II—Valuation and Qualifying Accounts and Reserves for the Years Ended December 31, 2007, 2006 and 2005

The following financial statement schedule is included herein:

DCP Midstream, LLC:
Consolidated Financial Statement Schedule II—Valuation and Qualifying Accounts and Reserves for the Years Ended December 31, 2007, 2006 and 2005

(a)(3) Exhibits — See Exhibit Index immediately following the signature page.

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Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

SPECTRA ENERGY CORP

Date: March 20, 2008

/s/ Gregory L. Ebel
Gregory L. Ebel
Group Executive and Chief Executive Officer

EXHIBIT INDEX

Exhibit No.	Exhibit Description
*23.1	Consent of Independent Auditors.
*31.1	Certification of the Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	Certification of the Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32.1	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.2	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith.

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DCP MIDSTREAM, LLC
CONSOLIDATED FINANCIAL STATEMENTS

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INDEPENDENT AUDITORS' REPORT

To the Board of Directors and Members of
DCP Midstream, LLC
Denver, Colorado

We have audited the accompanying consolidated balance sheets of DCP Midstream, LLC and subsidiaries as of December 31, 2007 and 2006, and the related consolidated statements of operations and comprehensive income, members' equity, and cash flows for each of the three years in the period ended December 31, 2007. Our audits also included the financial statement schedule listed in the Index at Item 15. These consolidated financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of DCP Midstream, LLC and subsidiaries at December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007 in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/s/ Deloitte & Touche LLP

Denver, Colorado
March 7, 2008 (March 20, 2008 as to the offering described in Note 19)

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DCP MIDSTREAM, LLC

CONSOLIDATED BALANCE SHEETS
As of December 31, 2007 and 2006
(millions)

	2007	2006
ASSETS		
Current assets:		
Cash and cash equivalents	$ 71	$ 68
Short-term investments	9	437
Accounts receivable:		
Customers, net of allowance for doubtful accounts of $5 million and $3 million, respectively	1,254	933
Affiliates	386	283
Other	48	56
Inventories	117	87
Unrealized gains on mark-to-market and hedging instruments	301	242
Other	62	23
Total current assets	2,248	2,129
Property, plant and equipment, net	4,443	3,869
Restricted investments	101	102
Investments in unconsolidated affiliates	204	204
Intangible assets, net	312	58
Goodwill	556	421
Unrealized gains on mark-to-market and hedging instruments	69	29
Deferred income taxes	7	4
Other non-current assets	38	33
Other non-current assets—affiliates	27	47
Total assets	$8,005	$6,896
LIABILITIES AND MEMBERS' EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$1,499	$1,490
Affiliates	122	92
Other	54	42
Unrealized losses on mark-to-market and hedging instruments	347	216
Distributions payable to members	123	127
Accrued interest payable	56	47
Accrued taxes	55	27
Other	204	136
Total current liabilities	2,460	2,177
Deferred income taxes	16	17
Long-term debt	2,930	2,115
Unrealized losses on mark-to-market and hedging instruments	120	33
Other long-term liabilities	323	226
Non-controlling interests	193	71
Commitments and contingent liabilities		
Members' equity:		
Members' interest	1,974	2,107
Retained earnings	—	153
Accumulated other comprehensive loss	(11)	(3)
Total members' equity	1,963	2,257
Total liabilities and members' equity	$8,005	$6,896

See Notes to Consolidated Financial Statements.

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DCP MIDSTREAM, LLC

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
Years Ended December 31, 2007, 2006 and 2005
(millions)

	2007	2006	2005
Operating revenues:			
Sales of natural gas and petroleum products	$10,009	$ 9,137	$10,011
Sales of natural gas and petroleum products to affiliates	2,884	2,813	2,785
Transportation, storage and processing	304	308	253
Trading and marketing (losses) gains, net	(43)	77	(15)
Total operating revenues	13,154	12,335	13,034
Operating costs and expenses:			
Purchases of natural gas and petroleum products	10,097	9,322	10,133
Purchases of natural gas and petroleum products from affiliates	781	789	830
Operating and maintenance	510	462	447
Depreciation and amortization	316	284	287
General and administrative	258	234	195
Gain on sale of assets	(3)	(28)	(2)
Total operating costs and expenses	11,959	11,063	11,890
Operating income	1,195	1,272	1,144
Gain on sale of general partner interest in TEPPCO	—	—	1,137
Equity in earnings of unconsolidated affiliates	29	20	22
Non-controlling interest in loss (income)	15	(15)	1
Interest income	16	26	26
Interest expense	(170)	(145)	(154)
Income before income taxes	1,085	1,158	2,176
Income tax expense	(11)	(23)	(9)
Income from continuing operations	1,074	1,135	2,167
Income from discontinued operations, net of income taxes	—	—	3
Net income	1,074	1,135	2,170
Other comprehensive (loss) income:			
Foreign currency translation adjustment	—	—	(8)
Canadian business distributed to Duke Energy	—	—	(70)
Net unrealized (losses) gains on cash flow hedges	(8)	5	—
Reclassification of cash flow hedges into earnings	—	—	1
Total other comprehensive (loss) income	(8)	5	(77)
Total comprehensive income	$ 1,066	$ 1,140	$ 2,093

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DCP MIDSTREAM, LLC

CONSOLIDATED STATEMENTS OF CASH FLOWS
Years Ended December 31, 2007, 2006 and 2005
(millions)

	2007	2006	2005
Cash flows from operating activities:			
Net income	$ 1,074	$ 1,135	$ 2,170
Adjustments to reconcile net income to net cash provided by operating activities:			
Income from discontinued operations	—	—	(3)
Gain from sale of equity investment in TEPPCO	—	—	(1,137)
Gain on sale of assets	(3)	(28)	(2)
Depreciation and amortization	316	284	287
Equity in earnings of unconsolidated affiliates, net of distributions	3	—	15
Deferred income tax (benefit) expense	(1)	17	(2)
Non-controlling interest in (loss) income	(15)	15	(1)
Other, net	11	(3)	2
Changes in operating assets and liabilities which provided (used) cash, net of effects from acquisitions:			
Accounts receivable	(398)	314	(432)
Inventories	(30)	23	(37)
Net unrealized losses (gains) on mark-to-market and hedging instruments	99	(1)	9
Accounts payable	33	(495)	910
Accrued interest payable	9	1	(14)
Other	50	(16)	(12)
Net cash provided by continuing operations	1,148	1,246	1,753
Net cash provided by discontinued operations	—	—	11
Net cash provided by operating activities	1,148	1,246	1,764
Cash flows from investing activities:			
Capital and acquisition expenditures	(600)	(325)	(212)
Acquisition of Momentum Energy Group, Inc., net of cash acquired	(604)	—	—
Investments in unconsolidated affiliates	(4)	(44)	(24)
Distributions from unconsolidated affiliates	—	2	—
Purchases of available-for-sale securities	(15,812)	(19,666)	(17,986)
Proceeds from sales of available-for-sale securities	16,243	20,121	17,260
Proceeds from sales of assets	1	81	53
Proceeds from sale of general partner interest in TEPPCO	—	—	1,100
Other	2	—	9
Net cash (used in) provided by continuing operations	(774)	169	200
Net cash used in discontinued operations	—	—	(13)
Net cash (used in) provided by investing activities	(774)	169	187
Cash flows from financing activities:			
Payment of dividends and distributions to members	(1,364)	(1,451)	(2,313)
Proceeds from issuance of equity securities of a subsidiary, net of offering costs	229	—	206
Contribution received from ConocoPhillips	—	—	398
Proceeds from debt	1,477	378	408
Payment of debt	(667)	(320)	(607)
Payment of debt acquired	(20)	—	—
Loans made to Duke Capital LLC and ConocoPhillips	—	—	(1,100)
Repayment of loans by Duke Capital LLC and ConocoPhillips	—	—	1,100
Net cash paid to non-controlling interests	(22)	(10)	3
Other	(4)	(3)	(2)
Net cash used in continuing operations	(371)	(1,406)	(1,907)
Net cash used in discontinued operations	—	—	(44)
Net cash used in financing activities	(371)	(1,406)	(1,951)
Net increase in cash and cash equivalents	3	9	—
Cash and cash equivalents, beginning of period	68	59	59
Cash and cash equivalents, end of period	$ 71	$ 68	$ 59

See Notes to Consolidated Financial Statements.

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DCP MIDSTREAM, LLC

CONSOLIDATED STATEMENTS OF MEMBERS' EQUITY
Years Ended December 31, 2007, 2006 and 2005
(millions)

	Members' Interest	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balance, January 1, 2005	$ 1,709	$ 909	$ 69	$ 2,687
Dividends and distributions	—	(2,414)	—	(2,414)
Distribution of Canadian business	—	(254)	(70)	(324)
Contributions	398	—	—	398
Net income	—	2,170	—	2,170
Foreign currency translation adjustment	—	—	(8)	(8)
Reclassification of cash flow hedges into earnings	—	—	1	1
Balance, December 31, 2005	2,107	411	(8)	2,510
Dividends and distributions	—	(1,393)	—	(1,393)
Net income	—	1,135	—	1,135
Net unrealized gains on cash flow hedges	—	—	5	5
Balance, December 31, 2006	2,107	153	(3)	2,257
Dividends and distributions	(133)	(1,227)	—	(1,360)
Net income	—	1,074	—	1,074
Net unrealized losses on cash flow hedges	—	—	(8)	(8)
Balance, December 31, 2007	$ 1,974	$ —	$ (11)	$ 1,963

See Notes to Consolidated Financial Statements.

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DCP MIDSTREAM, LLC

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2007, 2006 AND 2005**

1. General and Summary of Significant Accounting Policies

Basis of Presentation—DCP Midstream, LLC, with its consolidated subsidiaries, us, we, our, or the Company, is a joint venture owned 50% by Spectra Energy Corp, or Spectra Energy, and 50% by ConocoPhillips. We operate in the midstream natural gas industry. Our primary operations consist of natural gas gathering, processing, compression, transportation and storage, and natural gas liquid, or NGL, fractionation, transportation, gathering, treating, processing and storage, as well as marketing, from which we generate revenues primarily by trading and marketing natural gas and NGLs.

We formed DCP Midstream Partners, LP, a master limited partnership, or DCP Partners, of which our subsidiary, DCP Midstream GP, LP, acts as general partner. DCP Partners completed their initial public offering in December 2005. As of December 31, 2007 and 2006, respectively, we owned a 33.9% and 40.7% limited partnership interest and a 1.5% and 2.0% general partnership interest in DCP Partners, as well as incentive distribution rights that entitle us to receive an increasing share of available cash when pre-defined distribution targets are achieved. As the general partner of DCP Partners, we have responsibility for its operations. Since we exercise control over DCP Partners, we account for them as a consolidated subsidiary.

Prior to January 2, 2007, we were owned 50% by Duke Energy Corporation, or Duke Energy. On January 2, 2007, Duke Energy created two separate publicly traded companies by spinning off their natural gas businesses, including their 50% ownership interest in us, to Duke Energy shareholders. As a result of this transaction, Duke Energy's 50% ownership interest in us was transferred to a new company, Spectra Energy. This transaction is referred to in this report as "the Spectra spin." For periods prior to January 2, 2007, references to Spectra Energy are interchangeable with Duke Energy. Effective January 2, 2007, Spectra Energy refers to the newly formed public company.

In July 2005, Duke Energy transferred a 19.7% interest in us to ConocoPhillips in exchange for direct and indirect monetary and non-monetary consideration, effectively decreasing Duke Energy's membership interest in us to 50% and increasing ConocoPhillips' membership interest in us to 50%, referred to as "the 50-50 Transaction." Included in this transaction, we distributed to Duke Energy substantially all of our Canadian business, made a disproportionate cash distribution of approximately $1,100 million to Duke Energy using the proceeds from the sale of our general partner interest in TEPPCO Partners L.P., or TEPPCO, and paid a $245 million proportionate distribution to Duke Energy and ConocoPhillips. In addition, ConocoPhillips contributed cash of $398 million to us. Under the terms of the Second Amended and Restated LLC Agreement dated July 5, 2005, as amended, or the LLC Agreement, proceeds from this contribution were designated for the acquisition or improvement of property, plant and equipment. At December 31, 2007 and 2006, there were no remaining restricted investment balances related to this contribution.

We are governed by a five member board of directors, consisting of two voting members from each parent and our Chief Executive Officer and President, a non-voting member. All decisions requiring board of directors' approval are made by simple majority vote of the board, but must include at least one vote from both a Spectra Energy and ConocoPhillips board member. In the event the board cannot reach a majority decision, the decision is appealed to the Chief Executive Officers of both Spectra Energy and ConocoPhillips.

The consolidated financial statements include the accounts of the Company and all majority-owned subsidiaries where we have the ability to exercise control, variable interest entities where we are the primary beneficiary, and undivided interests in jointly owned assets. We also consolidate DCP Partners, which we control as the general partner and where the limited partners do not have substantive kick-out or participating rights.

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DCP MIDSTREAM, LLC

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — Continued
YEARS ENDED DECEMBER 31, 2007, 2006 AND 2005

Investments in greater than 20% owned affiliates that are not variable interest entities and where we do not have the ability to exercise control, and investments in less than 20% owned affiliates where we have the ability to exercise significant influence, are accounted for using the equity method. Intercompany balances and transactions have been eliminated.

Use of Estimates—Conformity with accounting principles generally accepted in the United States of America, or GAAP, requires management to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and notes. Although these estimates are based on management's best available knowledge of current and expected future events, actual results could be different from these estimates.

Cash and Cash Equivalents—Cash and cash equivalents includes all cash balances and highly liquid investments with an original maturity of three months or less.

Short-Term and Restricted Investments—We may invest available cash balances in various financial instruments, such as commercial paper, money market instruments and tax-exempt debt securities that have stated maturities of 20 years or more. These instruments provide for a high degree of liquidity through features, which allow for the redemption of the investment at its face amount plus earned income. As we generally intend to sell these instruments within one year or less from the balance sheet date, and as they are available for use in current operations, they are classified as current assets, unless otherwise restricted. We have classified all short-term and restricted debt investments as available-for-sale and they are carried at fair market value. Unrealized gains and losses on available-for-sale securities are recorded in the consolidated balance sheets as accumulated other comprehensive income (loss), or AOCI. No such gains or losses were deferred in AOCI at December 31, 2007 or 2006. Restricted investments consist of collateral for DCP Partners' term loan. The costs, including accrued interest on investments, approximates fair value due to the short-term, highly liquid nature of the securities held by us and as interest rates are re-set on a daily, weekly or monthly basis.

Inventories—Inventories consist primarily of natural gas and NGLs held in storage for transportation and processing and sales commitments. Inventories are valued at the lower of weighted average cost or market. Transportation costs are included in inventory on the consolidated balance sheets.

Accounting for Risk Management and Derivative Activities and Financial Instruments—Effective July 1, 2007, we elected to discontinue using the hedge method of accounting for our commodity cash flow hedges. We are using the mark-to-market method of accounting for all commodity derivative instruments beginning in July 2007. As a result, the remaining net loss deferred in AOCI is being reclassified to sales of natural gas and petroleum products through December 2011, as the derivative transactions impact earnings.

Each derivative not qualifying for the normal purchases and normal sales exception is recorded on a gross basis in the consolidated balance sheets at its fair value as unrealized gains or unrealized losses on mark-to-market and hedging instruments. Derivative assets and liabilities remain classified in the consolidated balance sheets as unrealized gains or unrealized losses on mark-to-market and hedging instruments at fair value until the contractual delivery period impacts earnings.

We designate each energy commodity derivative as either trading or non-trading. Certain non-trading derivatives are further designated as either a hedge of a forecasted transaction or future cash flow (cash flow hedge), a hedge of a recognized asset, liability or firm commitment (fair value hedge), or a normal purchase or normal sale contract, while certain non-trading derivatives, which are related to asset based activity, are

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DCP MIDSTREAM, LLC

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — Continued
YEARS ENDED DECEMBER 31, 2007, 2006 AND 2005

non-trading mark-to-market derivatives. For each of our derivatives, the accounting method and presentation in the consolidated statements of operations and comprehensive income are as follows:

Classification of Contract	Accounting Method	Presentation of Gains & Losses or Revenue & Expense
Trading Derivatives	Mark-to-market method[b]	Net basis in trading and marketing gains and losses
Non-Trading Derivatives:		
Cash Flow Hedge[a]	Hedge method[c]	Gross basis in the same consolidated statements of operations and comprehensive income category as the related hedged item
Fair Value Hedge	Hedge method[c]	Gross basis in the same consolidated statements of operations and comprehensive income category as the related hedged item
Normal Purchase or Normal Sale	Accrual method[d]	Gross basis upon settlement in the corresponding consolidated statements of operations and comprehensive income category based on purchase or sale
Non-Trading Derivatives	Mark-to-market method[b]	Net basis in trading and marketing gains and losses

a Effective July 1, 2007, all commodity cash flow hedges are classified as non-trading derivative activity. Our interest rate swaps continue to be accounted for as cash flow hedges.

b Mark-to-market—An accounting method whereby the change in the fair value of the asset or liability is recognized in the consolidated statements of operations and comprehensive income in trading and marketing gains and losses during the current period.

c Hedge method—An accounting method whereby the change in the fair value of the asset or liability is recorded in the consolidated balance sheets as unrealized gains or unrealized losses on mark-to-market and hedging instruments. For cash flow hedges, there is no recognition in the consolidated statements of operations and comprehensive income for the effective portion until the service is provided or the associated delivery period impacts earnings. For fair value hedges, the changes in the fair value of the asset or liability, as well as the offsetting changes in value of the hedged item, are recognized in the consolidated statements of operations and comprehensive income in the same category as the related hedged item.

d Accrual method—An accounting method whereby there is no recognition in the consolidated balance sheets or consolidated statements of operations and comprehensive income for changes in fair value of a contract until the service is provided or the associated delivery period impacts earnings.

Cash Flow and Fair Value Hedges—For derivatives designated as a cash flow hedge or a fair value hedge, we maintain formal documentation of the hedge. In addition, we formally assess both at the inception of the hedge and on an ongoing basis, whether the hedge contract is highly effective in offsetting changes in cash flows or fair values of hedged items. All components of each derivative gain or loss are included in the assessment of hedge effectiveness, unless otherwise noted.

The fair value of a derivative designated as a cash flow hedge is recorded in the consolidated balance sheets as unrealized gains or unrealized losses on mark-to-market and hedging instruments. The effective portion of the change in fair value of a derivative designated as a cash flow hedge is recorded in the consolidated balance sheets as AOCI and the ineffective portion is recorded in the consolidated statements of operations and comprehensive income. During the period in which the hedged transaction impacts earnings, amounts in AOCI associated with the hedged transaction are reclassified to the consolidated statements of operations and comprehensive income in

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the same accounts as the item being hedged. We discontinue hedge accounting prospectively when it is determined that the derivative no longer qualifies as an effective hedge, or when it is probable that the hedged transaction will not occur. When hedge accounting is discontinued because the derivative no longer qualifies as an effective hedge, the derivative is subject to the mark-to-market accounting method prospectively. The derivative continues to be carried on the consolidated balance sheets at its fair value; however, subsequent changes in its fair value are recognized in current period earnings. Gains and losses related to discontinued hedges that were previously accumulated in AOCI will remain in AOCI until the hedged transaction impacts earnings, unless it is probable that the hedged transaction will not occur, in which case, the gains and losses that were previously deferred in AOCI will be immediately recognized in current period earnings.

For derivatives designated as fair value hedges, we recognize the gain or loss on the derivative instrument, as well as the offsetting changes in value of the hedged item in earnings in the current period. All derivatives designated and accounted for as fair value hedges are classified in the same category as the item being hedged in the consolidated statements of operations and comprehensive income.

Valuation—When available, quoted market prices or prices obtained through external sources are used to determine a contract’s fair value. For contracts with a delivery location or duration for which quoted market prices are not available, fair value is determined based on pricing models developed primarily from historical and expected correlations with quoted market prices.

Values are adjusted to reflect the credit risk inherent in the transaction as well as the potential impact of liquidating open positions in an orderly manner over a reasonable time period under current conditions. Changes in market prices and management estimates directly affect the estimated fair value of these contracts. Accordingly, it is reasonably possible that such estimates may change in the near term.

Property, Plant and Equipment—Property, plant and equipment are recorded at original cost. Depreciation is computed using the straight-line method over the estimated useful lives of the assets. The costs of maintenance and repairs, which are not significant improvements, are expensed when incurred.

Asset retirement obligations associated with tangible long-lived assets are recorded at fair value in the period in which they are incurred, if a reasonable estimate of fair value can be made, and added to the carrying amount of the associated asset. This additional carrying amount is then depreciated over the life of the asset. The liability increases due to the passage of time based on the time value of money until the obligation is settled. We recognize a liability for conditional asset retirement obligations as soon as the fair value of the liability can be reasonably estimated. A conditional asset retirement obligation is defined as an unconditional legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity.

Investments in Unconsolidated Affiliates—We use the equity method to account for investments in greater than 20% owned affiliates that are not variable interest entities and where we do not have the ability to exercise control, and investments in less than 20% owned affiliates where we have the ability to exercise significant influence.

We evaluate our investments in unconsolidated affiliates for impairment when events or changes in circumstances indicate, in management’s judgment, that the carrying value of such investments may have experienced an other than temporary decline in value. When evidence of loss in value has occurred, management compares the estimated fair value of the investment to the carrying value of the investment to determine whether any impairment has occurred. Management assesses the fair value of our unconsolidated affiliates using

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YEARS ENDED DECEMBER 31, 2007, 2006 AND 2005

commonly accepted techniques, and may use more than one method, including, but not limited to, recent third party comparable sales and discounted cash flow models. If the estimated fair value is less than the carrying value and management considers the decline in value to be other than temporary, the excess of the carrying value over the estimated fair value is recognized in the financial statements as an impairment loss.

Intangible Assets and Goodwill—Intangible assets consist primarily of commodity sales and purchase contracts and relationships, which are amortized on a straight-line basis over the term of the contract or anticipated relationship, ranging from one to 25 years. Goodwill is the cost of an acquisition less the fair value of the net assets of the acquired business.

We evaluate goodwill for impairment annually in the third quarter, and whenever events or changes in circumstances indicate it is more likely than not that the fair value of a reporting unit is less than its carrying amount. Impairment testing of goodwill consists of a two-step process. The first step involves comparing the fair value of the reporting unit, to which goodwill has been allocated, with its carrying amount. If the carrying amount of the reporting unit exceeds its fair value, the second step of the process involves comparing the fair value and carrying value of the goodwill of that reporting unit. If the carrying value of the goodwill of a reporting unit exceeds the fair value of that goodwill, the excess of the carrying value over the fair value is recognized as an impairment loss.

Long-Lived Assets—We evaluate whether the carrying value of long-lived assets, excluding goodwill, has been impaired when circumstances indicate the carrying value of those assets may not be recoverable. The carrying amount is not recoverable if it exceeds the undiscounted sum of cash flows expected to result from the use and eventual disposition of the asset. We consider various factors when determining if these assets should be evaluated for impairment, including but not limited to:

- a significant adverse change in legal factors or business climate;
- a current period operating or cash flow loss combined with a history of operating or cash flow losses, or a projection or forecast that demonstrates continuing losses associated with the use of a long-lived asset;
- an accumulation of costs significantly in excess of the amount originally expected for the acquisition or construction of a long-lived asset;
- significant adverse changes in the extent or manner in which an asset is used, or in its physical condition;
- a significant adverse change in the market value of an asset; and
- a current expectation that, more likely than not, an asset will be sold or otherwise disposed of before the end of its estimated useful life.

If the carrying value is not recoverable, the impairment loss is measured as the excess of the asset’s carrying value over its fair value. Management assesses the fair value of long-lived assets using commonly accepted techniques, and may use more than one method, including, but not limited to, recent third party comparable sales and discounted cash flow models. Significant changes in market conditions resulting from events such as the condition of an asset or a change in management’s intent to utilize the asset would generally require management to reassess the cash flows related to the long-lived assets.

Upon classification as held for sale, a long-lived asset is measured at the lower of its carrying amount or fair value less cost to sell, depreciation is ceased and the asset is separately presented on the consolidated balance sheets.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — Continued
YEARS ENDED DECEMBER 31, 2007, 2006 AND 2005

If an asset held for sale or sold (1) has clearly distinguishable operations and cash flows, generally at the plant level, (2) has direct cash flows of the held for sale or sold component that will be eliminated (from the perspective of the held for sale or sold component), and (3) if we are unable to exert significant influence over the disposed component, then the related results of operations for the current and prior periods, including any related impairments and gains or losses on sales are reflected as income from discontinued operations in the consolidated statements of operations and comprehensive income. If an asset held for sale or sold does not have clearly distinguishable operations and cash flows, impairments and gains or losses on sales are recorded as gain on sale of assets in the consolidated statements of operations and comprehensive income.

Unamortized Debt Premium, Discount and Expense—Premiums, discounts and expenses incurred with the issuance of long-term debt are amortized over the terms of the debt using the effective interest method. These premiums and discounts are recorded on the consolidated balance sheets within long-term debt. These unamortized expenses are recorded on the consolidated balance sheets as other non-current assets.

Distributions—Under the terms of the LLC Agreement, we are required to make quarterly distributions to Spectra Energy and ConocoPhillips based on allocated taxable income. The LLC Agreement provides for taxable income to be allocated in accordance with Internal Revenue Code Section 704(c). This Code Section accounts for the variation between the adjusted tax basis and the fair market value of assets contributed to the joint venture. The distribution is based on the highest taxable income allocated to either member with a minimum of each member's tax, with the other member receiving a proportionate amount to maintain the ownership capital accounts at 50% for both Spectra Energy and ConocoPhillips. Prior to January 2, 2007, the capital accounts were maintained at 50% for both Duke Energy and ConocoPhillips, and prior to July 1, 2005, the capital accounts were maintained at 69.7% for Duke Energy and 30.3% for ConocoPhillips. During the years ended December 31, 2007, 2006 and 2005, we paid distributions of $497 million, $650 million and $389 million, respectively, based on estimated annual taxable income allocated to the members according to their respective ownership percentages at the date the distributions became due.

Our board of directors determines the amount of the quarterly dividend to be paid to Spectra Energy and ConocoPhillips, by considering net income, cash flow or any other criteria deemed appropriate. The LLC Agreement restricts payment of dividends except with the approval of both members. During the years ended December 31, 2007, 2006 and 2005, we paid dividends of $867 million, $801 million and $1,925 million, respectively, to the members. The $1,925 million paid during the year ended December 31, 2005, is comprised of a disproportionate cash distribution of approximately $1,100 million to Duke Energy using the proceeds from the sale of our general partner interest in TEPPCO as part of the 50-50 Transaction, a $245 million proportionate distribution to Duke Energy and ConocoPhillips as part of the 50-50 Transaction, and $580 million in proportionate distributions to Duke Energy and ConocoPhillips, which were allocated in accordance with our partners' respective ownership percentages. The $867 million and $801 million paid during the years ended December 31, 2007 and 2006, are comprised of proportionate distributions to Duke Energy and ConocoPhillips, allocated in accordance with our partners' respective ownership percentages.

DCP Partners considers the payment of a quarterly distribution to the holders of its common units and subordinated units, to the extent DCP Partners has sufficient cash from its operations after establishment of cash reserves and payment of fees and expenses, including payments to its general partner, a wholly-owned subsidiary of ours. There is no guarantee, however, that DCP Partners will pay the minimum quarterly distribution on the units in any quarter. DCP Partners will be prohibited from making any distributions to unitholders if it would cause an event of default, or an event of default exists, under its credit agreement. Our limited partner interest in DCP Partners primarily consists of subordinated units and common units. The subordinated units are entitled to receive the minimum quarterly distribution only after DCP Partners' common unitholders have received the

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minimum quarterly distribution plus any arrearages in the payment of the minimum quarterly distribution from prior quarters. The subordination period will end, and the subordinated units will convert to common units, on a one for one basis, when certain distribution requirements, as defined in DCP Partners' partnership agreement, have been met. The subordination period has an early termination provision that permitted 50% of the subordinated units, or 3,571,428 units, to convert to common units in February 2008 and permits the other 50% of the subordinated units to convert to common units on the second business day following the first quarter distribution in 2009, provided the tests for ending the subordination period contained in DCP Partners' partnership agreement are satisfied. During the years ended December 31, 2007 and 2006, DCP Partners paid distributions of approximately $25 million and $13 million, respectively, to its public unitholders. In addition to our 33.9% limited partnership interests we hold a 1.5% general partnership interest, as well as incentive distribution rights, which entitle us to receive an increasing share of available cash when pre-defined distribution targets are achieved.

Foreign Currency Translation—We translated assets and liabilities of our Canadian operations, where the Canadian dollar was the functional currency, at the period-end exchange rates. Revenues and expenses were translated using average monthly exchange rates during the period, which approximates the exchange rates at the time of each transaction during the period. Foreign currency translation adjustments are included in the consolidated statements of operations and of comprehensive income. In July 2005, as part of the 50-50 Transaction, we distributed to Duke Energy substantially all of our Canadian business. As a result, there were no translation gains or losses in AOCI at December 31, 2007, 2006 and 2005.

Revenue Recognition—We generate the majority of our revenues from natural gas gathering, processing, compression, transportation and storage, and NGL fractionation, transportation, gathering, treating, processing and storage, as well as trading and marketing of natural gas and NGLs. We realize revenues either by selling the residue natural gas and NGLs, or by receiving fees from the producers.

We obtain access to raw natural gas and provide our midstream natural gas services principally under contracts that contain a combination of one or more of the following arrangements.

- *Fee-based arrangements*—Under fee-based arrangements, we receive a fee or fees for one or more of the following services: gathering, compressing, treating, processing, or transporting of natural gas. Our fee-based arrangements include natural gas purchase arrangements pursuant to which we purchase raw natural gas at the wellhead, or other receipt points, at an index related price at the delivery point less a specified amount, generally the same as the fees we would otherwise charge for gathering of raw natural gas from the wellhead location to the delivery point. The revenue we earn is directly related to the volume of natural gas that flows through our systems and is not directly dependent on commodity prices. To the extent a sustained decline in commodity prices results in a decline in volumes, however, our revenues from these arrangements would be reduced.
- *Percent-of-proceeds/index arrangements*—Under percentage-of-proceeds/index arrangements, we generally purchase natural gas from producers at the wellhead, or other receipt points, gather the wellhead natural gas through our gathering system, treat and process the natural gas, and then sell the resulting residue natural gas and NGLs based on index prices from published index market prices. We remit to the producers either an agreed-upon percentage of the actual proceeds that we receive from our sales of the residue natural gas and NGLs, or an agreed-upon percentage of the proceeds based on index related prices for the natural gas and the NGLs, regardless of the actual amount of the sales proceeds we receive. Certain of these arrangements may also result in our returning all or a portion of the residue natural gas and/or the NGLs to the producer, in lieu of returning sales proceeds. Our revenues under percent-of-proceeds/index arrangements correlate directly with the price of natural gas and/or NGLs.

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- *Keep-whole arrangements and wellhead purchase arrangements*—Under the terms of a keep-whole processing contract, we gather raw natural gas from the producer for processing, sell the NGLs and return to the producer residue natural gas with a British thermal unit, or Btu, content equivalent to the Btu content of the raw natural gas gathered. This arrangement keeps the producer whole to the thermal value of the raw natural gas received. Under the terms of a wellhead purchase contract, we purchase raw natural gas from the producer at the wellhead or defined receipt point for processing and then market the resulting NGLs and residue gas at market prices. Under these types of contracts, we are exposed to the "frac spread." The frac spread is the difference between the value of the NGLs extracted from processing and the value of the Btu equivalent of the residue natural gas. We benefit in periods when NGL prices are higher relative to natural gas prices.

Our trading and marketing of natural gas and petroleum products, consists of physical purchases and sales, as well as derivative instruments.

We recognize revenue for sales and services under the four revenue recognition criteria, as follows:

Persuasive evidence of an arrangement exists—Our customary practice is to enter into a written contract, executed by both us and the customer.

Delivery—Delivery is deemed to have occurred at the time custody is transferred, or in the case of fee-based arrangements, when the services are rendered. To the extent we retain product as inventory, delivery occurs when the inventory is subsequently sold and custody is transferred to the third party purchaser.

The fee is fixed or determinable—We negotiate the fee for our services at the outset of our fee-based arrangements. In these arrangements, the fees are nonrefundable. For other arrangements, the amount of revenue, based on contractual terms, is determinable when the sale of the applicable product has been completed upon delivery and transfer of custody.

Collectability is probable—Collectability is evaluated on a customer-by-customer basis. New and existing customers are subject to a credit review process, which evaluates the customers' financial position (for example, cash position and credit rating) and their ability to pay. If collectability is not considered probable at the outset of an arrangement in accordance with our credit review process, revenue is recognized when the fee is collected.

We generally report revenues gross in the consolidated statements of operations and comprehensive income, as we typically act as the principal in these transactions, take custody of the product, and incur the risks and rewards of ownership. Effective April 1, 2006, any new or amended contracts for certain sales and purchases of inventory with the same counterparty, when entered into in contemplation of one another, are reported net as one transaction. We recognize revenues for our NGL and residue gas derivative trading activities net in the consolidated statements of operations and comprehensive income as trading and marketing gains and losses. These activities include mark-to-market gains and losses on energy trading contracts, and the financial or physical settlement of energy trading contracts.

Revenue for goods and services provided but not invoiced is estimated each month and recorded along with related purchases of goods and services used but not invoiced. These estimates are generally based on estimated commodity prices, preliminary throughput measurements and allocations and contract data. There are no material differences between the actual amounts and the estimated amounts of revenues and purchases recorded at December 31, 2007, 2006 and 2005.

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Quantities of natural gas or NGLs over-delivered or under-delivered related to imbalance agreements with customers, producers or pipelines are recorded monthly as other receivables or other payables using current market prices or the weighted average prices of natural gas or NGLs at the plant or system. These balances are settled with deliveries of natural gas or NGLs, or with cash. Included in the consolidated balance sheets as accounts receivable—other as of December 31, 2007 and 2006 were imbalances totaling $48 million and $45 million, respectively. Included in the consolidated balance sheets as accounts payable—other, as of December 31, 2007 and 2006 were imbalances totaling $54 million and $42 million, respectively.

Significant Customers—ConocoPhillips, an affiliated company, was a significant customer in each of the past three years. Sales to ConocoPhillips, including its 50% owned equity method investment, Chevron Phillips Chemical Company LLC, or CP Chem, totaled approximately $2,787 million, $2,677 million, and $2,513 million during 2007, 2006 and 2005, respectively.

Environmental Expenditures—Environmental expenditures are expensed or capitalized as appropriate, depending upon the future economic benefit. Expenditures that relate to an existing condition caused by past operations, and that do not generate current or future revenue, are expensed. Liabilities for these expenditures are recorded on an undiscounted basis when environmental assessments and/or clean-ups are probable and the costs can be reasonably estimated. Environmental liabilities as of December 31, 2007 and 2006, included in the consolidated balance sheets, totaled $6 million in both periods recorded as other current liabilities, and totaled $6 million in both periods recorded as other long-term liabilities.

Stock-Based Compensation—Equity classified stock-based compensation cost is measured at fair value, based on the closing common unit price at grant date, and is recognized as expense over the vesting period. Liability classified stock-based compensation cost is remeasured at each reporting date at fair value, based on the closing common unit price, and is recognized as expense over the requisite service period. Compensation expense for awards with graded vesting provisions is recognized on a straight-line basis over the requisite service period of each separately vesting portion of the award. Awards granted to non-employees for acquiring, or in conjunction with selling goods and services, are measured at the estimated fair value of the goods or services, or the fair value of the award, whichever is more reliably measured.

Through July 1, 2005, we accounted for stock-based compensation by measuring the intrinsic value of an award at the measurement dates. The intrinsic value of an award is the amount by which the quoted market price of the underlying stock exceeds the amount, if any, an employee would be required to pay to acquire the stock. Since the exercise price for all options granted under the plan was equal to the market value of the underlying common stock on the date of grant, no compensation expense has historically been recognized in the accompanying consolidated statements of operations and comprehensive income. Compensation expense for phantom stock awards and other stock awards was recorded from the date of grant over the required vesting period based on the market value of the awards at the date of grant. Compensation expense for stock-based performance awards was recorded over the required vesting period, and adjusted for increases and decreases in market value at each reporting date up to the measurement dates.

Effective January 1, 2006, we adopted the provisions of Statement of Financial Accounting Standard, or SFAS, No. 123(R) (Revised 2004) *"Share-Based Payment,"* or SFAS 123R, which establishes accounting for stock-based awards exchanged for employee and non-employee services. Accordingly, equity classified stock-based compensation cost is measured at grant date, based on the fair value of the award, and is recognized as expense over the requisite service period. Liability classified stock-based compensation cost is remeasured at each reporting date, and is recognized over the requisite service period.

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We elected to adopt the modified prospective application method as provided by SFAS 123R and, accordingly, financial statement amounts for 2005 presented in these consolidated financial statements have not been restated. Compensation expense for awards with graded vesting provisions is recognized on a straight-line basis over the requisite service period of each separately vesting portion of the award.

The following table shows what net income would have been if the fair value recognition provisions of SFAS 123R had been applied to all stock-based compensation awards for the year ended December 31, 2005.

	Year Ended December 31, 2005 (millions)
Net income, as reported	$ 2,170
Add: stock-based compensation expense included in reported net income	3
Deduct: total stock-based compensation expense determined under fair value-based method for all awards	(3)
Pro forma net income	$ 2,170

Accounting for Sales of Units by a Subsidiary—We account for sales of units by a subsidiary by recording a gain or loss on the sale of common equity of a subsidiary equal to the amount of proceeds received in excess of the carrying value of the units sold. As a result, we have deferred approximately $228 million of gain on sale of common units in DCP Partners, which is included in other long-term liabilities in the consolidated balance sheets. This gain is comprised of approximately $36 million related to DCP Partners’ private placement in August 2007, $43 million related to DCP Partners’ private placement in June 2007, and approximately $149 million related to DCP Partners’ initial public offering in December 2005. We will recognize this gain in earnings upon conversion of all of our subordinated units in DCP Partners to common units.

Income Taxes—We are structured as a limited liability company, which is a pass-through entity for U.S. income tax purposes. We own a corporation that files its own federal, foreign and state corporate income tax returns. The income tax expense related to this corporation is included in our income tax expense, along with state, local, franchise and margin taxes of the limited liability company and other subsidiaries. In addition, until July 1, 2005, we had Canadian subsidiaries that were subject to Canadian income taxes.

We follow the asset and liability method of accounting for income taxes. Under the asset and liability method, deferred income taxes are recognized for the tax consequences of temporary differences between the financial statement carrying amounts and the tax basis of the assets and liabilities.

Recent Accounting Pronouncements**—SFAS No. 160, "*****Noncontrolling Interests in Consolidated Financial Statements, an amendment of Accounting Research Bulletin No. 51,*****" or SFAS 160.** In December 2007, the FASB issued SFAS 160, which establishes accounting and reporting standards for ownership interests in subsidiaries held by parties other than the parent, the amount of consolidated net income attributable to the parent and to the noncontrolling interest, changes in a parent’s ownership interest and the valuation of retained noncontrolling equity investments when a subsidiary is deconsolidated. The Statement also establishes reporting requirements that provide sufficient disclosures that clearly identify and distinguish between the interests of the parent and the interests of the noncontrolling owners. SFAS 160 is effective for us on January 1, 2009. Due to the recency of this pronouncement, we have not assessed the impact of SFAS 160 on our consolidated results of operations, cash flows or financial position.

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SFAS No. 141(R) "*Business Combinations (revised 2007)*," or SFAS 141(R). In December, 2007, the FASB issued SFAS 141(R), which requires the acquiring entity in a business combination to recognize all (and only) the assets acquired and liabilities assumed in the transaction; establishes the acquisition-date fair value as the measurement objective for all assets acquired and liabilities assumed; and requires the acquirer to disclose to investors and other users all of the information they need to evaluate and understand the nature and financial effect of the business combination. SFAS 141(R) is effective for us on January 1, 2009. As this standard will be applied prospectively upon adoption, we will account for all transactions with closing dates subsequent to the adoption date in accordance with the provisions of the standard.

SFAS No. 159 "*The Fair Value Option for Financial Assets and Financial Liabilities—including an amendment of FAS 115*," or SFAS 159. In February 2007, the FASB issued SFAS 159, which allows entities to choose, at specified election dates, to measure eligible financial assets and liabilities at fair value that are not otherwise required to be measured at fair value. If a company elects the fair value option for an eligible item, changes in that item's fair value in subsequent reporting periods must be recognized in current earnings. SFAS 159 also establishes presentation and disclosure requirements designed to draw comparison between entities that elect different measurement attributes for similar assets and liabilities. SFAS 159 is effective for us on January 1, 2008. We have not elected the fair value option relative to any of our financial assets and liabilities which are not otherwise required to be measured at fair value by other accounting standards. Therefore, there is no effect of adoption reflected in our consolidated results of operations, cash flows or financial position.

SFAS No. 157 *"Fair Value Measurements,"* or SFAS 157. In September 2006, the FASB issued SFAS 157, which provides a single definition of fair value, together with a framework for measuring it, and requires additional disclosure about the use of fair value to measure assets and liabilities. The standard establishes a framework for measuring fair value and expands the disclosure requirements surrounding assumptions made in the measurement of fair value.

The adoption of this standard will result in us making slight changes to our valuation methodologies to incorporate the marketplace participant view as prescribed by SFAS 157. Such changes will include, but will not be limited to, changes in valuation policies to reflect an exit price methodology, the effect of considering our own non-performance risk on the valuation of liabilities, and the effect of any change in our credit rating or standing. As a result of adopting SFAS 157, we estimate a cumulative effect transition adjustment of an after-tax increase to members' equity of approximately $8 million. This transition adjustment will directly affect the beginning balance of members' equity.

Pursuant to FASB Financial Staff Position 157-2, the FASB issued a partial deferral of the implementation of SFAS 157 as it relates to all non-financial assets and liabilities where fair value is the required measurement attribute by other accounting standards. While, we have adopted SFAS 157 for all financial assets and liabilities (primarily as a result of derivative trading activity) effective January 1, 2008, we have not assessed the impact that the adoption of SFAS 157 will have on our non-financial assets and liabilities.

FASB Interpretation No. 48 *"Accounting for Uncertainty in Income Taxes—An Interpretation of FASB Statement 109,"* or FIN 48. In July 2006, the FASB issued FIN 48, which clarifies the accounting for uncertainty in income taxes recognized in financial statements in accordance with FASB Statement No. 109, "*Accounting for Income Taxes."* FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. The provisions of FIN 48 were effective for us on January 1, 2007, and the adoption of FIN 48 did not have a material impact on our consolidated results of operations, cash flows or financial position.

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2. Acquisitions and Dispositions

Acquisitions

Acquisition of Various Gathering, Pipeline and Compression Assets—On August 29, 2007, we acquired the stock of Momentum Energy Group, Inc., or MEG, for approximately $635 million plus closing adjustments of approximately $11 million. The results of MEG's operations have been included in the consolidated financial statements since that date. As a result of the acquisition, we expanded our operations into the Fort Worth, Piceance and Powder River producing basins, thus diversifying our business into new areas. We funded our portion of this acquisition with a 364-day bridge loan for $450 million, which was paid off in September 2007 with proceeds from the issuance of the $450 million principal amount of 6.75% Senior Notes, as well as cash on hand. See further discussion of this transaction in the Contributions to DCP Partners section below.

Under the purchase method of accounting, the assets and liabilities of MEG were recorded at their respective fair values as of the date of the acquisition, and we recorded goodwill of approximately $135 million. The goodwill amount recognized relates primarily to projected growth in the Fort Worth and Piceance producing basins due to significant natural gas reserves and high level of drilling activity. We expect all of the goodwill to be tax deductible. The values of certain assets and liabilities are preliminary, and are subject to adjustment as additional information is obtained. When finalized, material adjustments to goodwill may result.

The purchase price allocation is as follows (millions):

Cash	$ 42
Receivables	23
Other assets	2
Property, plant and equipment	278
Intangible assets	254
Goodwill	135
Payables	(18)
Other liabilities	(27)
Current debt	(20)
Minority interest	(23)
Total allocation of purchase price	$646

In May 2007, DCP Partners acquired certain gathering and compression assets located in southern Oklahoma, as well as related commodity purchase contracts, from Anadarko Petroleum Corporation for approximately $181 million.

In the fourth quarter of 2005, we entered into an agreement to purchase certain pipeline and compressor station assets in Kansas, Oklahoma and Texas for approximately $50 million, which are regulated by the Federal Energy Regulatory Commission, or FERC. We did not receive regulatory approval from the FERC to purchase the assets as non-jurisdictional gathering, but we have filed with the FERC for a certificate to operate as an interstate pipeline. This acquisition is expected to close in 2008.

Acquisition of Additional Equity Interests—In December 2006, we acquired an additional one-third interest in Main Pass Oil Gathering Company, or Main Pass, for approximately $30 million. We now own two-thirds of Main Pass with one other partner. Main Pass is a joint venture whose primary operation is a crude oil gathering

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pipeline system in the Gulf of Mexico. Since Main Pass is not a variable interest entity, and we do not have the ability to exercise control, we continue to account for Main Pass under the equity method.

In November 2006, we purchased the remaining 16% minority interest in Dauphin Island Gathering Partners, or DIGP, for $7 million. DIGP was owned 84% by us prior to this transaction, and subsequent to this transaction, is owned 100% by us. DIGP owns gathering and transmission assets in the Gulf Coast.

In December 2005, we purchased an additional 6.67% interest in Discovery Producer Services LLC, or Discovery, from Williams Energy, LLC for a purchase price of $13 million. Discovery is an unconsolidated affiliate, which, prior to this transaction, was 33.33% owned by us, and subsequent to this transaction is 40% owned by us. Discovery owns and operates an interstate pipeline, a condensate handling facility, a cryogenic gas processing plant and other gathering assets in deepwater offshore Louisiana.

Dispositions

Disposition of Various Gathering, Transmission and Processing Assets—During the first quarter of 2006, we sold assets totaling $57 million, for proceeds of $85 million, and we recognized a gain of $28 million.

In August 2005, we sold certain gas gathering facilities in Kansas and Oklahoma for a sales price of approximately $11 million. No gain or loss was recognized.

In February 2005, we exchanged certain processing plant assets in Wyoming for certain gathering assets and related gathering contracts in Oklahoma of equivalent fair value.

In February 2005, we sold certain gathering, compression, fractionation, processing plant and transportation assets in Wyoming for approximately $28 million.

Disposition of Equity Interests—In February 2005, we sold our general partner interest in TEPPCO to Enterprise GP Holdings L.P., an unrelated third party, for $1,100 million in cash and recognized a gain of $1,137 million. The cash proceeds from this transaction were received in February 2005 and loaned to Duke Energy and ConocoPhillips in amounts equal to their ownership percentages in the Company at that time. The loans were made under the terms of revolving credit facilities established in February 2005 with Duke Capital LLC, an affiliate of Duke Energy, and ConocoPhillips in the amounts of $767 million and $333 million, respectively. ConocoPhillips repaid its outstanding borrowings in full in March 2005. Duke Capital, LLC repaid its outstanding borrowings in full in July 2005.

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Distribution of Canadian Business to Duke Energy—In July 2005, as part of the 50-50 Transaction, we distributed to Duke Energy substantially all of our Canadian business. These assets comprised a component of the Company for purposes of reporting discontinued operations. The results of operations and cash flows related to these assets have been reclassified to discontinued operations for all periods presented. The following is a summary of the net assets distributed to Duke Energy on the closing date of July 1, 2005 (millions):

Assets:	
Cash	$ 44
Accounts receivable	18
Other assets	1
Property, plant and equipment, net	291
Goodwill	18
Total assets	$372
Liabilities:	
Accounts payable	$ 11
Other current liabilities	4
Current and long-term debt	1
Deferred income taxes	20
Other long-term liabilities	12
Total liabilities	$ 48
Net assets of Canadian business distributed to Duke Energy	$324

We routinely sell assets that comprise a component of the Company, and are recorded as discontinued operations, but are not individually significant. The results of operations and cash flows related to these assets have been reclassified to discontinued operations for all periods presented.

There were no assets accounted for as discontinued operations for the years ended December 31, 2007 or 2006. The following table sets forth selected financial information associated with assets accounted for as discontinued operations.

	For the Year Ended December 31, 2005 (millions)
Operating revenues	$ 35
Pre-tax operating income	$ 4
Income tax expense	(1)
Income from discontinued operations	$ 3

Contributions to DCP Partners

MEG—Concurrent with our acquisition of the stock of MEG in August 2007, DCP Partners acquired certain subsidiaries of MEG from us for $166 million plus post-closing purchase price adjustments of approximately $9 million. These subsidiaries of MEG own assets in the Piceance Basin, including a 70% operated interest in the

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Collbran Valley Gas Gathering system joint venture in western Colorado, and assets in the Powder River Basin, including the Douglas gas gathering system in Wyoming. DCP Partners financed this transaction with $120 million of revolver and term loan borrowings under DCP Partners' Amended Credit Agreement, the issuance of common units through a private placement with certain institutional inventors and cash on hand. In August 2007, DCP Partners issued 2,380,952 common limited partner units in a private placement, pursuant to a common unit purchase agreement with private owners of MEG or affiliates of such owners, at $42.00 per unit, or approximately $100 million in the aggregate. As a result of this transaction, the omnibus agreement with DCP Partners was amended to increase the annual fee payable to us by DCP Partners by $2 million for incremental general and administrative expenses. We will continue to operate these assets and these assets will continue to be included in our financial statements, through the consolidation of DCP Partners.

DCP East Texas Holdings, LLC and Discovery Producer Services LLC—In July 2007, we contributed to DCP Partners our 25% limited liability company interest in DCP East Texas Holdings, LLC, or East Texas, our 40% limited liability company interest in Discovery and a derivative instrument, for aggregate consideration of $244 million in cash, including $1 million for net working capital and other adjustments, $27 million in common units and $1 million in general partner equivalent units. We own the remaining 75% limited liability company interest in East Texas, while third parties still own the other 60% limited liability interest in Discovery. DCP Partners financed the cash portion of this transaction with borrowings under its existing credit facility. We will continue to operate East Texas and both of these assets will continue to be included in our financial statements, through the consolidation of DCP Partners.

Wholesale Propane Logistics Business—In November 2006, we contributed our wholesale propane logistics business to DCP Partners for consideration of approximately $83 million, including $77 million in cash ($10 million of which was paid in January 2007 upon completion of construction of a new propane terminal), and $6 million in Class C units. DCP Partners financed this transaction with its existing credit facility and the issuance of Class C units, which were subsequently converted to common units on July 2, 2007. As a result of this transaction, the omnibus agreement with DCP Partners was amended to increase the annual fee payable to us by DCP Partners by $2 million for incremental general and administrative expenses. We will continue to operate these assets and these assets will continue to be included in our financial statements, through the consolidation of DCP Partners.

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3. Agreements and Transactions with Affiliates

The following table summarizes the transactions with affiliates:

	For the Years Ended, December 31,		
	2007	2006	2005
		(millions)	
Spectra Energy:			
Sales of natural gas and petroleum products to affiliates	$ 2	$ —	$ —
Transportation, storage and processing	$ 4	$ —	$ —
Purchases of natural gas and petroleum products from affiliates	$ 123	$ —	$ —
Operating and general and administrative expenses	$ 13	$ —	$ —
Duke Energy:			
Sales of natural gas and petroleum products to affiliates	$ —	$ 41	$ 109
Transportation, storage and processing	$ —	$ 18	$ 2
Purchases of natural gas and petroleum products from affiliates	$ —	$ 137	$ 130
Operating and general and administrative expenses	$ —	$ 30	$ 44
Interest income	$ —	$ —	$ 8
ConocoPhillips (a):			
Sales of natural gas and petroleum products to affiliates	$ 2,787	$ 2,677	$ 2,513
Transportation, storage and processing	$ 17	$ 12	$ 11
Purchases of natural gas and petroleum products from affiliates	$ 489	$ 492	$ 556
General and administrative expenses	$ 2	$ 5	$ —
Unconsolidated affiliates:			
Sales of natural gas and petroleum products to affiliates	$ 95	$ 95	$ 163
Transportation, storage and processing	$ 23	$ 20	$ 20
Purchases of natural gas and petroleum products from affiliates	$ 169	$ 160	$ 144

(a) Includes ConocoPhillips' 50% owned equity method investment, Chevron Phillips Chemical Company LLC

Spectra Energy

Commodity Transactions—We sell a portion of our residue gas and NGLs to, purchase raw natural gas and other petroleum products from, and provide gathering and transportation services to Spectra Energy and their subsidiaries. Management anticipates continuing to purchase and sell commodities and provide services to Spectra Energy in the ordinary course of business.

Included in the consolidated balance sheets in other non-current assets—affiliates as of December 31, 2007 and 2006, are insurance recovery receivables of $27 million and $47 million, respectively, and included in accounts receivable—affiliates as of December 31, 2007 and 2006, are other receivables of $2 million and $8 million, respectively. Prior to January 2, 2007, these receivables were from an insurance provider that is a subsidiary of Duke Energy. In connection with the Spectra spin, Spectra Energy is responsible for these insurance liabilities. During the years ended December 31, 2007, 2006 and 2005, we recorded hurricane related business interruption insurance recoveries of $4 million, $1 million and $3 million, respectively, included in the consolidated statements of operations and comprehensive income as transportation, storage and processing.

Duke Energy

In connection with the Spectra spin, Duke Energy is not considered a related party for reporting periods after January 2, 2007.

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Commodity Transactions—In 2006, we sold a portion of our residue gas and NGLs to, purchased raw natural gas and other petroleum products from, and provided gathering and transportation services to Duke Energy and their subsidiaries.

Services Agreement—Under a services agreement, Duke Energy and certain of its subsidiaries provided us with various staff and support services, including information technology products and services, payroll, employee benefits, property taxes, media relations, printing and records management. Additionally, we used other Duke Energy services subject to hourly rates, including legal, insurance, internal audit, tax planning, human resources and security departments.

In connection with the Spectra spin, as of December 31, 2007, our corporate operations, Spectra Energy, or third party service providers have assumed responsibility for all services previously provided to us by Duke Energy.

In the fourth quarter of 2006, an insurance provider that is a subsidiary of Duke Energy agreed to settle an insurance claim, related to a damaged underground storage facility, for approximately $21 million. We had recorded a receivable in 2005 related to this claim for approximately $4 million. Upon receipt of the cash in December 2006, we relieved the receivable and recorded business interruption insurance recoveries of approximately $16 million, included in the consolidated statements of operations and comprehensive income as transportation, storage and processing.

ConocoPhillips

Long-term NGLs Purchases Contract and Transactions—We sell a portion of our residue gas and NGLs to ConocoPhillips and its subsidiaries, including Chevron Phillips Chemical Company LLC, or CP Chem, a 50% equity investment of ConocoPhillips. In addition, we purchase raw natural gas from ConocoPhillips. Under the NGL Output Purchase and Sale Agreements, or the NGL Agreements, with ConocoPhillips and CP Chem, ConocoPhillips and CP Chem have the right to purchase at index-based prices substantially all NGLs produced by our various processing plants located in the Mid-Continent and Permian Basin regions, and the Austin Chalk area, which include approximately 40% of our total NGL production. The NGL Agreements also grant ConocoPhillips and CP Chem the right to purchase at index-based prices certain quantities of NGLs produced at processing plants that are acquired and/or constructed by us in the future in various counties in the Mid-Continent and Permian Basin regions, and the Austin Chalk area. The primary terms of the agreements are effective until January 1, 2015. We anticipate continuing to purchase and sell these commodities and provide these services to ConocoPhillips and CP Chem in the ordinary course of business.

Transactions with other unconsolidated affiliates

We sell a portion of our residue gas and NGLs to, purchase raw natural gas and other petroleum products from, and provide gathering and transportation services to, unconsolidated affiliates. We anticipate continuing to purchase and sell commodities and provide services to unconsolidated affiliates in the ordinary course of business.

In February 2005, we sold our general partner interest in TEPPCO to Enterprise GP Holdings L.P., an unrelated third party, for $1,100 million in cash and recognized a gain of $1,137 million. The cash proceeds from this transaction were received in February 2005 and loaned to Duke Energy and ConocoPhillips in amounts equal to their ownership percentages in the Company at that time. The loans were made under the terms of revolving

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credit facilities established in February 2005 with Duke Capital LLC, an affiliate of Duke Energy, and ConocoPhillips in the amounts of $767 million and $333 million, respectively. ConocoPhillips repaid their outstanding borrowings in full in March 2005. Duke Capital LLC repaid their outstanding borrowings in full in July 2005.

Estimates related to affiliates

Revenue for goods and services provided but not invoiced to affiliates is estimated each month and recorded along with related purchases of goods and services used but not invoiced. These estimates are generally based on estimated commodity prices, preliminary throughput measurements and allocations and contract data. Actual invoices for the current month are issued in the following month and differences from estimated amounts are recorded. There are no material differences from the actual amounts invoiced subsequent to quarter end relating to estimated revenues and purchases recorded at December 31, 2007, 2006 and 2005.

4. Inventories

Inventories were as follows:

	December 31, 2007	December 31, 2006
	(millions)	
Natural gas held for resale	$ 39	$ 34
NGLs	78	53
Total inventories	$ 117	$ 87

5. Property, Plant and Equipment

Property, plant and equipment by classification was as follows:

	Depreciable Life	December 31, 2007	December 31, 2006
		(millions)	
Gathering	15 - 30 years	$ 3,233	$ 2,641
Processing	25 - 30 years	2,030	1,904
Transportation	25 - 30 years	1,224	1,217
Underground storage	20 - 50 years	121	119
General plant	3 - 5 years	153	146
Construction work in progress		347	203
		7,108	6,230
Accumulated depreciation		(2,665)	(2,361)
Property, plant and equipment, net		$ 4,443	$ 3,869

Depreciation expense for the years ended December 31, 2007, 2006 and 2005 was $304 million, $275 million and $278 million, respectively. Interest capitalized on construction projects in 2007, 2006 and 2005, was approximately $4 million, $3 million and $2 million, respectively. At December 31, 2007 we had non-cancelable purchase obligations of approximately $9 million for capital projects to be completed in 2008.

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6. Goodwill and Intangible Assets

The changes in carrying amount of goodwill are as follows:

	December 31, 2007	December 31, 2006
	(millions)	
Goodwill, beginning of period	$ 421	$ 421
Goodwill acquired	135	—
Goodwill, end of period	$ 556	$ 421

The increase in goodwill during 2007 consists of the amount that we recognized in connection with our acquisition of MEG.

We perform an annual goodwill impairment test, and update the test during interim periods if events or circumstances occur that would more likely than not reduce the fair value of a reporting unit below its carrying amount. We use a discounted cash flow analysis supported by market valuation multiples to perform the assessment. Key assumptions in the analysis include the use of an appropriate discount rate, estimated future cash flows and an estimated run rate of general and administrative costs. In estimating cash flows, we incorporate current market information, as well as historical and other factors, into our forecasted commodity prices. Our annual goodwill impairment test, as of August 31, 2007, and our interim goodwill impairment test in conjunction with the distribution of substantially all of our Canadian business to Duke Energy in conjunction with the 50-50 Transaction, in July 2005, both indicated that our reporting units' fair values exceed their carrying or book values. Accordingly, no impairment of goodwill is indicated.

Intangible assets consist primarily of commodity sales and purchase contracts and relationships. The gross carrying amount and accumulated amortization for intangible assets are as follows:

	December 31, 2007	December 31, 2006
	(millions)	
Gross carrying amount	$398	$132
Accumulated amortization	(86)	(74)
Intangible assets, net	$312	$ 58

Intangible assets increased as a result of the Southern Oklahoma and MEG acquisitions, through which $12 million and $254 million, respectively, of intangible assets were acquired. During the years ended December 31, 2007, 2006 and 2005 we recorded amortization expense of $12 million, $9 million, and $9 million, respectively. The remaining amortization periods range from less than one year to 25 years, with a weighted average remaining period of approximately 21 years.

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Estimated amortization for these contracts for the next five years and thereafter is as follows as of December 31, 2007:

	Estimated Amortization (millions)
2008	$ 21
2009	20
2010	19
2011	18
2012	18
Thereafter	216
Total	$312

7. Investments in Unconsolidated Affiliates

We have investments in the following unconsolidated affiliates accounted for using the equity method:

	2007 Ownership	December 31, 2007	December 31, 2006
		(millions)	
Discovery Producer Services LLC	40.00%	$ 118	$ 114
Main Pass Oil Gathering Company	66.67%	43	47
Mont Belvieu I	20.00%	12	11
Sycamore Gas System General Partnership	48.45%	11	12
Tri-States NGL Pipeline, LLC	16.67%	9	9
Black Lake Pipe Line Company	50.00%	7	6
Other unconsolidated affiliates	Various	4	5
Total investments in unconsolidated affiliates		$ 204	$ 204

Discovery Producer Services LLC—Discovery operates a 600 MMcf/d cryogenic natural gas processing plant near Larose, Louisiana, a natural gas liquids fractionator plant near Paradis, Louisiana with a design capacity of 600 MMcf/d and approximately 173 miles of pipe, and several onshore laterals expanding their presence in the Gulf. In December 2005, we acquired an additional 6.67% interest in Discovery from Williams Energy, LLC for a purchase price of $13 million, bringing our total ownership to 40%. The deficit between the carrying amount of the investment and the underlying equity of Discovery of $44 million and $49 million at December 31, 2007 and 2006, respectively, is associated with, and is being depreciated over the life of, the underlying long-lived assets of Discovery.

Main Pass Oil Gathering Company—In December 2006, we acquired an additional 33.33% interest in Main Pass, a joint venture whose primary operation is a crude oil gathering pipeline system in the Main Pass East and Viosca Knoll Block areas in the Gulf of Mexico. We now own 66.67% of Main Pass with one other partner. Since Main Pass is not a variable interest entity, and we do not have the ability to exercise control, we continue to account for Main Pass under the equity method. The excess of the carrying amount of the investment over the underlying equity of Main Pass of $12 million at both December 31, 2007 and 2006, is associated with, and is being depreciated over the life of, the underlying long-lived assets of Main Pass.

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Mont Belvieu I—Mont Belvieu I owns a 150 MBbl/d fractionation facility in the Mont Belvieu, Texas Market Center. The deficit between the carrying amount of the investment and the underlying equity of Mont Belvieu I of $10 million and $11 million at December 31, 2007 and 2006, respectively, is associated with, and is being depreciated over the life of, the underlying long-lived assets of Mont Belvieu I.

Sycamore Gas System General Partnership—Sycamore Gas System General Partnership, or Sycamore, is a partnership formed for the purpose of constructing, owning and operating a gas gathering and compression system in Carter County, Oklahoma. The excess of the carrying amount of the investment over the underlying equity of Sycamore of $7 million and $9 million at December 31, 2007 and 2006, respectively, is associated with, and is being depreciated over the life of, the underlying long-lived assets of Sycamore.

Tri-States NGL Pipeline, LLC—Tri-States NGL Pipeline, LLC, or Tri-States, owns 169 miles of NGL pipeline, extending from a point near Mobile Bay, Alabama to a point near Kenner, Louisiana. The deficit between the carrying amount of the investment and the underlying equity of Tri-States of $3 million at both December 31, 2007 and 2006 is associated with, and is being depreciated over the life of, the underlying long-lived assets of Tri-States. We own less than 20% interest in this Partnership, however, we exercise significant influence, therefore, this investment is accounted for under the equity method of accounting.

Black Lake Pipe Line Company—Black Lake Pipe Line Company, or Black Lake, owns a 317 mile long NGL pipeline, with a current capacity of approximately 40 MBbl/d. The pipeline receives NGLs from a number of gas plants in Louisiana and Texas. The NGLs are transported to Mont Belvieu fractionators. The deficit between the carrying amount of the investment and the underlying equity of Black Lake of $7 million at both December 31, 2007 and 2006, is associated with, and is being depreciated over the life of, the underlying long-lived assets of Black Lake.

TEPPCO Partners, L.P.—In February 2005, we sold our general partner interest in TEPPCO to Enterprise GP Holdings L.P., an unrelated third party, for $1,100 million in cash and recognized a gain of $1,137 million.

Equity in earnings of unconsolidated affiliates amounted to the following:

	For the Years Ended December 31,		
	2007	2006	2005
		(millions)	
Discovery Producer Services LLC	$ 24	$ 17	$ 11
Main Pass Oil Gathering Company	1	3	3
Mont Belvieu I	1	(1)	(1)
Sycamore Gas System General Partnership	(1)	(1)	(1)
Tri-States NGL Pipeline, LLC	1	1	1
Black Lake Pipe Line Company	1	—	—
TEPPCO Partners, L.P.	—	—	8
Other unconsolidated affiliates	2	1	1
Total equity in earnings of unconsolidated affiliates	$ 29	$ 20	$ 22

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The following summarizes combined financial information of unconsolidated affiliates:

	For the Years Ended December 31,		
	2007	2006	2005
		(millions)	
Income Statement:			
Operating revenues	$354	$322	$328
Operating expenses	$297	$287	$312
Net income	$ 61	$ 42	$ 18

	December 31,	
	2007	2006
	(millions)	
Balance sheet:		
Current assets	$123	$115
Non-current assets	638	724
Current liabilities	(49)	(61)
Non-current liabilities	(19)	(7)
Net assets	$693	$771

8. Estimated Fair Value of Financial Instruments

We have determined the following fair value amounts using available market information and appropriate valuation methodologies. Considerable judgment is required, however, in interpreting market data to develop the estimates of fair value. Accordingly, the estimates presented herein are not necessarily indicative of the amounts that we could realize in a current market exchange. The use of different market assumptions and/or estimation methods may have a material effect on the estimated fair value amounts.

	December 31, 2007		December 31, 2006	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
		(millions)		
Short-term investments	$ 9	$ 9	$ 437	$ 437
Restricted investments	$ 101	$ 101	$ 102	$ 102
Accounts receivable	$ 1,688	$ 1,688	$ 1,272	$ 1,272
Accounts payable	$ 1,675	$ 1,675	$ 1,624	$ 1,624
Net unrealized (losses) and gains on mark-to-market and hedging instruments	$ (97)	$ (97)	$ 22	$ 22
Long-term debt	$ 2,930	$ 3,030	$ 2,115	$ 2,258

The fair value of short-term investments, restricted investments, accounts receivable and accounts payable are not materially different from their carrying amounts because of the short-term nature of these instruments or the stated rates approximating market rates. Unrealized gains and unrealized losses on mark-to-market and hedging instruments are carried at fair value.

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The estimated fair values of current debt, including current maturities of long-term debt, and long-term debt, with the exception of DCP Partners' long-term debt, are determined by prices obtained from market quotes. The carrying value of DCP Partners' long-term debt approximates fair value, as the interest rate is variable and reflects current market conditions.

9. Asset Retirement Obligations

Our asset retirement obligations relate primarily to the retirement of various gathering pipelines and processing facilities, obligations related to right-of-way easement agreements, and contractual leases for land use. We recognize the fair value of a liability for an asset retirement obligation in the period in which it is incurred, if a reasonable estimate of fair value can be made. The fair value of the liability is added to the carrying amount of the associated asset. This additional carrying amount is then depreciated over the life of the asset. The liability increases due to the passage of time based on the time value of money until the obligation is settled.

We identified various assets as having an indeterminate life, for which there is no requirement to establish a fair value for future retirement obligations associated with such assets. These assets include certain pipelines, gathering systems and processing facilities. A liability for these asset retirement obligations will be recorded only if and when a future retirement obligation with a determinable life is identified. These assets have an indeterminate life because they are owned and will operate for an indeterminate future period when properly maintained. Additionally, if the portion of an owned plant containing asbestos were to be modified or dismantled, we would be legally required to remove the asbestos. We currently have no plans to take actions that would require the removal of the asbestos in these assets. Accordingly, the fair value of the asset retirement obligation related to this asbestos cannot be estimated and no obligation has been recorded.

The asset retirement obligation is adjusted each quarter for any liabilities incurred or settled during the period, accretion expense and any revisions made to the estimated cash flows. The following table summarizes changes in the asset retirement obligation, included in other long-term liabilities in the consolidated balance sheets:

	December 31, 2007	December 31, 2006
	(millions)	
Balance, beginning of period	$ 52	$ 50
Accretion expense	4	3
Liabilities incurred	4	—
Liabilities settled	—	(1)
Other	(1)	—
Balance, end of period	$ 59	$ 52

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10. Financing

Long-term debt was as follows:

	December 31, 2007	December 31, 2006
	(millions)	
Debt securities:		
Issued August 2000, interest at 7.875% payable semiannually, due August 2010	$ 800	$ 800
Issued January 2001, interest at 6.875% payable semiannually, due February 2011	250	250
Issued October 2005, interest at 5.375% payable semiannually, due October 2015	200	200
Issued August 2000, interest at 8.125% payable semiannually, due August 2030	300	300
Issued October 2006, interest at 6.450% payable semiannually, due November 2036	300	300
Issued September 2007, interest at 6.750% payable semiannually, due September 2037	450	—
DCP Partners' credit facility revolver, weighted-average interest rate of 5.47% and 5.86%, respectively, due June 2012(a)	530	168
DCP Partners' credit facility term loan, interest rate of 5.05% and 5.47%, respectively, due June 2012	100	100
Fair value adjustments related to interest rate swap fair value hedges(b)	8	4
Unamortized discount	(8)	(7)
Long-term debt	$2,930	$2,115

(a) $425 million of debt has been swapped to a fixed rate obligation.
(b) $100 million of debt has been swapped to a floating rate obligation.

Debt Securities—In September 2007, we issued $450 million principal amount of 6.75% Senior Notes due 2037, or the 6.75% Notes, for proceeds of approximately $444 million, net of related offering costs. The 6.75% Notes mature and become due and payable on September 15, 2037. We will pay interest semiannually on March 15 and September 15 of each year, commencing March 15, 2008. The proceeds of this offering were used to pay off the 364-Day Bridge Loan described below.

In October 2006, we issued $300 million principal amount of 6.45% Senior Notes due 2036, or the 6.45% Notes, for proceeds of approximately $297 million, net of related offering costs. The 6.45% Notes mature and become due and payable on November 3, 2036. We will pay interest semiannually on May 3 and November 3 of each year, commencing May 3, 2007.

In October 2005, we issued $200 million principal amount of 5.375% Senior Notes Due 2015, or 5.375% Notes, for proceeds of $197 million (net of related offering costs). The 5.375% Notes mature on October 15, 2015. We pay interest semiannually on April 15 and October 15 of each year, commencing April 15, 2006. The proceeds from this offering were used to repay the August 2005 term loan facility discussed below.

In August 2005, we repaid the $600 million 7.5% Notes that were due on August 16, 2005. We repaid a portion of this debt with available cash and proceeds from the issuance of commercial paper, and refinanced a portion of this debt with the August 2005 term loan facility discussed below.

The debt securities mature and become payable on the respective due dates, and are not subject to any sinking fund provisions. Interest is payable semiannually. The debt securities are unsecured and are redeemable at our option.

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Credit Facilities with Financial Institutions—We have a $450 million revolving credit facility, or the Facility, which is used to support our commercial paper program, and for working capital and other general corporate purposes. In October 2006, we amended the Facility to modify the change of control provisions to allow for the Spectra spin, to extend the maturity to April 29, 2012, to amend the pricing, to remove the interest coverage covenant and to incorporate other minor revisions. Any outstanding borrowings under the Facility at maturity may, at our option, be converted to an unsecured one-year term loan. The Facility requires us to maintain at all times a debt to total capitalization ratio of less than or equal to 60%. Draws on the Facility bear interest at a rate equal to, at our option and based on our current debt rating, either (1) LIBOR plus 0.23% per year for the initial 50% usage or LIBOR plus 0.28% per year if usage is greater than 50% or (2) the higher of (a) the Wachovia Bank prime rate per year and (b) the Federal Funds rate plus 0.5% per year. The Facility incurs an annual facility fee of 0.07% based on our credit rating on the drawn and undrawn portions. The Facility may be used for letters of credit. As of December 31, 2007 and 2006, there were no borrowings or commercial paper outstanding, and there were approximately $5 million in letters of credit outstanding for both periods.

In August 2005, we entered into a credit agreement, or the Term Loan Facility, where we made a one-time request to borrow $200 million in the form of a term loan. We used this Term Loan Facility to repay a portion of our $600 million 7.5% Notes that matured on August 16, 2005. The Term Loan Facility was repaid in October 2005 with proceeds from the 5.375% Notes.

On June 21, 2007, DCP Partners entered into the Amended and Restated Credit Agreement, or DCP Partners' Amended Credit Agreement, that replaced their existing credit agreement, or DCP Partners' Credit Agreement, which consists of a $600 million revolving credit facility and a $250 million term loan facility. At December 31, 2007 and 2006, DCP Partners had less than $1 million of letters of credit outstanding. Outstanding balances under the term loan facility are fully collateralized by investments in high-grade securities, which are classified as restricted investments in the accompanying consolidated balance sheet as of December 31, 2007 and December 31, 2006.

Under DCP Partners' Amended Credit Agreement, indebtedness under the revolving credit facility bears interest at either: (1) the higher of Wachovia Bank's prime rate or the federal funds rate plus 0.50%; or (2) LIBOR plus an applicable margin, which ranges from 0.23% to 0.575% dependent upon the leverage level or credit rating. The revolving credit facility incurs an annual facility fee of 0.07% to 0.175% depending on the applicable leverage level or debt rating. This fee is paid on drawn and undrawn portions of the revolving credit facility. The term loan facility bears interest at a rate equal to; (1) LIBOR plus 0.10%; or (2) the higher of Wachovia Bank's prime rate or the federal funds rate plus 0.50%.

DCP Partners' Amended Credit Agreement requires DCP Partners to maintain a leverage ratio (the ratio of consolidated indebtedness to consolidated EBITDA, in each case as is defined by DCP Partners' Amended Credit Agreement) of not more than 5.0 to 1.0, and on a temporary basis for not more than three consecutive quarters (including the quarter in which such acquisition is consummated) following the consummation of asset acquisitions in the midstream energy business of not more than 5.50 to 1.0. DCP Partners' Amended Credit Agreement also requires DCP Partners to maintain an interest coverage ratio (the ratio of consolidated EBITDA to consolidated interest expense, in each case as is defined by DCP Partners' Amended Credit Agreement) of equal or greater than 2.5 to 1.0 determined as of the last day of each quarter for the four-quarter period ending on the date of determination.

Bridge Loans

In August 2007, we entered into a 364-day bridge loan, or the 364-Day Bridge Loan, which provided for borrowings of up to $450 million, and had terms and conditions substantially similar to those of our Facility. We borrowed $450 million to fund a portion of the acquisition of the stock of MEG, and then paid it off in September with proceeds from the issuance of the 6.75% Notes.

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In May 2007, DCP Partners entered into a two-month bridge loan, or the Two-Month Bridge Loan, which provided for borrowings up to $100 million, and had terms and conditions substantially similar to those of DCP Partners' Credit Agreement. In conjunction with DCP Partners entering into the Two-Month Bridge Loan, DCP Partners' Credit Agreement was amended to provide for additional unsecured indebtedness, of an amount not to exceed $100 million, which was due and payable no later than August 9, 2007. DCP Partners used borrowings of $88 million from the Two-Month Bridge Loan to partially fund the acquisition of assets from Anadarko. The remaining $12 million available for borrowing on the Two-Month Bridge Loan was not utilized. DCP Partners used a portion of the net proceeds of a private placement of limited partner units to extinguish the $88 million outstanding on the Two-Month Bridge Loan in June 2007.

Approximate future maturities of long-term debt in the year indicated are as follows at December 31, 2007:

Debt Maturities (millions)	
2010	$ 800
2011	250
2012	630
Thereafter	1,258
	2,938
Unamortized discount	(8)
Long-term debt	$2,930

11. Risk Management and Derivative Activities, Credit Risk and Financial Instruments

The impact of our derivative activity on our results of operations and financial position is summarized below:

	For the Years Ended December 31, 2007	2006 (millions)	2005
Commodity derivative instruments:			
Gains reclassified into earnings	$ 1	$ 4	$—
Commodity derivative activity:			
Unrealized (losses) gains from derivative activity	$(102)	$ 6	$ (6)
Realized gains (losses) from derivative activity	$ 59	$ 71	$ (9)
Interest rate derivative instruments:			
Losses reclassified into earnings	$ (1)	$ (1)	$ (1)

	December 31, 2007	2006 (millions)
Commodity derivative instruments:		
Net deferred (losses) gains in AOCI	$ (1)	$ 3
Interest rate derivative instruments:		
Net deferred losses in AOCI	$ (10)	$ (7)
Interest rate fair value hedges:		
Unrealized gains	$ 8	$ 4

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For the years ended December 31, 2007 and 2006, no derivative gains or losses were reclassified from AOCI to current period earnings as a result of the discontinuance of cash flow hedges related to certain forecasted transactions that are not probable of occurring.

Commodity Price Risk—Our principal operations of gathering, processing, compression, transportation and storage of natural gas, and the accompanying operations of fractionation, transportation, gathering, treating, processing, storage and trading and marketing of NGLs create commodity price risk exposure due to market fluctuations in commodity prices, primarily with respect to the prices of NGLs, natural gas and crude oil. As an owner and operator of natural gas processing and other midstream assets, we have an inherent exposure to market variables and commodity price risk. The amount and type of price risk is dependent on the underlying natural gas contracts entered into to purchase and process raw natural gas. Risk is also dependent on the types and mechanisms for sales of natural gas and NGLs, and related products produced, processed, transported or stored.

Energy Trading (Market) Risk—Certain of our subsidiaries are engaged in the business of trading energy related products and services, including managing purchase and sales portfolios, storage contracts and facilities, and transportation commitments for products. These energy trading operations are exposed to market variables and commodity price risk with respect to these products and services, and we may enter into physical contracts and financial instruments with the objective of realizing a positive margin from the purchase and sale of commodity-based instruments.

Interest Rate Risk—We enter into debt arrangements that have either fixed or floating rates, therefore we are exposed to market risks related to changes in interest rates. We periodically use interest rate swaps to hedge interest rate risk associated with our debt. Our primary goals include (1) maintaining an appropriate ratio of fixed-rate debt to floating-rate debt; (2) reducing volatility of earnings resulting from interest rate fluctuations; and (3) locking in attractive interest rates based on historical rates.

Credit Risk—Our principal customers range from large, natural gas marketing services to industrial end-users for our natural gas products and services, as well as large multi-national petrochemical and refining companies, to small regional propane distributors for our NGL products and services. Substantially all of our natural gas and NGL sales are made at market-based prices. Approximately 40% of our NGL production is committed to ConocoPhillips and CP Chem under an existing 15-year contract, which expires in 2015. This concentration of credit risk may affect our overall credit risk, in that these customers may be similarly affected by changes in economic, regulatory or other factors. Where exposed to credit risk, we analyze the counterparties' financial condition prior to entering into an agreement, establish credit limits and monitor the appropriateness of these limits on an ongoing basis. We may use master collateral agreements to mitigate credit exposure. Collateral agreements provide for a counterparty to post cash or letters of credit for exposure in excess of the established threshold. The threshold amount represents an open credit limit, determined in accordance with our credit policy. The collateral agreements also provide that the inability to post collateral is sufficient cause to terminate a contract and liquidate all positions. In addition, our standard gas and NGL sales contracts contain adequate assurance provisions, which allow us to suspend deliveries and cancel agreements, or continue deliveries to the buyer after the buyer provides security for payment in a satisfactory form.

As of December 31, 2007, we held deposits, of $57 million included in other current liabilities, and letters of credit, of $97 million, from counterparties to secure their future performance of financial or physical contracts. We had deposits with counterparties of $45 million, included in other current assets, of such collateral to secure our obligations to provide future services or to perform under financial contracts. Collateral amounts held or posted may be fixed or may vary, depending on the value of the underlying contracts, and could cover normal purchases and sales, trading and hedging contracts. In many cases, we and our counterparties publicly disclose credit ratings, which may impact the amounts of collateral requirements.

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Physical forward contracts and financial derivatives are generally cash settled at the expiration of the contract term. These transactions are generally subject to specific credit provisions within the contracts that would allow the seller, at its discretion, to suspend deliveries, cancel agreements or continue deliveries to the buyer after the buyer provides security for payment satisfactory to the seller.

Commodity Derivative Activity—Our operations of gathering, processing, and transporting natural gas, and the related operations of transporting and marketing of NGL create commodity price risk due to market fluctuations in commodity prices, primarily with respect to the prices of NGL, natural gas and crude oil.

We manage our commodity derivative activities in accordance with our risk management policy, which limits exposure to market risk and requires regular reporting to management of potential financial exposure.

Commodity Cash Flow Protection Activities—DCP Partners uses NGL, natural gas and crude oil swaps to mitigate the risk of market fluctuations in the price of NGL, natural gas and condensate. Prior to July 1, 2007, the effective portion of the change in fair value of a derivative designated as a cash flow hedge was accumulated in AOCI. During the period in which the hedged transaction impacted earnings, amounts in AOCI associated with the hedged transaction were reclassified to the consolidated statements of operations and comprehensive income in the same accounts as the item being hedged.

Effective July 1, 2007, we elected to discontinue using the hedge method of accounting for our commodity cash flow hedges. Therefore, we are using the mark-to-market method of accounting for all commodity derivative instruments. As a result, the remaining net loss deferred in AOCI will be reclassified to sales of natural gas and petroleum products through December 2011, as the hedged transactions impact earnings. Deferred net losses of less than $1 million are expected to be reclassified into earnings during the next 12 months. Subsequent to July 1, 2007, the changes in fair value of these financial derivatives are included in trading and marketing gains and losses in the consolidated statements of operations and comprehensive income.

As of December 31, 2007, DCP Partners has mitigated a portion of our expected natural gas, NGL and condensate commodity price risk associated with the equity volumes from their gathering and processing operations through 2013 with natural gas, NGL and crude oil derivatives.

Commodity Fair Value Hedges—Historically, we used fair value hedges to mitigate risk to changes in the fair value of an asset or a liability (or an identified portion thereof) that is attributable to fixed price risk. We may hedge producer price locks (fixed price gas purchases) and market locks (fixed price gas sales) to reduce our cash flow exposure to fixed price risk via swapping the fixed price risk for a floating price position (New York Mercantile Exchange or index based).

Normal Purchases and Normal Sales—If a contract qualifies and is designated as a normal purchase or normal sale, no recognition of the contract's fair value in the consolidated financial statements is required until the associated delivery period impacts earnings. We have applied this accounting election for contracts involving the purchase or sale of physical natural gas, propane or NGLs in future periods.

Commodity Derivatives—Trading and Marketing—Our trading and marketing program is designed to realize margins related to fluctuations in commodity prices and basis differentials, and to maximize the value of certain storage and transportation assets. Certain of our subsidiaries are engaged in the business of trading energy related products and services including managing purchase and sales portfolios, storage contracts and facilities, and transportation commitments for products. These energy trading operations are exposed to market variables

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and commodity price risk with respect to these products and services, and may enter into physical contracts and financial instruments with the objective of realizing a positive margin from the purchase and sale of commodity-based instruments. We manage our trading and marketing portfolio with strict policies, which limit exposure to market risk, and require daily reporting to management of potential financial exposure. These policies include statistical risk tolerance limits using historical price movements to calculate daily value at risk.

Interest Rate Cash Flow Hedges—DCP Partners mitigates a portion of their interest rate risk with interest rate swaps, which reduce the exposure to market rate fluctuations by converting variable interest rates to fixed interest rates. These interest rate swaps convert the interest rate associated with an aggregate of $425 million of the variable rate exposure to a fixed rate obligation, thereby reducing the exposure to market rate fluctuations. All interest rate swap agreements have been designated as cash flow hedges, and effectiveness is determined by matching the principal balance and terms with that of the specified obligation. The effective portions of changes in fair value are recognized in AOCI in the consolidated balance sheets. As of December 31, 2007, $2 million of deferred net losses on derivative instruments in AOCI are expected to be reclassified into earnings during the next 12 months as the hedged transactions impact earnings however, due to the volatility of the interest rate markets, the corresponding value in AOCI is subject to change prior to its reclassification into earnings. Ineffective portions of changes in fair value are recognized in earnings. The agreements reprice prospectively approximately every 90 days. Under the terms of the interest rate swap agreements, we pay fixed rates ranging from 3.97% to 5.19%, and receive interest payments based on the three-month LIBOR. The differences to be paid or received under the interest rate swap agreements are recognized as an adjustment to interest expense. The agreements are with major financial institutions, which are expected to fully perform under the terms of the agreements.

Interest Rate Fair Value Hedges—In August 2003, we entered into two interest rate swaps to convert $100 million of fixed-rate debt securities issued in August 2000 to floating rate debt. These interest rate fair value hedges are at a floating rate based on six-month LIBOR, which is re-priced semiannually through 2030. The swaps meet conditions that permit the assumption of no ineffectiveness. As such, for the life of the swaps no ineffectiveness will be recognized.

12. Non-Controlling Interest

Non-controlling interest represents the ownership interests of third-party entities in net assets of various equity method investments in consolidated affiliates, including ownership interest of DCP Partners' public unitholders in net assets of DCP Partners through DCP Partners' publicly traded common units, and in net assets of DCP East Texas Holdings, LLC, of which DCP Partners acquired a 25% equity interest in July 2007 as well as Collbran Valley Gas Gathering, which was acquired in conjunction with the MEG acquisition in August 2007. For financial reporting purposes, the assets and liabilities of these entities are consolidated with those of our own, with any third party and affiliate investors' interest in our consolidated balance sheet amounts shown as non-controlling interest. Distributions to and contributions from non-controlling interests represent cash payments and cash contributions, respectively, from such third-party and affiliate investors.

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13. Stock-Based Compensation

We recorded stock-based compensation expense as follows, the components of which are further described below:

	For the Years Ended December 31, 2007	2006 (millions)	2005
DCP Midstream, LLC Long-Term Incentive Plan (2006 Plan)	$ 4	$ 1	$ —
DCP Partners' Long-Term Incentive Plan (DCP Partners' Plan)	2	1	—
Duke Energy 1998 Plan and Spectra Energy Long-Term Incentive Plan	1	6	5
Total	$ 7	$ 8	$ 5

	Vesting Period (years)	Unrecognized Compensation Expense at December 31, 2007 (millions)	Estimated Forfeiture Rate	Weighted-Average Remaining Vesting (years)
DCP Midstream's 2006 Plan:				
Relative Performance Units (RPUs)	8	$ 1	64%	6
Strategic Performance Units (SPUs)	3	$ 4	12%/32%	2
Phantom Units	5	$ 1	19%	4
DCP Partners' Phantom Units	3	$ 1	12%/32%	1
DCP Partners' Plan:				
Performance Units	3	$ 1	0%	2
Phantom Units	3	$ —	0%	1
Duke Energy's 1998 Plan and Spectra Energy's 2007 LTIP Plan:				
Stock Options (no activity in 2006 or 2007)	0-10	$ —	NA	—
Stock Based Performance Awards	3	$ —	0-8%	1
Phantom Awards	1-5	$ —	4-5%	2
Other Stock Awards	1-5	$ —	NA	—

DCP Midstream, LLC Long-Term Incentive Plan, or 2006 Plan—Under our 2006 Long Term Incentive Plan, or 2006 Plan, equity instruments may be granted to our key employees. The 2006 Plan provides for the grant of Relative Performance Units, or RPUs, Strategic Performance Units, or SPUs, and Phantom Units. The RPUs, SPUs and Phantom Units consist of a notional unit based on the value of common shares or units of ConocoPhillips, Duke Energy, Spectra Energy and DCP Partners. The weighting varies depending on when the units were granted. The DCP Partners' Phantom Units constitute a notional unit equal to the fair value of DCP Partners' common units. Each award provides for the grant of dividend or distribution equivalent rights. The 2006 Plan is administered by the compensation committee of our board of directors. We first granted awards under the 2006 Plan during the second quarter of 2006. All awards are subject to cliff vesting.

Relative Performance Units—The number of RPUs that will ultimately vest range from 0% to 200% of the outstanding RPUs, depending on the achievement of specified performance targets over a three year period ending in January 2009 and 2010, respectively, for units granted in 2006 and 2007. The final performance payout is determined by the compensation committee of our board of directors. After the performance period, vesting

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occurs over five years, at the end of which the value is based on the participant's investment elections during the deferral period. Dividend or distribution equivalent rights will be paid in cash at the end of the performance period. The following tables presents information related to RPUs:

	Units	Grant Date Weighted-Average Price Per Unit	Measurement Date Weighted-Average Price Per Unit
Outstanding at December 31, 2005	—	$ —	
Granted	44,080	$ 42.89	
Outstanding at December 31, 2006	44,080	$ 42.89	
Granted	42,340	$ 43.98	
Forfeited	(21,237)	$ 43.55	
Vested or paid in cash	(3,016)	$ 42.86	
Outstanding at December 31, 2007	62,167	$ 43.41	$ 54.84
Expected to vest	33,041	$ 43.41	$ 54.84

Strategic Performance Units—The number of SPUs that will ultimately vest range from 0% to 150% of the outstanding SPUs, depending on the achievement of specified performance targets over a three year period ending on December 31, 2008 and 2009, respectively, for units granted in 2006 and 2007. The final performance payout is determined by the compensation committee of our board of directors. Dividend or distribution equivalent rights will be paid in cash at the end of the performance period. The following tables presents information related to SPUs:

	Units	Grant Date Weighted-Average Price Per Unit	Measurement Date Weighted-Average Price Per Unit
Outstanding at December 31, 2005	—	$ —	
Granted	84,960	$ 42.92	
Outstanding at December 31, 2006	84,960	$ 42.92	
Granted	86,380	$ 44.04	
Forfeited	(28,305)	$ 43.51	
Vested or paid in cash	(3,016)	$ 42.86	
Outstanding at December 31, 2007	140,019	$ 43.49	$ 54.84
Expected to vest	127,432	$ 43.49	$ 54.84

The estimate of RPUs and SPUs that are expected to vest is based on highly subjective assumptions that could potentially change over time, including the expected forfeiture rate and achievement of performance targets. Therefore the amounts of unrecognized compensation expense noted above does not necessarily represent the value that will ultimately be realized in our consolidated statements of operations and comprehensive income.

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Phantom Units—Dividend or distribution equivalent rights are paid quarterly in arrears. The following table presents information related to Phantom Units:

	Units	Grant Date Weighted-Average Price Per Unit	Measurement Date Weighted-Average Price Per Unit
Outstanding at December 31, 2005	—	$ —	
Granted	17,460	$ 42.95	
Outstanding at December 31, 2006	17,460	$ 42.95	
Granted	19,450	$ 44.10	
Forfeited	(2,930)	$ 43.42	
Vested or paid in cash	(180)	$ 42.86	
Outstanding at December 31, 2007	33,800	$ 43.57	$ 54.84
Expected to vest	29,931	$ 43.57	$ 54.84

DCP Partners' Phantom Units—The distribution equivalent rights are paid quarterly in arrears. The following table presents information related to the DCP Partners' Phantom Units:

	Units	Grant Date Weighted-Average Price Per Unit	Measurement Date Weighted-Average Price Per Unit
Outstanding at December 31, 2005	—	$ —	
Granted	47,750	$ 28.60	
Outstanding at December 31, 2006	47,750	$ 28.60	
Granted	13,500	$ 50.57	
Forfeited	(2,000)	$ 28.60	
Vested or paid in cash	(7,500)	$ 28.60	
Outstanding at December 31, 2007	51,750	$ 34.33	$ 45.95
Expected to vest	46,080	$ 34.33	$ 45.95

DCP Partners' Long-Term Incentive Plan, or DCP Partners' Plan—Under DCP Partners' Long Term Incentive Plan, or DCP Partners' Plan, which was adopted by DCP Midstream GP, LLC, equity instruments may be granted to key employees, consultants and directors of DCP Midstream GP, LLC and its affiliates who perform services for DCP Partners. The DCP Partners' Plan provides for the grant of limited partner units, or LPUs, phantom units, unit options and substitute awards, and, with respect to unit options and phantom units, the grant of dividend equivalent rights, or DERs. Subject to adjustment for certain events, an aggregate of 850,000 common units may be delivered pursuant to awards under the DCP Partners' Plan. Awards that are canceled, forfeited or withheld to satisfy DCP Midstream GP, LLC's tax withholding obligations are available for delivery pursuant to other awards. The DCP Partners' Plan is administered by the compensation committee of DCP Midstream GP, LLC's board of directors. All awards are subject to cliff vesting, with the exception of the Phantom Units issued to the directors in conjunction with the initial public offering, which are subject to graded vesting provisions.

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Awards granted to directors are accounted for as equity-based awards and all other awards are accounted for as liability awards.

Performance Units—The number of Performance Units that will ultimately vest range from 0% to 150% of the outstanding Performance Units, depending on the achievement of specified performance targets over three year performance periods. The final performance percentage payout is determined by the compensation committee of DCP Partners' board of directors. The DERs will be paid in cash at the end of the performance period. Of the remaining Performance Units outstanding at December 31, 2007, 28,350 units are expected to vest on December 31, 2008 and 27,150 units are expected to vest on December 31, 2009. The following tables presents information related to the Performance Units:

	Units	Grant Date Weighted-Average Price Per Unit	Measurement Date Weighted-Average Price Per Unit
Outstanding at December 31, 2005	—	$ —	
Granted	40,560	$ 26.96	
Forfeited	(17,470)	$ 26.96	
Outstanding at December 31, 2006	23,090	$ 26.96	
Granted	29,610	$ 37.29	
Forfeited	(5,740)	$ 31.39	
Outstanding at December 31, 2007	46,960	$ 32.93	$ 45.95
Expected to vest(a)	55,500	$ 32.93	$ 45.95

(a) Based on our December 31, 2007 estimated achievement of specified performance targets, the number of performance units granted in 2006 that will ultimately vest is estimated at 143% of the targeted units granted.

The estimate of Performance Units that are expected to vest is based on highly subjective assumptions that could potentially change over time, including the expected forfeiture rate and achievement of performance targets. Therefore the amount of unrecognized compensation expense noted above does not necessarily represent the value that will ultimately be realized in our consolidated statements of operations and comprehensive income.

Phantom Units—In conjunction with their initial public offering, in January 2006 DCP Partners awarded Phantom Units to key employees, and to directors who are not officers or employees of DCP Midstream GP, LLC, or its affiliates who perform services for DCP Partners. Of the remaining Phantom Units outstanding at December 31, 2007, 2,001 units are expected to vest on January 3, 2008 and 17,698 units are expected to vest on January 3, 2009.

In 2007, DCP Partners granted 4,500 Phantom Units pursuant to the DCP Partners' Plan, to directors who are not officers or employees of affiliates of DCP Midstream as part of their annual director fees for 2007. Of these Phantom Units, 4,000 units vested during 2007 and 500 units are expected to vest on February 7, 2008.

The DERs are paid quarterly in arrears.

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The following table presents information related to the Phantom Units:

	Units	Grant Date Weighted-Average Price Per Unit	Measurement Date Weighted-Average Price Per Unit
Outstanding at December 31, 2005	—	$ —	
Granted	35,900	$ 24.05	
Forfeited	(11,200)	$ 24.05	
Outstanding at December 31, 2006	24,700	$ 24.05	
Granted	4,500	$ 42.90	
Forfeited	(2,333)	$ 24.05	
Vested	(6,668)	$ 35.23	
Outstanding at December 31, 2007	20,199	$ 24.56	$ 45.95
Expected to vest	20,199	$ 24.56	$ 45.95

The estimate of Phantom Units that are expected to vest is based on highly subjective assumptions that could potentially change over time, including the expected forfeiture rate. Therefore the amount of unrecognized compensation expense noted above does not necessarily represent the value that will ultimately be realized in our consolidated statements of operations and comprehensive income.

During the year ended December 31, 2007, 2,668 units vested and were settled in cash for less than $1 million, and 4,000 units were settled with the issuance of limited partner units.

All awards issued under the 2006 Plan and the DCP Partners' Plan are intended to be settled in cash or stock upon vesting. Compensation expense is recognized ratably over each vesting period, and will be remeasured quarterly for all awards outstanding until the units are vested. The fair value of all awards is determined based on the closing price of the relevant underlying securities at each measurement date.

Duke Energy 1998 Plan and Spectra Energy 2007 Long-Term Incentive Plan—Under the Duke Energy 1998 Plan, or the 1998 Plan, Duke Energy granted certain of our key employees stock options, stock-based performance awards, phantom stock awards and other stock awards to be settled in shares of Duke Energy's common stock, or the Stock-Based Awards. Upon execution of the 50-50 Transaction in July 2005, our employees incurred a change in status from Duke Energy employees to non-employees. As a result, we began accounting for these awards using the fair value method. No awards have been and we do not expect to settle any awards granted under the 1998 Plan with cash.

In connection with the Spectra spin, one replacement Duke Energy Stock-Based Award and one-half Spectra Energy Stock-Based Award were distributed to each holder of Duke Energy Stock-Based Awards for each award held at the time of the Spectra spin. Substantially all converted Stock-Based Awards are subject to the terms and conditions applicable to the original Duke Energy Stock-Based Awards. The Spectra Energy Stock-Based Awards resulting from the conversion are considered to have been issued under the Spectra Energy 2007 Long-Term Incentive Plan, or the Spectra Energy 2007 LTIP.

The Spectra Energy 2007 LTIP provides for the granting of stock options, restricted stock awards and units, unrestricted stock awards and units, and other equity-based awards, to employees and other key individuals who

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perform services for Spectra Energy. A maximum of 30 million shares of common stock may be awarded under the Spectra Energy 2007 LTIP. Options granted under the Spectra Energy 2007 LTIP are issued with exercise prices equal to the fair market value of Spectra Energy common stock on the grant date, have ten year terms, and vest immediately or over terms not to exceed five years. Compensation expense related to stock options is recognized over the requisite service period. The requisite service period for stock options is the same as the vesting period, with the exception of retirement eligible employees, who have shorter requisite service periods ending when the employees become retirement eligible. Restricted, performance and phantom stock awards granted under the Spectra Energy 2007 LTIP typically become 100% vested on the three-year anniversary of the grant date. The fair value of the awards granted is measured based on the fair market value of the shares on the date of grant, and the related compensation expense is recognized over the requisite service period which is the same as the vesting period.

Stock Options—Under the 1998 Plan, the exercise price of each option granted could not be less than the market price of Duke Energy's common stock on the date of grant. Effective July 1, 2005, these options were accounted using the fair value method. As a result, compensation expense subsequent to July 1, 2005, is recognized based on the change in the fair value of the stock options at each reporting date until vesting.

The following table shows information regarding options to purchase Duke Energy's common stock granted to our employees, reflecting shares outstanding as impacted by the conversion.

	Shares	Weighted-Average Exercise Price	Weighted-Average Remaining Life (years)	Aggregate Intrinsic Value (millions)
Outstanding at December 31, 2005	2,592,567	$ 29.46	5.2	
Exercised	(367,088)	$ 21.15		
Forfeited	(124,417)	$ 29.96		
Effect of conversion	(258,058)			
Outstanding at December 31, 2006	1,843,004	$ 17.85	4.1	
Exercised	(21,960)	$ 13.89		
Forfeited	(5,088)	$ 22.90		
Outstanding at December 31, 2007	1,815,956	$ 17.89	3.2	$ 7
Exercisable at December 31, 2007	1,815,956	$ 17.89	3.2	$ 7

The total intrinsic value of options exercised during the years ended December 31, 2007 and 2006, was less than $1 million and approximately $3 million, respectively.

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The following table shows information regarding options to purchase Spectra Energy's common stock granted to our employees, reflecting shares outstanding as impacted by the conversion.

	Shares	Weighted-Average Exercise Price	Weighted-Average Remaining Life (years)	Aggregate Intrinsic Value (millions)
Outstanding at December 31, 2005	—	$ —		
Effect of conversion	1,066,595			
Outstanding at December 31, 2006	1,066,595	$ 26.43	4.1	
Exercised	(73,920)	$ 17.84		
Forfeited	(55,427)	$ 31.78		
Outstanding at December 31, 2007	937,248	$ 26.80	3.2	$ 3
Exercisable at December 31, 2007	937,248	$ 26.80	3.2	$ 3

The total intrinsic value of options exercised during the years ended December 31, 2007 was approximately $1 million.

Stock-Based Performance Awards—There were no stock-based performance awards granted during the years ended December 31, 2007 and 2006.

The following tables summarize information about stock-based performance awards activity, reflecting shares outstanding as impacted by the conversion:

Duke Energy 1998 Plan	Shares	Grant Date Weighted-Average Price Per Unit	Measurement Date Weighted-Average Price Per Unit
Outstanding at December 31, 2005	342,453	$ 23.88	
Forfeited	(40,835)	$ 23.85	
Effect of conversion	(128,213)		
Outstanding at December 31, 2006	173,405	$ 15.58	
Forfeited	(40)	$ 15.38	
Outstanding at December 31, 2007	173,365	$ 15.58	$ 20.17
Expected to vest	173,325	$ 15.58	$ 20.17

Spectra Energy 2007 LTIP	Shares	Grant Date Weighted-Average Price Per Unit	Measurement Date Weighted-Average Price Per Unit
Outstanding at December 31, 2005	—	$ —	
Effect of conversion	184,083		
Outstanding at December 31, 2006	184,083	$ 20.93	
Vested	(83,309)	$ 18.30	
Forfeited	(14,091)	$ 20.42	
Outstanding at December 31, 2007	86,683	$ 23.54	$ 25.82
Expected to vest	80,048	$ 23.54	$ 25.82

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The total fair value of the performance stock awards that vested during the year ended December 31, 2007 was approximately $2 million. No awards were granted, vested or canceled during the years ended December 31, 2007 and 2006.

Phantom Stock Awards—There were no phantom stock awards granted during the years ended December 31, 2007 and 2006.

The following tables summarize information about phantom stock awards activity, reflecting shares outstanding as impacted by the conversion:

Duke Energy 1998 Plan	Shares	Grant Date Weighted-Average Price Per Unit	Measurement Date Weighted-Average Price Per Unit
Outstanding at December 31, 2005	241,216	$ 24.22	
Vested	(54,150)	$ 23.90	
Forfeited	(22,378)	$ 24.29	
Effect of conversion	(52,664)		
Outstanding at December 31, 2006	112,024	$ 15.59	
Vested	(29,190)	$ 15.54	
Forfeited	(5,624)	$ 15.38	
Outstanding at December 31, 2007	77,210	$ 15.62	$ 20.17
Expected to vest	73,960	$ 15.62	$ 20.17

Spectra Energy 2007 LTIP	Shares	Grant Date Weighted-Average Price Per Unit	Measurement Date Weighted-Average Price Per Unit
Outstanding at December 31, 2005	—	$ —	
Effect of conversion	104,171		
Outstanding at December 31, 2006	104,171	$ 21.31	
Vested	(59,258)	$ 19.66	
Forfeited	(6,308)	$ 22.81	
Outstanding at December 31, 2007	38,605	$ 23.60	$ 25.82
Expected to vest	36,487	$ 23.60	$ 25.82

The total fair value of the phantom stock awards that vested during the years ended December 31, 2007 and 2006 was approximately $2 million for both periods. No awards were granted or canceled during the years ended December 31, 2007 and 2006.

Other Stock Awards—There were no other stock awards granted during the years ended December 31, 2007 and 2006.

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The following tables summarize information about other stock awards activity, reflecting shares outstanding as impacted by the conversion:

Duke Energy 1998 Plan	Shares	Grant Date Weighted-Average Price Per Unit	Measurement Date Weighted-Average Price Per Unit
Outstanding at December 31, 2005	45,400	$ 21.73	
Vested	(10,600)	$ 21.73	
Forfeited	(13,200)	$ 21.73	
Outstanding at December 31, 2006	21,600	$ 12.38	
Vested	(21,600)	$ 12.38	
Forfeited	—	$ —	
Outstanding at December 31, 2007	—	$ —	$ —
Expected to vest	—	$ —	$ —

Spectra Energy 2007 LTIP	Shares	Grant Date Weighted-Average Price Per Unit	Measurement Date Weighted-Average Price Per Unit
Outstanding at December 31, 2005	—	$ —	
Effect of conversion	10,800		
Outstanding at December 31, 2006	10,800	$ 18.71	
Vested	(10,800)	$ 18.71	
Forfeited	—	$ —	
Outstanding at December 31, 2007	—	$ —	$ —
Expected to vest	—	$ —	$ —

The total fair value of the other stock awards that vested during the years ended December 31, 2007 and 2006 was not significant. No awards were granted or canceled during the years ended December 31, 2007 and 2006.

14. Benefits

All Company employees who are 18 years old and work at least 20 hours per week are eligible for participation in our 401(k) and retirement plan, to which we contributed 4% of each eligible employee’s qualified earnings through December 31, 2006. Effective January 1, 2007, we began contributing a range of 4% to 7% of each eligible employee’s qualified earnings to the retirement plan, based on years of service. Additionally, we match employees’ contributions in the 401(k) plan up to 6% of qualified earnings. During 2007 we expensed plan contributions of $17 million and during 2006 and 2005 we expensed plan contributions of $15 million in both periods.

We offer certain eligible executives the opportunity to participate in DCP Midstream LP’s Non-Qualified Executive Deferred Compensation Plan. This plan allows participants to defer current compensation on a pre-tax basis and to receive tax deferred earnings on such contributions. The plan also has make-whole provisions for plan participants who may otherwise be limited in the amount that we can contribute to the 401(k) plan on the

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participant's behalf. All amounts contributed to or earned by the plan's investments are held in a trust account for the benefit of the participants. The trust and the liability to the participants are part of our general assets and liabilities, respectively.

15. Income Taxes

We are structured as a limited liability company, which is a pass-through entity for United States income tax purposes. We own a corporation that files its own federal, foreign and state corporate income tax returns. The income tax expense related to this corporation is included in our income tax expense, along with state and local taxes of the limited liability company and other subsidiaries. In addition, until July 1, 2005, we had Canadian subsidiaries that were subject to Canadian income taxes. Taxes associated with these subsidiaries have been reclassified to discontinued operations for year ended December 31, 2005.

In May 2006, the State of Texas enacted a margin-based franchise tax law that replaced the existing franchise tax, commonly referred to as the Texas margin tax. The Texas margin tax is assessed at 1% of taxable margin apportioned to Texas. As a result of the change in Texas franchise law, our status in the state of Texas changed from non-taxable to taxable. Since the Texas margin tax is considered an income tax, in the second quarter of 2006 we recorded a non-current deferred tax liability of $18 million. The Texas margin tax becomes effective for franchise tax reports due on or after January 1, 2008. The 2008 tax will be based on revenues earned during the 2007 fiscal year. Accordingly, we recorded current tax expense for the Texas margin tax, beginning in 2007.

Income tax expense consists of the following:

	For the Years Ended December 31,		
	2007	2006 (millions)	2005
Current:			
Federal	$ 5	$ 5	$ 9
State	11	1	2
Deferred:			
Federal	(4)	—	—
State	(1)	17	(2)
Total income tax expense	$ 11	$ 23	$ 9

Temporary differences for our federal deferred tax assets of $7 million primarily relate to basis differences between property, plant and equipment, and investments in consolidated affiliates. Temporary differences for our state deferred tax liabilities of $16 million primarily relate to basis differences between property, plant and equipment.

Our effective tax rate differs from statutory rates, primarily due to our being structured as a limited liability company, which is a pass-through entity for United States income tax purposes, while being treated as a taxable entity in certain states.

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16. Commitments and Contingent Liabilities

Litigation—The midstream industry has seen a number of class action lawsuits involving royalty disputes, mismeasurement and mispayment allegations. Although the industry has seen these types of cases before, they were typically brought by a single plaintiff or small group of plaintiffs. A number of these cases are now being brought as class actions. We are currently named as defendants in some of these cases. Management believes we have meritorious defenses to these cases and, therefore, will continue to defend them vigorously. These class actions, however, can be costly and time consuming to defend. We are also a party to various legal, administrative and regulatory proceedings that have arisen in the ordinary course of our business.

In December 2006, El Paso E&P Company, L.P., or El Paso, filed a lawsuit against one of our subsidiaries, DCP Assets Holding, LP and an affiliate of DCP Midstream GP, LP, in District Court, Harris County, Texas. The litigation stems from an ongoing commercial dispute involving DCP Partners' Minden processing plant that dates back to August 2000. El Paso claims damages, including interest, in the amount of $6 million in the litigation, the bulk of which stems from audit claims under our commercial contract. It is not possible to predict whether we will incur any liability or to estimate the damages, if any, we might incur in connection with this matter.

Management currently believes that these matters, taken as a whole, and after consideration of amounts accrued, insurance coverage and other indemnification arrangements, will not have a material adverse effect upon our consolidated results of operations, financial position or cash flows.

In October 2007, we settled a lawsuit alleging migration of acid gas from a storage formation into a third party producing formation. Pending regulatory approval, we will obtain the rights to the producing formation. This matter did not have a material adverse effect upon our consolidated results of operations, financial position or cash flows.

General Insurance—Effective August 2006, Midstream's insurance coverage is carried with an affiliate of ConocoPhillips and third party insurers. Prior to August 2006, Midstream carried a portion of their insurance coverage with an affiliate of Duke Energy Corporation. Midstream's insurance coverage includes: (1) general liability insurance covering third party exposures; (2) statutory workers' compensation insurance; (3) automobile liability insurance for all owned, non-owned and hired; (4) excess liability insurance above the established primary limits for general liability and automobile liability insurance; (5) property insurance, which covers the replacement value of all real and personal property and includes business interruption/extra expense; and (6) directors and officers insurance covering our directors and officers for acts related to our business activities. All coverage is subject to certain limits and deductibles, the terms and conditions of which are common for companies with similar types of operations.

During the third quarter of 2004, certain assets, located in the Gulf Coast, were damaged as a result of hurricane Ivan. Also, during the third quarter of 2005, hurricanes Katrina and Rita forced us to temporarily shut down our operations at certain assets located in Alabama, Louisiana, Texas and New Mexico. Several of our assets sustained property damage, including some of our operating equipment on a platform in the Gulf of Mexico. A portion of the resulting lost revenues and property damages were covered by our insurance, subject to applicable deductibles. The financial impact of hurricanes has increased market rates for insurance coverage; however, these increases did not have a material adverse effect on our consolidated results of operations, financial position or cash flows. Insurance recovery receivables and business interruption recoveries related to these hurricanes are detailed in Note 3.

Environmental—The operation of pipelines, plants and other facilities for gathering, transporting, processing, treating, or storing natural gas, NGLs and other products is subject to stringent and complex laws and regulations pertaining to health, safety and the environment. As an owner or operator of these facilities, we must

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DCP MIDSTREAM, LLC

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — Continued
YEARS ENDED DECEMBER 31, 2007, 2006 AND 2005

comply with United States laws and regulations at the federal, state and local levels that relate to air and water quality, hazardous and solid waste management and disposal, and other environmental matters. The cost of planning, designing, constructing and operating pipelines, plants, and other facilities must incorporate compliance with environmental laws and regulations and safety standards. Failure to comply with these laws and regulations may trigger a variety of administrative, civil and potentially criminal enforcement measures, including citizen suits, which can include the assessment of monetary penalties, the imposition of remedial requirements, the issuance of injunctions or restrictions on operation. Management believes that, based on currently known information, compliance with these laws and regulations will not have a material adverse effect on our consolidated results of operations, financial position or cash flows.

On July 20, 2006, the State of New Mexico Environment Department issued Compliance Orders to us that list air quality violations during the past five years at six of our owned or operated facilities in New Mexico. The orders allege a number of violations related to excess emissions beginning January 2001, and further require us to install flares for smokeless operations and to use the flares only for emergency purposes. Management does not believe the ultimate resolution of this issue will have a material adverse effect on our consolidated results of operations, financial position or cash flows.

Other Commitments and Contingencies—In June 2007, DCP Partners entered into a private placement agreement with a group of institutional investors for $130 million, representing 3,005,780 common limited partner units at a price of $43.25 per unit, and received proceeds of $129 million, net of offering costs. In August 2007, DCP Partners issued 2,380,952 common limited partner units in a private placement, pursuant to a common unit purchase agreement with private owners of MEG or affiliates of such owners, at $42.00 per unit, or approximately $100 million in the aggregate. In January 2008, DCP Partners' registration statement on Form S-3 to register the common limited partner units represented in the private placement agreements was declared effective by the Securities and Exchange Commission.

We utilize assets under operating leases in several areas of operations. Consolidated rental expense, including leases with no continuing commitment, amounted to $41 million, $37 million and $36 million in 2007, 2006 and 2005, respectively. Rental expense for leases with escalation clauses is recognized on a straight line basis over the initial lease term.

Minimum rental payments under our various operating leases in the year indicated are as follows:

	Minimum Rental Payments (millions)
2008	$ 24
2009	19
2010	18
2011	17
2012	15
Thereafter	31
Total gross payments	124
Sublease receipts	(1)
Total net payments	$123

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DCP MIDSTREAM, LLC

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — Continued
YEARS ENDED DECEMBER 31, 2007, 2006 AND 2005

17. Guarantees and Indemnifications

We have signed a corporate guaranty, pursuant to which we are the guarantor of a maximum of approximately $1 million and $10 million of construction obligations as of December 31, 2007 and 2006, respectively. The guaranty will expire upon completion and payment for construction of a pipeline expected to be completed during 2008. The fair value of this guarantee is not significant to our consolidated results of operations, financial position or cash flows.

We periodically enter into agreements for the acquisition or divestiture of assets. These agreements contain indemnification provisions that may provide indemnity for environmental, tax, employment, outstanding litigation, breaches of representations, warranties and covenants, or other liabilities related to the assets being acquired or divested. Claims may be made by third parties under these indemnification agreements for various periods of time depending on the nature of the claim. The effective periods on these indemnification provisions generally have terms of one to five years, although some are longer. Our maximum potential exposure under these indemnification agreements can vary depending on the nature of the claim and the particular transaction. We are unable to estimate the total maximum potential amount of future payments under indemnification agreements due to several factors, including uncertainty as to whether claims will be made under these indemnities.

18. Supplementary Cash Flow Information

	December 31,		
	2007	2006	2005
		(millions)	
Cash paid for interest:			
Cash paid for interest expense, net of capitalized interest	$159	$141	$163
Cash paid for income taxes	$ 11	$ 10	$ 13
Non-cash investing and financing activities:			
Non-cash additions of property, plant and equipment	$ 8	$ 10	$ 13
Distributions payable to members	$123	$127	$185

19. Subsequent Events

On January 24, 2008, DCP Partners announced the declaration of a cash distribution of $0.57 per unit that was paid on February 14, 2008 to unitholders of record on February 7, 2008.

In January 2008, we received a distribution from Discovery of $11 million.

In February 2008, 50% of our subordinated units in DCP Partners, or 3,571,428 subordinated units, were converted to common units in accordance with the early termination provision in DCP Partners' partnership agreement.

Subsequent to December 31, 2007, DCP Partners executed a series of derivative instruments to mitigate a portion of its anticipated commodity exposure. DCP Partners entered into natural gas swap contracts for 2,000 MMBtu/d at $7.80/MMBtu, for a term from July through December 2008, and DCP Partners entered into crude oil swap contracts, each for 225 Bbls/d at an average of $87.93/Bbl, for terms ranging from July 2008 through December 2012.

On March 17, 2008, DCP Partners closed an offering of 4,250,000 of its common units representing limited partner interests at $32.44 per unit.

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DCP MIDSTREAM, LLC

SCHEDULE II — CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS AND RESERVES FOR THE YEARS ENDED DECEMBER 31, 2007, 2006 AND 2005

	Balance at Beginning of Period	Charged to Consolidated Statements of Operations	Charged to Other Accounts (b) (Millions)	Deductions (c)	Balance at End of Period
December 31, 2007					
Allowance for doubtful accounts	$ 3	$ 2	$ 1	$ (1)	$ 5
Environmental	12	2	2	(4)	12
Litigation	9	9	—	(3)	15
Other (a)	4	—	—	(1)	3
	$ 28	$ 13	$ 3	$ (9)	$ 35
December 31, 2006					
Allowance for doubtful accounts	$ 4	$ —	$ —	$ (1)	$ 3
Environmental	13	3	—	(4)	12
Litigation	5	6	—	(2)	9
Other (a)	6	—	—	(2)	4
	$ 28	$ 9	$ —	$ (9)	$ 28
December 31, 2005					
Allowance for doubtful accounts	$ 4	$ 1	$ —	$ (1)	$ 4
Environmental	17	5	—	(9)	13
Litigation	8	1	2	(6)	5
Other (a)	8	11	(2)	(11)	6
	$ 37	$ 18	$ —	$ (27)	$ 28

(a) Principally consists of other contingency reserves, which are included in other current liabilities.
(b) Consists of purchase accounting adjustments for the Momentum Energy Group, Inc. acquisition in 2007 and other contingency and litigation reserves reclassified between accounts in 2005.
(c) Principally consists of cash payments, collections, reserve reversals and liabilities settled.

Section 2: EX-23.1 (CONSENT OF INDEPENDENT AUDITORS)

EXHIBIT 23.1

CONSENT OF INDEPENDENT AUDITORS

We consent to the incorporation by reference in Registration Statement Nos. 333-140048, 333-140049 and 333-141982 on Form S-3 and Registration Statement Nos. 333-139661 and 333-149106 on Form S-8 of Spectra Energy Corp of our report dated March 7, 2008 (March 20, 2008 as to the offering described in Note 19), relating to the consolidated financial statements and financial statement schedule of DCP Midstream, LLC and subsidiaries as of December 31, 2007 and 2006, and for each of the three years in the period ended December 31, 2007, appearing in Amendment No. 1 to this Annual Report on Form 10-K of Spectra Energy Corp for the year ended December 31, 2007.

/s/ Deloitte & Touche LLP

Denver, Colorado
March 20, 2008

Section 3: EX-31.1 (SECTION 302 CERTIFICATION OF CEO)

EXHIBIT 31.1

**CERTIFICATION OF THE CHIEF EXECUTIVE OFFICER
PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002**

I, Fred J. Fowler, certify that:

1) I have reviewed this Amendment No. 1 to the annual report on Form 10-K/A of Spectra Energy Corp;
2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

Date: March 20, 2008

/s/ Fred J. Fowler
Fred J. Fowler
President and Chief Executive Officer

Section 4: EX-31.2 (SECTION 302 CERTIFICATION OF CFO)

EXHIBIT 31.2

**CERTIFICATION OF THE CHIEF FINANCIAL OFFICER
PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002**

I, Gregory L. Ebel, certify that:

1) I have reviewed this Amendment No. 1 to the annual report on Form 10-K/A of Spectra Energy Corp;
2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

Date: March 20, 2008

/s/ Gregory L. Ebel
Gregory L. Ebel
Group Executive and Chief Financial Officer

Section 5: EX-32.1 (SECTION 906 CERTIFICATION OF CEO)

EXHIBIT 32.1

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Amendment No. 1 to the Annual Report of Spectra Energy Corp on Form 10-K/A for the period ending December 31, 2007 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Fred J. Fowler, President and Chief Executive Officer of Spectra Energy Corp, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Spectra Energy Corp.

Date: March 20, 2008

/s/ Fred J. Fowler
Fred J. Fowler
President and Chief Executive Officer

Section 6: EX-32.2 (SECTION 906 CERTIFICATION OF CFO)

EXHIBIT 32.2

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Amendment No. 1 to the Annual Report of Spectra Energy Corp on Form 10-K/A for the period ending December 31, 2007 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Gregory L. Ebel, Group Executive and Chief Financial Officer of Spectra Energy Corp, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Spectra Energy Corp.

Date: March 20, 2008

/s/ Gregory L. Ebel
Gregory L. Ebel
Group Executive and Chief Financial Officer

10-Q 1 suform10q_93008.htm SOUTHERN UNION COMPANY FORM 10-Q, SEPTEMBER 30, 2008

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D. C. 20549

FORM 10-Q

Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the quarterly period ended

September 30, 2008

Commission File No. 1-6407

SOUTHERN UNION COMPANY

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**75-0571592** (I.R.S. Employer Identification No.)
5444 Westheimer Road **Houston, Texas** (Address of principal executive offices)	**77056-5306** (Zip Code)

Registrant's telephone number, including area code: **(713) 989-2000**

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exc Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has subject to such filing requirements for the past 90 days.
Yes **P** No___

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):
Large accelerated filer **P** Accelerated filer _ Non-accelerated filer _ (Do not check if smaller reporting company) Smaller reporting company ____ _ _

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes ___ No **P**

The number of shares of the registrant's Common Stock outstanding on October 31, 2008 was 123,982,918.

SOUTHERN UNION COMPANY AND SUBSIDIARIES
FORM 10-Q
September 30, 2008
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GLOSSARY

The abbreviations, acronyms and industry terminology used in this quarterly report on Form 10-Q are defined as follows:

AAD	Administrative Adjudication Division
AFUDC	Allowance for funds used during construction
CEO	Chief Executive Officer
CFO	Chief Financial Officer
Citrus	Citrus Corp.
EBIT	Earnings before interest and taxes
EITR	Effective income tax rate
EPA	Environmental Protection Agency
Exchange Act	Securities Exchange Act of 1934
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FDOT/FTE	Florida Department of Transportation, Florida's Turnpike Enterprise
Florida Gas	Florida Gas Transmission Company, LLC
GAAP	Accounting principles generally accepted in the United States of America
Grey Ranch	Grey Ranch Plant, LP
IEPA	Illinois Environmental Protection Agency
IPCB	Illinois Pollution Control Board
IRS	Internal Revenue Service
KDHE	Kansas Department of Health and Environment
LNG	Liquified natural gas
LNG Holdings	Trunkline LNG Holdings, LLC
MDEP	Massachusetts Department of Environmental Protection
MDPU	Massachusetts Department of Public Utilities
MGPs	Manufactured gas plants
MMBtu	Million British thermal units
MMcf/d	Million cubic feet per day
MPSC	Missouri Public Service Commission
NGL	Natural gas liquids
Panhandle	Panhandle Eastern Pipe Line Company, LP and its subsidiaries
PCBs	Polychlorinated biphenyls
PEPL	Panhandle Eastern Pipe Line Company, LP
PRPs	Potentially responsible parties
RCRA	Resource Conservation and Recovery Act
RIDEM	Rhode Island Department of Environmental Management
SARs	Stock appreciation rights
Sea Robin	Sea Robin Pipeline Company, LLC
SEC	Securities and Exchange Commission
Southern Union	Southern Union Company
Southwest Gas	Pan Gas Storage, LLC (d.b.a. Southwest Gas)
SPCC	Spill Prevention, Control and Countermeasure
SUGS	Southern Union Gas Services
TBtu	Trillion British thermal units
TCEQ	Texas Commission on Environmental Quality
Trunkline	Trunkline Gas Company, LLC
Trunkline LNG	Trunkline LNG Company, LLC

PART I. FINANCIAL INFORMATION
ITEM 1. FINANCIAL STATEMENTS (UNAUDITED)

SOUTHERN UNION COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENT OF OPERATIONS
(UNAUDITED)

	Three months ended September 30,		Nine months ended September 30,	
	2008	2007	2008	2007
	(In thousands, except per share amounts)			
Operating revenues (Note 11)	$ 657,283	$ 525,473	$ 2,343,036	$ 1,893,754
Operating expenses:				
Cost of gas and other energy	361,970	261,324	1,431,171	1,069,035
Operating, maintenance and general	131,076	108,478	356,265	318,982
Depreciation and amortization	50,049	44,900	147,993	132,030
Revenue-related taxes	4,736	3,804	29,660	26,498
Taxes, other than on income and revenues	12,172	9,987	36,835	33,235
Total operating expenses	560,003	428,493	2,001,924	1,579,780
Operating income	97,280	96,980	341,112	313,974
Other income (expenses):				
Interest expense	(53,232)	(50,703)	(154,536)	(154,034)
Earnings from unconsolidated investments	21,624	24,820	59,451	81,986
Other, net	769	(1,961)	1,827	1,800
Total other income (expenses), net	(30,839)	(27,844)	(93,258)	(70,248)
Earnings before income taxes	66,441	69,136	247,854	243,726
Federal and state income tax expense (Note 9)	19,665	23,853	75,260	68,747
Net earnings	46,776	45,283	172,594	174,979
Preferred stock dividends	(2,264)	(4,342)	(10,041)	(13,024)
Loss on extinguishment of preferred stock (Note 14)	(2,036)	-	(4,031)	-
Net earnings available for common stockholders	$ 42,476	$ 40,941	$ 158,522	$ 161,955
Net earnings available for common stockholders per share:				
Basic	$ 0.34	$ 0.34	$ 1.29	$ 1.35
Diluted	0.34	0.34	1.28	1.34
Dividends declared on common stock per share	$ 0.15	$ 0.10	$ 0.45	$ 0.30
Weighted average shares outstanding (Note 5):				
Basic	123,975	120,018	123,264	119,894
Diluted	124,205	120,759	123,523	120,622

The accompanying notes are an integral part of these condensed consolidated financial statements.

Docket No. RP09-_____-000
Exhibit No. HIO-74
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SOUTHERN UNION COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEET
(UNAUDITED)

ASSETS

	September 30, 2008	December 31, 2007
	(In thousands)	
Current assets:		
Cash and cash equivalents	$ 3,060	$ 5,690
Accounts receivable, net of allowances of $7,573 and $4,144, respectively	193,246	358,521
Accounts receivable – affiliates	49,222	29,943
Inventories (Note 4)	344,084	263,618
Deferred gas purchases	52,408	3,496
Gas imbalances - receivable	186,477	105,371
Prepayments and other assets	45,989	41,685
Total current assets	874,486	808,324
Property, plant and equipment:		
Plant in service	5,902,840	5,509,992
Construction work in progress	415,387	377,918
	6,318,227	5,887,910
Less accumulated depreciation and amortization	(928,710)	(785,623)
Net property, plant and equipment	5,389,517	5,102,287
Deferred charges:		
Regulatory assets	69,425	64,193
Deferred charges	66,649	60,468
Total deferred charges	136,074	124,661
Unconsolidated investments (Note 6)	1,243,639	1,240,420
Goodwill	89,227	89,227
Other	28,695	32,994
Total assets	$ 7,761,638	$ 7,397,913

The accompanying notes are an integral part of these condensed consolidated financial statements.

SOUTHERN UNION COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEET
(UNAUDITED)

STOCKHOLDERS' EQUITY AND LIABILITIES

	September 30, 2008	December 31, 2007
	(In thousands)	
Stockholders' equity:		
Common stock, $1 par value; 200,000 shares authorized; 125,103 and 121,102 shares issued, respectively	$ 125,103	$ 121,102
Preferred stock, no par value; 6,000 shares authorized; 480 and 920 shares issued, respectively (Note 14)	119,973	230,000
Premium on capital stock	1,891,946	1,784,223
Less treasury stock: 1,120 and 1,063 shares, respectively, at cost	(28,005)	(27,839)
Less common stock held in trust: 652 and 783 shares, respectively	(11,703)	(15,085)
Deferred compensation plans	11,703	15,148
Accumulated other comprehensive loss	(3,176)	(11,594)
Retained earnings	212,589	109,851
Total stockholders' equity	2,318,430	2,205,806
Long-term debt obligations (Note 7)	3,254,877	2,960,326
Total capitalization	5,573,307	5,166,132
Current liabilities:		
Long-term debt due within one year (Note 7)	60,888	434,680
Notes payable	377,246	123,000
Accounts payable and accrued liabilities	226,313	335,253
Federal, state and local taxes payable	36,473	35,461
Accrued interest	56,277	45,911
Customer deposits	11,067	17,589
Gas imbalances - payable	316,987	272,850
Other	137,965	58,969
Total current liabilities	1,223,216	1,323,713
Deferred credits	205,522	215,063
Accumulated deferred income taxes	759,593	693,005
Commitments and contingencies (Note 10)		
Total stockholders' equity and liabilities	$ 7,761,638	$ 7,397,913

The accompanying notes are an integral part of these condensed consolidated financial statements.

Docket No. RP09-_____-000
Exhibit No. HIO-74
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Docket No. RP09-_____-000
Exhibit No. HIO-74
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SOUTHERN UNION COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENT OF CASH FLOWS
(UNAUDITED)

	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
	(In thousands)	
Cash flows provided by (used in) operating activities:		
Net earnings	$ 172,594	$ 174,979
Adjustments to reconcile net earnings to net cash flows provided by operating activities:		
Depreciation and amortization	147,993	132,030
Deferred income taxes	68,871	50,808
Unrealized loss on derivatives	5,387	1,227
Earnings from unconsolidated investments, adjusted for cash distributions	(18,701)	11,889
Provision for bad debts	18,344	13,574
Other	16,435	2,231
Changes in operating assets and liabilities	(37,481)	1,982
Net cash flows provided by operating activities	373,442	388,720
Cash flows provided by (used in) investing activities:		
Additions to property, plant and equipment	(482,121)	(382,123)
Dispositions of operations, net	-	(49,304)
Return of investment in Citrus (Note 6)	-	9,674
Plant retirements and other	16,581	3,501
Net cash flows used in investing activities	(465,540)	(418,252)
Cash flows provided by (used in) financing activities:		
Decrease in book overdraft	(9,110)	(2,139)
Issuance costs of debt	(4,145)	(2,418)
Issuance of common stock	100,000	-
Issuance of long-term debt	400,860	455,000
Dividends paid on common stock	(55,185)	(35,933)
Dividends paid on preferred stock	(12,118)	(13,024)
Extinguishment of preferred stock	(110,905)	-
Repayment of debt obligations	(476,829)	(493,316)
Net change in revolving credit facilities	254,246	130,000
Proceeds from exercise of stock options	3,960	3,592
Other	(1,306)	1,758
Net cash flows provided by (used in) financing activities	89,468	43,520
Change in cash and cash equivalents	(2,630)	13,988
Cash and cash equivalents at beginning of period	5,690	5,751
Cash and cash equivalents at end of period	$ 3,060	$ 19,739

The accompanying notes are an integral part of these condensed consolidated financial statements.

SOUTHERN UNION COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY AND COMPREHENSIVE INCOME
(UNAUDITED)

	Common Stock, $1 Par Value	Preferred Stock, No Par Value	Premium on Capital Stock	Treasury Stock, at cost	Common Stock Held In Trust	Deferred Compensation Plans	Accumulated Other Comprehensive Loss	Retained Earnings	Total Stockholders' Equity
					(In thousands)				
Balance December 31, 2007	$ 121,102	$ 230,000	$1,784,223	$ (27,839)	$ (15,085)	$ 15,148	$ (11,594)	$ 109,851	$2,205,806
Comprehensive income:									
Net earnings	-	-	-	-	-	-	-	172,594	172,594
Net change in other comprehensive loss (Note 3)	-	-	-	-	-	-	8,418	-	8,418
Comprehensive income									181,012
Preferred stock dividends	-	-	-	-	-	-	-	(10,041)	(10,041)
Cash dividends declared	-	-	-	-	-	-	-	(55,784)	(55,784)
Issuance of common stock - remarketing obligation (Note 7)	3,693	-	96,307	-	-	-	-	-	100,000
Share-based compensation	-	-	4,611	-	-	-	-	-	4,611
Restricted stock issuances	71	-	(71)	(166)	-	-	-	-	(166)
Exercise of stock options	237	-	3,723	-	-	-	-	-	3,960
Extinguishment of preferred stock (Note 14)	-	(110,027)	3,153	-	-	-	-	(4,031)	(110,905)
Contributions to Trust	-	-	-	-	(884)	884	-	-	-
Disbursements from Trust and other	-	-	-	-	4,266	(4,329)	-	-	(63)
Balance September 30, 2008	$ 125,103	$ 119,973	$1,891,946	$ (28,005)	$ (11,703)	$ 11,703	$ (3,176)	$ 212,589	$2,318,430

The Company's common stock is $1 par value. Therefore, the change in *Common Stock, $1 par value,* is equivalent to the change in the number of shares of common stock issued.

The accompanying notes are an integral part of these condensed consolidated financial statements.

SOUTHERN UNION COMPANY AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

The accompanying unaudited interim condensed consolidated financial statements of Southern Union and its subsidiaries (collectively, *the Company*) have been prepared pursuant to the rules and regulations of the SEC for quarterly reports on Form 10-Q. These statements do not include all of the information and annual note disclosures required by GAAP, and should be read in conjunction with the Company's financial statements and notes thereto for the year ended December 31, 2007, which are included in the Company's Form 10-K filed with the SEC. The accompanying unaudited interim condensed consolidated financial statements have been prepared in accordance with GAAP and reflect adjustments that are, in the opinion of management, necessary for a fair statement of results for the interim period. The year-end condensed balance sheet data was derived from audited financial statements, but does not include all disclosures required by GAAP. Due to the seasonal nature of the Company's operations, the results of operations and cash flows for any interim period are not necessarily indicative of the results that may be expected for the full year.

1. Description of Business

Southern Union owns and operates assets in the regulated and unregulated natural gas industry and is primarily engaged in the gathering, processing, transportation, storage and distribution of natural gas in the United States. The Company operates in three reportable segments: Transportation and Storage, Gathering and Processing, and Distribution. The Transportation and Storage segment is primarily engaged in the interstate transportation and storage of natural gas in the Midwest and from the Gulf Coast to Florida, and also provides LNG terminalling and regasification services. The Gathering and Processing segment is primarily engaged in the gathering, treating, processing and redelivery of natural gas and NGL in Texas and New Mexico. The Distribution segment is primarily engaged in the local distribution of natural gas in Missouri and Massachusetts.

2. New Accounting Principles

Accounting Principles Recently Adopted.

FASB Statement No. 157, "Fair Value Measurements" (Statement No. 157): Issued by the FASB in September 2006, this Statement defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. Where applicable, this Statement simplifies and codifies related guidance within GAAP. This Statement is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. In February 2008, the FASB released a FASB Staff Position (FSP FAS 157-2, "*Effective Date of FASB Statement No. 157*"), which delays the effective date of this Statement for all non-financial assets and non-financial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually), to fiscal years beginning after November 15, 2008. The Company's major categories of non-financial assets and non-financial liabilities that are

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recognized or disclosed at fair value for which, in accordance with FSP FAS 157-2, the Company has not applied the provisions of Statement No. 157 as of January 1, 2008 are (i) fair value calculations associated with annual or periodic impairment tests, and (ii) asset retirement obligations measured at fair value upon initial recognition or upon certain remeasurement events under FASB Statement No. 143, "*Accounting for Asset Retirement Obligations*." The partial adoption on January 1, 2008 of this Statement for financial assets and liabilities did not have a material impact on the Company's consolidated financial statements. See *Note 12 – Fair Value Measurement* for more information. In October 2008, the FASB issued FASB Staff Position FSP FAS 157-3, "*Determining the Fair Value of a Financial Asset When the Market for that Asset is Not Active*" (*FSP FAS 157-3*). FSP FAS 157-3 provides clarifying guidance with respect to the application of Statement No. 157 in determining the fair value of a financial asset when the market for that asset is not active. FSP FAS 157-3 was effective upon its issuance. The application of FSP FAS 157-3 did not have a material impact on the Company's consolidated financial statements.

FASB Statement No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities – Including an Amendment of FASB Statement No. 115": Issued by the FASB in February 2007, this Statement permits entities to choose to measure many financial instruments and certain other items at fair value that are not currently required to be measured at fair value. Unrealized gains and losses on items for which the fair value option has been elected are reported in earnings. The Statement does not affect any existing accounting literature that requires certain assets and liabilities to be carried at fair value. The Statement is effective for fiscal years beginning after November 15, 2007. At January 1, 2008, the Company did not elect the fair value option under the Statement and, therefore, there was no impact on the Company's consolidated financial statements.

Staff Accounting Bulletin No. 110 (SAB 110): Issued by the SEC in December 2007, SAB 110 expresses the views of the SEC staff regarding the use of a "simplified" method, as discussed in SAB No. 107, in developing an estimate of expected term of "plain vanilla" share options in accordance with Statement No. 123R, "*Accounting for Stock-Based Compensation*." The SEC staff indicated in SAB No. 107 that it would accept a company's election to use the simplified method, regardless of whether the company has sufficient information to make more refined estimates of expected term, for options granted prior to December 31, 2007. In SAB 110, the SEC staff states that it will continue to accept, under certain circumstances, the use of the simplified method beyond December 31, 2007. Pursuant to the guidance provided in SAB 110, the Company has elected to continue utilizing the simplified method in developing the estimate of the expected term for its share options.

FSP No. FIN 39-1, "Amendment of FASB Interpretation No. 39" (FIN 39-1): Issued by the FASB in April 2007, FIN 39-1 impacts entities that enter into master netting arrangements as part of their derivative transactions by allowing net derivative positions to be offset in the financial statements against the fair value of amounts (or amounts that approximate fair value) recognized for the right to reclaim cash collateral or the obligation to return cash collateral under those arrangements. In accordance with FASB Interpretation No. 39, the Company has historically offset the fair value amounts for derivative instruments executed with the same counterparty where a right of setoff existed, which included derivative instruments subject to master netting arrangements at December 31, 2007. In accordance with FIN 39-1, the Company elects to offset the fair value amounts for derivative instruments, including cash collateral, executed with the same counterparty under a master netting arrangement.

Accounting Principles Not Yet Adopted.

FASB Statement No. 141 (revised), "Business Combinations" (SFAS 141). Issued by the FASB in December 2007, this Statement changes the accounting for business combinations including the measurement of acquirer shares issued in consideration of a business combination, the recognition of contingent consideration, the accounting for preacquisition gain and loss contingencies, the recognition of capitalized in-process research and development costs, the accounting for acquisition-related restructuring cost accruals, the treatment of acquisition-related transaction costs and the recognition of changes in the acquirer's income tax valuation allowance. The Statement is effective for fiscal years beginning after December 15, 2008, with early adoption prohibited.

FASB Statement No. 160, "Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51". Issued by the FASB in December 2007, this Statement changes the accounting for noncontrolling (minority) interests in consolidated financial statements, including the requirements to classify noncontrolling interests as a component of consolidated stockholders' equity, and the elimination of minority interest accounting in results of operations with earnings attributable to noncontrolling interests reported as part of consolidated earnings. Additionally, the Statement revises the accounting for both increases and decreases in a parent's controlling ownership interest. The Statement is effective for fiscal years beginning after December 15, 2008, with early adoption prohibited. The Company is currently evaluating the impact of this Statement on its consolidated financial statements.

FASB Statement No. 161, "Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133". Issued by the FASB in March 2008, this Statement requires disclosure of how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for and how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. The Statement is effective for fiscal years beginning after November 15, 2008, with early adoption permitted. The Company is currently evaluating the impact of this Statement on its consolidated financial statements.

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3. Comprehensive Income (Loss)

The table below provides an overview of *Comprehensive income (loss)* for the periods indicated:

Comprehensive Income (Loss)	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
	(In thousands)			
Net Earnings	$ 46,776	$ 45,283	$ 172,594	$ 174,979
Comprehensive Income (Loss) Adjustments:				
Change in fair value of interest rate hedges, net of tax of $(2,096), $(4,329), $(3,090) and $(1,374), respectively	(3,118)	(6,319)	(4,523)	(1,924)
Reclassification of unrealized (gain) loss on interest rate hedges into earnings, net of tax of $1,280, $(34), $2,978 and $115, respectively	1,940	(143)	4,537	(946)
Realized loss on interest rate hedges, net of tax of $0, $0, $(620) and $0, respectively	-	-	(1,175)	-
Change in fair value of commodity hedges, net of tax of $21,257, $1,156, $7,006 and $(828), respectively	37,724	1,906	12,434	(1,364)
Reclassification of unrealized (gain) loss on commodity hedges into earnings, net of tax of $(268), $(829), $1,352 and $(2,004), respectively	(475)	(1,366)	2,399	(3,303)
Reduction of prior service credit relating to pension and other postretirement benefits, net of tax of $0, $0, $(3,231) and $0, respectively	-	-	(6,603)	-
Reclassification of net actuarial (gain) loss and prior service credit relating to pension and other postretirement benefits into earnings, net of tax of $(30), $(880), $921 and $(381), respectively	(110)	(1,341)	1,349	(158)
Total other comprehensive income (loss)	35,961	(7,263)	8,418	(7,695)
Total comprehensive income	$ 82,737	$ 38,020	$ 181,012	$ 167,284

See *Note 8 – Employee Benefits* for a discussion related to an amendment of Panhandle's other postretirement benefit plans in March 2008, which resulted in a $6.6 million net of tax reduction in the net prior service credit included in *Accumulated other comprehensive loss*.

4. Inventories

In the Transportation and Storage segment, inventories consist of natural gas held for operations and materials and supplies, both of which are stated at the lower of weighted average cost or market, while gas received from or owed back to customers is valued at market. The gas held for operations that the Company does not expect to consume in its operations in the next twelve months is reflected in non-current assets.

In the Gathering and Processing segment, inventories consist of non-fractionated Y-grade NGL and materials and supplies, both of which are stated at the lower of weighted average cost or market. With respect to information regarding the increase in SUGS' NGL inventory resulting from hurricane damage to a third-party NGL fractionator, see *Note 10 – Commitments and Contingencies – Other Commitments and Contingencies – 2008 Hurricane Damage*. Materials and supplies are primarily comprised of compressor components and parts.

In the Distribution segment, inventories consist of natural gas in underground storage and materials and supplies, both of which are stated at weighted average cost.

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The components of inventory at the dates indicated are as follows:

	Transportation & Storage	Gathering & Processing	Distribution	Total
		(In thousands)		
At September 30, 2008				
Current				
Natural gas held for operations (1)	$ 140,870	$ -	$ -	$ 140,870
Materials and Supplies	13,602	9,550	4,357	27,509
NGL (2)	-	4,336	-	4,336
Natural gas in underground storage (3)	-	-	171,369	171,369
Total Current	154,472	13,886	175,726	344,084
Non-Current				
Natural gas held for operations (1)	15,542	-	-	15,542
	$ 170,014	$ 13,886	$ 175,726	$ 359,626
At December 31, 2007				
Current				
Natural gas held for operations (1)	$ 168,010	$ -	$ -	$ 168,010
Materials and Supplies	12,791	6,176	3,822	22,789
Natural gas in underground storage (3)	-	-	72,819	72,819
Total Current	180,801	6,176	76,641	263,618
Non-Current				
Natural gas held for operations (1)	18,947	-	-	18,947
	$ 199,748	$ 6,176	$ 76,641	$ 282,565

(1) Natural gas volumes held for operations at September 30, 2008 and December 31, 2007 were 20,333,000 MMBtu and 26,001,000 MMBtu, respectively.
(2) NGL at September 30, 2008 and December 31, 2007 was 4,568,000 gallons and nil, respectively.
(3) Natural gas volumes in underground storage at September 30, 2008 and December 31, 2007 were 17,406,000 MMBtu and 11,823,000 MMBtu, respectively.

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5. Earnings per Share

Basic earnings per share is computed based on the weighted average number of common shares outstanding during each period. Diluted earnings per share is computed based on the weighted average number of common shares outstanding during each period, increased by conversion of equity units and common stock equivalents from stock options, restricted stock and SARs. A reconciliation of the shares used in the basic and diluted earnings per share calculations is shown in the following table.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
	(In thousands)			
Weighted average shares outstanding - Basic	123,975	120,018	123,264	119,894
Add assumed vesting of restricted stock	29	41	14	30
Add assumed conversion of equity units	-	270	-	227
Add assumed exercise of stock options and SARs	201	430	245	471
Weighted average shares outstanding - Diluted	124,205	120,759	123,523	120,622

The table below includes information related to stock options and SARs that were outstanding but have been excluded from the computation of weighted-average stock options due to the exercise price exceeding the weighted-average market price of the Company's common shares.

	September 30,	
	2008	2007
	(In thousands, except per share amounts)	
Options excluded	717	-
Exercise price of options excluded	$ 28.48	N/A
SARs excluded	416	-
Exercise price ranges of SARs excluded	$ 28.07 - $28.48	N/A
Third quarter weighted-average market price	$ 24.91	$ 30.96
Year-to-date weighted-average market price	$ 25.67	$ 30.55

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6. Unconsolidated Investments

A summary of the Company's unconsolidated equity investments at the dates indicated is as follows:

	September 30, 2008	December 31, 2007
	(In thousands)	
Citrus	$ 1,223,059	$ 1,219,009
Other	20,580	21,411
	$ 1,243,639	$ 1,240,420

Unconsolidated equity investments at September 30, 2008 and December 31, 2007 included the Company's 50 percent, 50 percent, 29 percent and 49.9 percent investments in Citrus, Grey Ranch, Lee 8 Partnership and PEI II, LLC, respectively. The Company accounts for these investments using the equity method. The Company's share of net earnings or loss from these equity investments is recorded in *Earnings from unconsolidated investments* in the unaudited interim Condensed Consolidated Statement of Operations.

Summarized financial information for the Company's equity investments is as follows:

	September 30,2008		September 30,2007	
	Citrus	Other	Citrus	Other
	(In thousands)			
Three Months Ended:				
Revenues	$ 139,513	$ 2,593	$ 136,800	$ 4,115
Operating income	81,080	(320)	84,686	1,554
Net earnings (losses)	38,609	(642)	42,177	1,532
Nine Months Ended:				
Revenues	$ 386,738	$ 10,603	$ 375,357	$ 8,848
Operating income	218,017	1,637	218,132	2,879
Net earnings	102,246	534	126,438	3,725

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Citrus.

Dividends. During the three- and nine-month periods ended September 30, 2008, Citrus paid dividends of nil and $40.8 million, respectively, to the Company. In the three- and nine-month periods ended September 30, 2007, Citrus paid dividends of $27.4 million and $103.6 million, respectively, to the Company, of which $9.7 million has been reflected by the Company as a return of investment. Citrus also declared a dividend in September 2008, payable in October 2008, of which the Company's share is $36.4 million.

Phase VIII Expansion. Florida Gas, a wholly-owned subsidiary of Citrus, filed a certificate application on October 31, 2008 with FERC to construct an expansion to increase its natural gas capacity into Florida by approximately 820 MMcf/d (*Phase VIII Expansion*). The proposed Phase VIII Expansion includes construction of approximately 500 miles of large diameter pipeline and the installation of approximately 200,000 horsepower of compression. Pending FERC approval, which is expected in the latter half of 2009, Florida Gas anticipates an in-service date during 2011, at a currently estimated cost of approximately $2.4 billion, including capitalized equity and debt costs. To date, Florida Gas has entered into precedent agreements with shippers for transportation services for 25-year terms accounting for approximately 89 percent of the available expansion capacity.

On February 5, 2008, Citrus entered into a $500 million unsecured construction and term loan agreement (*Construction Loan Agreement*) with a wholly-owned subsidiary of FPL Group Capital Inc., which is a wholly-owned subsidiary of FPL Group, Inc. Citrus will primarily invest the proceeds of this loan into Florida Gas in order to finance a portion of the Phase VIII Expansion. On August 6, 2008, the parties amended the Construction Loan Agreement to accelerate the funding date to October 1, 2008. On October 1, 2008, Citrus borrowed all of the $500 million available under the Construction Loan Agreement.

Florida Gas Pipeline Relocation Costs. The FDOT/FTE has various turnpike widening projects that have or may, over time, impact one or more of Florida Gas' mainline pipelines located in FDOT/FTE rights-of-way. Under certain conditions, existing agreements between Florida Gas and the FDOT/FTE require the FDOT/FTE to provide any new rights-of-way needed for relocation of the pipelines and Florida Gas to pay for rearrangement or relocation costs. Under certain other conditions, Florida Gas may be entitled to reimbursement for the costs associated with relocation, including construction and rights-of-way costs.

On October 20, 2005, Florida Gas filed an application with FERC for a State Road 91 Relocation Project. The first phase of the turnpike project included replacement of approximately 11.3 miles of its existing 18- and 24-inch pipelines located in FDOT/FTE rights-of-way in Broward County, Florida to accommodate the widening of State Road 91 by the FDOT/FTE. The FERC issued an order approving the project on May 3, 2006, and Florida Gas notified the FERC that construction commenced on April 25, 2007. Florida Gas received authorization from the FERC to place the facilities in service on March 20, 2008 and the State Road 91 Relocation facilities were placed in service on the same day. Approximately $111 million of replacement costs have been incurred as of September 30, 2008. As of September 30, 2008, no pipeline removal costs associated with the State Road 91 Relocation Project have been incurred.

On May 2, 2008, Florida Gas filed with FERC an amendment to its existing certificate seeking to hold in abeyance the abandonment authorization of the 18- and 24-inch existing pipelines for up to three years as a result of actions by the FDOT/FTE. On June 16, 2008, the FDOT/FTE intervened in the proceeding before FERC regarding the first phase of the project seeking an order from FERC to force Florida Gas to abandon and decommission the 18- and 24-inch pipelines. In an order issued October 10, 2008, FERC denied the amendment filed by Florida Gas and ordered Florida Gas to remove the 18- and 24-inch pipelines from service in accordance with a prior order. Florida Gas is also in discussions with the FDOT/FTE related to additional projects that may affect Florida Gas' 18- and 24-inch pipelines within FDOT/FTE rights-of-way. The total miles of pipe that may ultimately be affected by all of the FDOT/FTE widening projects, and any associated relocation and/or rights-of-way costs, cannot be determined at this time.

The various FDOT/FTE projects have also been the subject of state court litigation. On January 25, 2007, Florida Gas filed a complaint against FDOT/FTE in the Seventeenth Judicial Circuit, Broward County, Florida, to seek relief for three specific sets of FDOT/FTE widening projects in Broward County. The complaint seeks damages for breach of easement and relocation agreements for the State Road 91 Relocation Project and injunctive relief as well as damages for the two other sets of projects upon which construction has yet to commence. The FDOT/FTE filed an amended answer

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and counterclaim against Florida Gas on February 5, 2008 in the Broward County action. The counterclaim alleges Florida Gas is subject to estoppel and breach of contract claims regarding removal from service of the existing 18- and 24-inch pipelines related to the State Road 91 Relocation Project and seeks a declaratory judgment that Florida Gas is responsible for all relocation costs and is not entitled to workspace and uniform minimum area with respect to its pipelines. On February 14, 2008 the case was transferred to the Broward County Complex Business Civil Division 07. On April 14, 2008, the FDOT/FTE amended its counterclaim, alleging Florida Gas committed fraud in the inducement by not removing its previously existing pipelines, seeking to place a constructive trust over any revenues associated with the previously existing and newly constructed pipelines, seeking a declaratory order from the Court that Florida Gas has abandoned its previously existing pipelines and seeking a temporary and permanent injunction forcing Florida Gas to remove such pipelines. On July 21, 2008, the Court allowed the FDOT/FTE to further amend its counterclaim to include counts of fraud and trespass but reserved ruling on permitting a demand for punitive damages on those counts. On October 6, 2008, the FDOT/FTE filed a supplemental motion for temporary injunction and a motion for partial summary judgment against Florida Gas on the extent of the rights Florida Gas claims under the easements at issue, the breach of the easements by the FDOT/FTE for failing to provide adequate rights-of-way, the failure of the FDOT/FTE to reimburse Florida Gas for the costs of relocation, and inverse condemnation by the FDOT/FTE as a result of the breach of the easements. Trial is scheduled for August 2009. A 2007 action brought by the FDOT/FTE against Florida Gas in Orange County, Florida, seeking a declaratory judgment that, under existing agreements, Florida Gas is liable for the costs of relocation associated with FDOT/FTE projects, has been stayed pending resolution of the Broward County, Florida action.

Should Florida Gas be denied reimbursement by the FDOT/FTE for relocation expenses, such costs are expected to be covered by operating cash flows and additional borrowings. Florida Gas expects to seek rate recovery at FERC for all reasonable and prudent costs incurred in relocating its pipelines to accommodate the FDOT/FTE to the extent not reimbursed by the FDOT/FTE. There can be no assurance that Florida Gas will be successful in obtaining complete reimbursement for any such relocation costs from the FDOT/FTE or from its customers or that the timing of reimbursement will fully compensate Florida Gas for its costs.

Litigation.

Jack Grynberg. Jack Grynberg, an individual, filed actions for damages against a number of companies, including Florida Gas, alleging mis-measurement of gas volumes and Btu content, resulting in lower royalties to mineral interest owners. For additional information related to these filed actions, see *Note 10 – Commitments and Contingencies – Litigation.*

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7. Debt Obligations

The following table sets forth the debt obligations of Southern Union and applicable units of Panhandle under their respective notes, debentures and bonds at the dates indicated:

	September 30, 2008	December 31, 2007
	(In thousands)	
Long-Term Debt Obligations:		
Southern Union		
7.60% Senior Notes due 2024	$ 359,765	$ 359,765
8.25% Senior Notes due 2029	300,000	300,000
7.24% to 9.44% First Mortgage Bonds due 2020 to 2027	19,500	19,500
4.375% Senior Notes due 2008	-	100,000
6.15% Senior Notes due 2008	-	125,000
6.089% Senior Notes due 2010	100,000	-
7.20% Junior Subordinated Notes due 2066	600,000	600,000
Note Payable	860	-
	1,380,125	1,504,265
Panhandle		
4.80% Senior Notes due 2008	-	300,000
6.05% Senior Notes due 2013	250,000	250,000
6.20% Senior Notes due 2017	300,000	300,000
6.50% Senior Notes due 2009	60,623	60,623
8.25% Senior Notes due 2010	40,500	40,500
7.00% Senior Notes due 2029	66,305	66,305
7.00% Senior Notes due 2018	400,000	-
Term Loans due 2012	815,391	867,220
Net premiums on long-term debt	2,821	6,093
	1,935,640	1,890,741
Total Long-Term Debt Obligations	3,315,765	3,395,006
Credit Facilities	377,246	123,000
Total consolidated debt obligations	3,693,011	3,518,006
Less current portion of long-term debt	60,888	434,680
Less short-term debt	377,246	123,000
Total consolidated long-term debt obligations	$ 3,254,877	$ 2,960,326

Short-Term Facility. On August 11, 2008, Southern Union entered into a short-term Credit Agreement in the amount of $150 million (*Short-Term Facility*). The Short-Term Facility is a 364-day term loan facility and will be due in its entirety on August 10, 2009. The interest rate associated with the Short-Term Facility is based, at the Company's option, upon either LIBOR plus 125 basis points or the prime lending rate. Borrowings under the Short-Term Facility are available for general corporate purposes. On October 1, 2008, Southern Union borrowed the $150 million and used the proceeds to reduce the amounts outstanding under other credit facilities. As of October 31, 2008, there was a balance of $150 million outstanding under the Short-Term Facility, with an effective interest rate of 4.00 percent.

7.00% Senior Notes due 2018. In June 2008, PEPL issued $400 million in senior notes due June 15, 2018 with an interest rate of 7.00 percent (*7.00% Senior Notes*). In connection with the issuance of the 7.00% Senior Notes, the Company incurred underwriting costs and debt discount totaling approximately $4.1 million, resulting in approximately $395.9 million in proceeds to the Company.

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Amendment of Credit Facilities. Effective June 20, 2008, the Company entered into the Fifth Amended and Restated Revolving Credit Agreement (*Revolver*) among the Company, as borrower, and the lenders party thereto. The Company entered into the Revolver, which replaces the Fourth Amended and Restated Revolving Credit Agreement, dated as of September 29, 2005, as amended, in order to (i) permit the Company to make additional repurchases of a portion of the depositary shares representing ownership of its 7.55 percent Noncumulative Preferred Stock, Series A (*Preferred Stock*); (ii) permit the Company to redeem all outstanding depositary shares on or after October 8, 2008 in accordance with the terms of its certificate of designations; (iii) create more favorable representations, warranties and covenants for the Company; and (iv) remove certain provisions that are no longer relevant for the Company's needs.

On July 23, 2008, the Company entered into a short-term committed credit facility with one of its existing lenders in the amount of $20 million. The facility will mature on July 22, 2009 and replaces a $15 million uncommitted facility that the Company had in place with that same lender.

On September 30, 2008, the Company entered into a $30 million uncommitted facility with one of its existing lenders. The facility replaced a $15 million uncommitted facility that the Company had in place with that same lender. As of October 3, 2008, the Company was advised by the lender that no borrowings would be allowed under the facility until further notice, due to disruptions in the credit markets. Because this is an uncommitted facility and the Company has not included it as a funding source in its cash flow forecast planning, the lack of availability of the facility does not materially impact the Company's liquidity position.

Remarketing Obligation. On February 8, 2008, the Company remarketed the 4.375% Senior Notes, which yielded no cash proceeds for the Company. The interest rate on the Senior Notes was reset to 6.089 percent per annum effective on and after February 19, 2008. The 6.089% Senior Notes will mature on February 16, 2010. On February 19, 2008, the Company issued 3,693,240 shares of common stock for $100 million in cash proceeds in conjunction with the remarketing of its 4.375% Senior Notes.

Retirement of Debt Obligations

In August 2008, the Company repaid and retired its $300 million 4.80% Senior Notes and $125 million 6.15% Senior Notes using the remaining proceeds from the 7.00% Senior Notes issued in June 2008 and draw downs of its credit facilities.

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8. Employee Benefits

Components of Net Periodic Benefit Cost. Net periodic benefit cost for the periods ended September 30, 2008 and 2007 includes the components noted in the table below.

	Pension Benefits		Other Postretirement Benefits	
	2008	2007	2008	2007
	(In thousands)			
Three Months ended September 30,				
Service cost	$ 686	$ 664	$ 689	$ 489
Interest cost	2,470	2,287	1,405	1,047
Expected return on plan assets	(2,877)	(2,382)	(832)	(719)
Prior service cost (credit) amortization	138	127	(212)	(732)
Recognized actuarial (gain) loss	1,717	1,994	(307)	(204)
Sub-total	2,134	2,690	743	(119)
Regulatory adjustment	705	(515)	666	666
Net periodic benefit cost	$ 2,839	$ 2,175	$ 1,409	$ 547
Nine Months ended September 30,				
Service cost	$ 2,058	$ 1,992	$ 1,942	$ 1,467
Interest cost	7,410	6,861	4,090	3,141
Expected return on plan assets	(8,631)	(7,146)	(2,471)	(2,157)
Prior service cost (credit) amortization	414	381	(888)	(2,196)
Recognized actuarial (gain) loss	5,150	5,982	(919)	(612)
Sub-total	6,401	8,070	1,754	(357)
Regulatory adjustment	2,114	(2,981)	1,998	1,998
Net periodic benefit cost	$ 8,515	$ 5,089	$ 3,752	$ 1,641

In March 2008, a postretirement benefit plan change was approved for Panhandle for retirements beginning April 1, 2008. The change resulted in a pre-tax obligation increase of approximately $9.8 million.

In the Distribution segment, the Company recovers certain qualified pension benefit plan and other postretirement benefit plan costs through rates charged to utility customers. Certain utility commissions require that the recovery of these costs be based on the Employee Retirement Income Security Act of 1974, as amended, or other utility commission specific guidelines. The difference between these amounts and periodic benefit cost calculated pursuant to FASB Statement No. 87, *Employers' Accounting for Pensions and FASB Statement 106, Employers' Accounting for Postretirement Benefits Other Than Pensions,* is deferred as a regulatory asset or liability and amortized to expense over periods promulgated by the applicable utility commission in which this difference will be recovered in rates.

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9. Taxes on Income

The Company's income taxes were as follows:

	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
	(In thousands)			
Income tax expense	$ 19,665	$ 23,853	$ 75,260	$ 68,747
Effective tax rate	30%	35%	30%	28%

The decrease in the EITR for the three-month period ended September 30, 2008 was primarily due to the impact of state income tax rate changes resulting in higher state income tax expense of $4.9 million recorded in the third quarter of 2007, partially offset by a decrease in the tax benefit associated with the dividends received deduction as a result of lower estimated dividends from the Company's unconsolidated investment in Citrus. For the three-month periods ended September 30, 2008 and 2007, the tax benefit of the dividends received deduction was $6 million and $8.1 million, respectively.

The increase in the EITR for the nine-month period ended September 30, 2008 was primarily due to the decrease in the tax benefit associated with the dividends received deduction as a result of lower estimated dividends from the Company's unconsolidated investment in Citrus. For the nine-month periods ended September 30, 2008 and 2007, the tax benefit of the dividends received deduction was $19.8 million and $28.2 million, respectively. The dividends received deduction benefit in 2007 was partially offset by higher state income tax expense of $2.7 million recorded in 2007 attributable to an increase in state income tax rates.

The Company evaluates its tax reserves (unrecognized tax benefits) under the recognition, measurement and derecognition thresholds as prescribed by FIN 48, "*Accounting for Uncertainty in Income Taxes*". The Company increased the amount of its unrecognized tax benefits for certain state filing positions taken in prior periods by nil and $5.1 million ($3.3 million, net of federal tax) during the three- and nine-month periods ended September 30, 2008, respectively.

The Company increased the amount of its unrecognized tax benefits for certain state filing positions taken during the current periods by $1 million ($600,000, net of federal tax) and $3.2 million ($2.1 million, net of federal tax) during the three- and nine-month periods ended September 30, 2008, respectively. The Company decreased the amount of its unrecognized tax benefits as a result of the lapse of the federal statute of limitations for the annual tax periods ended June 30, 2004 and December 31, 2004 by $200,000 and $600,000 during the three- and nine-month periods ended September 30, 2008, respectively.

The Company currently has $8.3 million ($5.4 million, net of federal tax) of unrecognized tax benefits as of September 30, 2008, all of which would impact the Company's EITR if recognized. The Company believes it is reasonably possible that its unrecognized tax benefits may be reduced by $800,000 ($500,000, net of federal tax) within the next twelve months due to settlement of certain state filing positions and lapse of statutes of limitations.

The Company is no longer subject to U.S. federal, state or local examinations for the tax year ended June 30, 2004 and prior years except for state and local jurisdictions under examination. The Company has recorded unrecognized tax benefits of $800,000 ($500,000, net of federal tax) for state and local jurisdictions' assessments for examinations for June 30, 2004 and prior years. The Company also is no longer subject to federal examination for the tax period ended December 31, 2004.

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10. Commitments and Contingencies

Environmental

The Company's operations are subject to federal, state and local laws and regulations regarding water quality, hazardous and solid waste management, air quality control and other environmental matters. These laws and regulations require the Company to conduct its operations in a specified manner and to obtain and comply with a wide variety of environmental registrations, licenses, permits, inspections and other approvals. Failure to comply with environmental requirements may expose the Company to significant fines, penalties and/or interruptions in operations. The Company's environmental policies and procedures are designed to achieve compliance with such laws and regulations. These evolving laws and regulations and claims for damages to property, employees, other persons and the environment resulting from current or past operations may result in significant expenditures and liabilities in the future. The Company engages in a process of updating and revising its procedures for the ongoing evaluation of its operations to identify potential environmental exposures and enhance compliance with regulatory requirements. The Company follows the provisions of American Institute of Certified Public Accountants Statement of Position 96-1, *Environmental Remediation Liabilities,* for recognition, measurement, display and disclosure of environmental remediation liabilities.

The Company is allowed to recover environmental remediation expenditures through rates in certain jurisdictions within its Distribution segment. Although significant charges to earnings could be required prior to rate recovery for jurisdictions that do not have rate recovery mechanisms, management does not believe that environmental expenditures will have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows. The table below reflects the amount of accrued liabilities recorded in the unaudited interim Condensed Consolidated Balance Sheet at September 30, 2008 and December 31, 2007 to cover probable environmental response actions:

	September 30, 2008	December 31, 2007
	(In thousands)	
Current	$ 5,405	$ 6,772
Noncurrent	14,660	15,209
Total Environmental Liabilities	$ 20,065	$ 21,981

SPCC Rules. In May 2007, the EPA extended the SPCC rule compliance dates until July 1, 2009, permitting owners and operators of facilities to prepare or amend and implement SPCC Plans in accordance with previously enacted modifications to the regulations. In October 2007, the EPA proposed amendments to the SPCC rules with the stated intention of providing greater clarity, tailoring requirements, and streamlining requirements. The Company is currently reviewing the impact of the modified regulations on operations in its Transportation and Storage and Gathering and Processing segments and may incur costs for tank integrity testing, alarms and other associated corrective actions as well as potential upgrades to containment structures. Costs associated with such activities cannot be estimated with certainty at this time, but the Company believes such costs will not have a material adverse effect on its consolidated financial position, results of operations or cash flows.

Transportation and Storage Segment Environmental Matters.

Gas Transmission Systems. Panhandle is responsible for environmental remediation at certain sites on its gas transmission systems for contamination resulting from the past use of lubricants containing PCBs in compressed air systems; the past use of paints containing PCBs; and the prior use of wastewater collection facilities and other on-site disposal areas. Panhandle has developed and is implementing a program to remediate such contamination. Remediation and decontamination has been completed at each of the 35 compressor station sites where auxiliary buildings that house the air compressor equipment were impacted by the past use of lubricants containing PCBs. At some locations, PCBs have been identified in paint that was applied many years ago. A program has been implemented to remove and dispose of PCB impacted paint during painting activities. At one location on the Trunkline system, PCBs were discovered on the painted surfaces of equipment in a

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building that is outside the scope of the compressed air system program and the existing PCB impacted paint program. The estimated cost to remediate the painted surfaces at this location is approximately $300,000. Preliminary assessments were completed at all compressor station locations as of September 30, 2008. Subsequent focused assessments indicated PCBs at regulated levels in a small number of samples at 18 locations. Until the complete results of the assessment program are available and the analysis is completed, the costs associated with remediation of the painted surfaces cannot be reasonably estimated.

Other remediation typically involves the management of contaminated soils and may involve remediation of groundwater. Activities vary with site conditions and locations, the extent and nature of the contamination, remedial requirements, complexity and sharing of responsibility. The ultimate liability and total costs associated with these sites will depend upon many factors. If remediation activities involve statutory joint and several liability provisions, strict liability, or cost recovery or contribution actions, Panhandle could potentially be held responsible for contamination caused by other parties. In some instances, such as the Pierce waste oil sites described below, Panhandle may share liability associated with contamination with other PRPs. Panhandle may also benefit from contractual indemnities that cover some or all of the cleanup costs. These sites are generally managed in the normal course of business or operations. The Company believes the outcome of these matters will not have a material adverse effect on its consolidated financial position, results of operations or cash flows.

PEPL and Trunkline, together with other non-affiliated parties, were identified as potentially liable for conditions at three former waste oil disposal sites in Illinois – the Pierce Oil Springfield site, the Dunavan Waste Oil site and the McCook site (collectively, the *Pierce Waste Oil sites*). PEPL and Trunkline received notices of potential liability from the U.S. EPA for the Dunavan site by letters dated September 30, 2005. Although no formal notice has been received for the Pierce Oil Springfield site, special notice letters are anticipated and the process of listing the site on the National Priority List has begun. No formal notice has been received for the McCook site. The Company believes the outcome of these matters will not have a material adverse effect on its consolidated financial position, results of operations or cash flows.

On June 16, 2005, PEPL experienced a release of liquid hydrocarbons near Pleasant Hill, Illinois. The EPA took the lead role in overseeing the subsequent cleanup activities, which have been completed. PEPL has resolved claims of affected boat owners and the marina operator. PEPL received a violation notice from the IEPA alleging that PEPL was in apparent violation of several sections of the Illinois Environmental Protection Act by allowing the release. The violation notice did not propose a penalty. Responses to the violation notice were submitted and the responses were discussed with the agency. In December 2005, the IEPA notified PEPL that the matter might be considered for referral to the Office of the Attorney General, the State's Attorney or the EPA for formal enforcement action and the imposition of penalties. The only contact from the IEPA on this matter has been three requests for information to which the Company responded in January 2007, April 2008 and August 2008. The Company believes the outcome of this matter will not have a material adverse effect on its consolidated financial position, results of operations or cash flows.

Air Quality Control. In early April 2007, the IEPA proposed a rule to the IPCB for adoption to control NOx emissions from reciprocating engines and turbines, including a provision applying the rule beyond issues addressed by federal provisions, pursuant to a blanket statewide application. After objections were filed with the IPCB, the IEPA filed an amended proposal withdrawing the statewide applicability provisions of the proposed rule and applying the rule requirements to non-attainment areas. The amended proposal was approved on January 10, 2008. No controls on PEPL and Trunkline stations are required under the most recent proposal. However, the IEPA indicated in earlier industry discussions that it was reserving the right to make future proposals for statewide controls. In the event the IEPA proposes a statewide rule again, preliminary estimates indicate the cost of compliance would require minimum capital expenditures of approximately $45 million for emission controls.

The KDHE has established certain contingency measures as part of the agency's ozone maintenance plan for the Kansas City area. These measures will be triggered if there are any new elevated ozone readings in the Kansas City area. One of the NOx emission sources that will be impacted is the PEPL Louisburg compressor station. In addition, the U.S. EPA has revised the ozone standard and the Kansas City area will likely be designated as a non-attainment area under the new and stricter standard. A meeting was held with KDHE on August 14, 2008 to discuss issues associated with reducing emissions at the Louisburg compressor station. In the event KDHE requires emission reductions, it is estimated that approximately $14 million in capital expenditures will be required.

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Gathering and Processing Segment Environmental Matters.

Gathering and Processing Systems. SUGS is responsible for environmental remediation at certain sites on its gathering and processing systems, resulting primarily from releases of hydrocarbons. SUGS has a program to remediate such contamination. The remediation typically involves the management of contaminated soils and may involve remediation of groundwater. Activities vary with site conditions and locations, the extent and nature of the contamination, remedial requirements and complexity. The ultimate liability and total costs associated with these sites will depend upon many factors. These sites are generally managed in the normal course of business or operations. The Company believes the outcome of these matters will not have a material adverse effect on its consolidated financial position, results of operations or cash flows.

Air Quality Control. On June 16, 2006, SUGS, as the facility operator and holder of a 50 percent interest in a partnership that leases the Grey Ranch facility, submitted information to the TCEQ in connection with a request to permit the Grey Ranch facility to continue its current level of emissions. The State of Texas required all previously grandfathered emission sources to obtain permits or shut down by March 1, 2008. By letter dated September 5, 2007, the TCEQ issued a permit extending current emission levels to March 1, 2009. Prior to the conclusion of the extension period, SUGS must obtain appropriate permits and implement an emission control strategy that achieves specific maximum allowable emissions rates. It is anticipated that the Company will not bear any of the costs associated with the emission controls. It is expected that Roc Gas Company, or one of its affiliates, which holds the other 50 percent interest in the partnership that leases the Grey Ranch facility (and also owns the site and facility), will bear all the costs necessary to construct control devices and modify its nearby compression facilities in order to meet maximum allowable emission limits.

Distribution Segment Environmental Matters.

The Company is responsible for environmental remediation at various contaminated sites that are primarily associated with former *MGPs* and sites associated with the operation and disposal activities of former MGPs that produced a fuel known as "town gas". Some byproducts of the historic manufactured gas process may be regulated substances under various federal and state environmental laws. To the extent these byproducts are present in soil or groundwater at concentrations in excess of applicable standards, investigation and remediation may be required. The sites include properties that are part of the Company's ongoing operations, sites formerly owned or used by the Company and sites owned by third parties. Remediation typically involves the management of contaminated soils and may involve removal of old MGP structures and remediation of groundwater. Activities vary with site conditions and locations, the extent and nature of the contamination, remedial requirements, complexity and sharing of responsibility; some contamination may be unrelated to former MGPs. The ultimate liability and total costs associated with these sites will depend upon many factors. If remediation activities involve statutory joint and several liability provisions, strict liability, or cost recovery or contribution actions, the Company could potentially be held responsible for contamination caused by other parties. In some instances, the Company may share liability associated with contamination with other PRPs, and may also benefit from insurance policies or contractual indemnities that cover some or all of the cleanup costs. These sites are generally managed in the normal course of business or operations. The Company believes the outcome of these matters will not have a material adverse effect on its consolidated financial position, results of operations or cash flows.

North Attleborough MGP Site in Massachusetts. In November 2003, the MDEP issued a Notice of Responsibility to New England Gas Company, acknowledging receipt of prior notifications and investigative reports submitted by New England Gas Company, following the discovery of suspected coal tar material at the site. Subsequent sampling in the adjacent river channel revealed sediment impacts necessitating the investigation of off-site properties. The Company, working with the MDEP, is in the process of performing assessment work at these properties. In a September 2006 report filed with the MDEP, the Company proposed a remedy for the upland portion of the site by means of an engineered barrier. Construction of this remedy was completed in October 2008. Assessment activities continue both on- and off-site to define the nature and extent of the impacts. It is estimated that the Company will spend approximately $7.5 million over the next several years to complete the investigation and remediation activities at this site, as well as maintain the engineered barrier. As New England Gas Company is allowed to recover environmental remediation expenditures through rates associated with its Massachusetts operations, the estimated costs associated with this site have been included in *Regulatory assets* in the Condensed Consolidated Balance Sheet.

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Litigation

The Company is involved in legal, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies regarding matters arising in the ordinary course of business, some of which involve substantial amounts. Where appropriate, the Company has made accruals in accordance with FASB Statement No. 5, *Accounting for Contingencies*, in order to provide for such matters. The Company believes the final disposition of these proceedings will not have a material adverse effect on its consolidated financial position, results of operations or cash flows.

Bay Street, Tiverton, Rhode Island Site. On March 17, 2003, the RIDEM sent the Company's New England Gas Company division a letter of responsibility pertaining to soils allegedly impacted by historic MGP residuals in a residential neighborhood in Tiverton, Rhode Island. Without admitting responsibility or accepting liability, New England Gas Company began assessment work in June 2003 and has continued to perform assessment field work since that time. On September 19, 2006, RIDEM filed an Amended Notice of Violation seeking an administrative penalty of $1,000/day, which as of the date of RIDEM's filing totaled $258,000 and continues to accrue. In June 2007, the Rhode Island Legislature considered, but failed to adopt, legislation that would have increased the maximum administrative penalty under a Notice of Violation to $50,000/day on a prospective basis. Similar legislation was considered in June 2008 that would have increased the maximum administrative penalty under a Notice of Violation to $25,000/day on a prospective basis. That proposed legislation was not adopted. On April 19, 2007, the Company filed a complaint, and an accompanying preliminary injunction motion, against RIDEM in Rhode Island Superior Court, seeking, among other things, a declaratory judgment that RIDEM's Amended Notice of Violation is premised on an unlawful application of RIDEM's regulations and that RIDEM's pending administrative proceeding against the Company is invalid. On July 13, 2007, the Superior Court dismissed the Company's suit, finding that RIDEM's AAD has original jurisdiction to determine "responsible party" status and finding premature the Company's challenge to RIDEM's unlawful application of its own regulations because the Company did not first seek a ruling on that issue from RIDEM's AAD. The Company has appealed from part of the Superior Court's ruling, and has also filed a motion for summary judgment in the AAD proceeding seeking dismissal thereof based on RIDEM's unlawful application of its own regulations. Briefing on the summary judgment motion is now complete. The Hearing Officer in the AAD proceeding has not yet issued a ruling on that motion. In consideration of the ongoing settlement discussions described below, the RIDEM administrative proceeding has been stayed. The Company will continue to vigorously defend itself in the AAD proceeding.

During 2005, four lawsuits were filed against New England Gas Company in Rhode Island regarding the Tiverton neighborhood. These lawsuits were consolidated for trial. The plaintiffs seek to recover damages for the diminution in value of their property, lost use and enjoyment of their property and emotional distress in an unspecified amount. The Company removed the lawsuits to federal court and filed motions to dismiss. On November 3, 2006, the Court dismissed plaintiffs' claims relating to gross negligence, private nuisance, infliction of emotional distress and violation of the Rhode Island Hazardous Waste Management Act. The Court denied the Company's motion to dismiss as to claims relating to negligence, strict liability and public nuisance, as well as plaintiffs' request for punitive damages. In September and October 2007, the court granted the Company's motion to serve third-party complaints on a total of nine PRPs. Among the PRPs the Company impleaded is the Town of Tiverton, which asserted a counterclaim against the Company under the Comprehensive Environmental Response, Compensation, and Liability Act. On January 30, 2008, the Court denied the Company's motion for partial judgment on the pleadings seeking dismissal of plaintiffs' claims for remediation, finding, contrary to the Company's contention, that RIDEM does not have exclusive jurisdiction to determine the responsibility for and extent of remediation of plaintiffs' properties. On February 13, 2008, the Court entered a "Trial Order" superseding several prior orders, and directing that (1) on or about April 24, 2008, the Court will conduct a "Phase I" trial on claims asserted by plaintiffs and by Tiverton against the Company; (2) the Phase I trial will be bifurcated into a liability stage, and, if necessary, a damages stage, with both stages to be tried before the same jury; (3) the discovery cutoff date for the Phase I trial is extended from February 29 to March 21, 2008; (4) if necessary, a

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"Phase II" trial shall address the Company's third-party claims against the PRPs it has impleaded; and (5) the parties to the Phase II trial shall have 120 days after the Phase I trial to conduct discovery related thereto. The Court subsequently ruled that Tiverton's claims against the Company will be tried in the Phase II trial. The Company filed a motion seeking extension of the discovery and trial date, which was denied in material part. The Phase I trial, which was scheduled to commence on April 28, 2008, was adjourned without date by the Court in consideration of the progress of settlement discussions between the Company and the plaintiffs. The Court held a conference on November 5, 2008 regarding the status of settlement discussions. No settlement has been reached. A new Phase I trial date has not been set. The Company believes the outcome of these matters will not have a material adverse effect on its consolidated financial position, results of operations or cash flows.

Mercury Release. In October 2004, New England Gas Company discovered that one of its facilities had been broken into and that mercury had been released both inside a building and in the immediate vicinity, including a parking lot in a neighborhood several blocks away. Mercury from the parking lot was apparently tracked into nearby apartment units, as well as other buildings. Cleanup was completed at the property and nearby apartment units. The vandals who broke into the facility were arrested and convicted. On October 16, 2007, the U.S. Attorney in Rhode Island filed a three-count indictment against the Company in the U.S. District Court for the District of Rhode Island alleging violation of permitting requirements under the federal RCRA and notification requirements under the federal Emergency Planning and Community Right to Know Act (*EPCRA*) relating to the 2004 incident. The Company entered a not guilty plea on October 29, 2007 and trial commenced on September 22, 2008. On October 15, 2008, the jury acquitted Southern Union on the EPCRA count and one of the two RCRA counts, and found the Company guilty on the other RCRA count. The Company intends to file post-verdict motions not later than December 1, 2008. In the event such motions are not granted, sentencing as regards the single RCRA count, is scheduled for February 20, 2009. The Company believes the outcome of this matter will not have a material adverse effect on its consolidated financial position, results of operations or cash flows.

On January 20, 2006, a complaint was filed against the Company in the Superior Court in Providence, Rhode Island regarding the mercury release from the Pawtucket facility, asserting claims for personal injury and property damage as a result of the release. The suit was removed to Rhode Island federal court on January 27, 2006. A motion to remand the case to state court filed by plaintiffs was denied on April 16, 2007. The Company thereafter moved to dismiss plaintiffs' amended complaint, which motion was granted in part, dismissing claims for public nuisance, private nuisance and violation of Rhode Island's Hazardous Waste Management Act, leaving plaintiffs with claims for negligence and strict liability. The Court has set December 1, 2008 as the Closure Date for all discovery. On October 18, 2007, an attorney representing other Pawtucket residents filed suit against the Company in the Superior Court in Providence asserting claims similar to those pending in the above-described federal court suit for personal injury and property damage. An additional complaint alleging personal injury arising out of the mercury release was filed on behalf of three plaintiffs with the District Court for the Sixth District, Providence County, Rhode Island, on January 22, 2008. The Company will vigorously defend all such suits. The Company believes the outcome of this matter will not have a material adverse effect on its consolidated financial position, results of operations or cash flows.

Jack Grynberg. Jack Grynberg, an individual, filed actions for damages against a number of companies, including Panhandle, now transferred to the U.S. District Court for the District of Wyoming, alleging mis-measurement of gas volumes and Btu content, resulting in lower royalties to mineral interest owners. Among the defendants are Panhandle, Citrus, Florida Gas and certain of their affiliates (*Company Defendants*). On October 20, 2006, the District Judge adopted in part the earlier recommendation of the Special Master in the case and ordered the dismissal of the case against the Company Defendants. Grynberg is appealing that action to the Tenth Circuit Court of Appeals. Grynberg's opening brief was filed on July 31, 2007. Respondents filed their brief rebutting Grynberg's arguments on November 21, 2007. A hearing before the Court of Appeals was held on September 25, 2008. The Court has not yet ruled on Grynberg's appeal. A similar action, known as the Will Price litigation, also has been filed against a number of companies, including Panhandle, in U.S. District Court for the District of Kansas. Panhandle is currently awaiting the decision of the trial judge on the defendants' motion to dismiss the Will Price action. Panhandle and the other Company Defendants believe that their measurement practices conformed to the terms of their FERC gas tariffs, which were filed with and approved by FERC. As a result, the Company believes that it has meritorious defenses to these lawsuits (including FERC-related affirmative defenses, such as the filed rate/tariff doctrine, the primary/exclusive jurisdiction of FERC, and the defense that Panhandle and the other Company Defendants complied with the terms of their tariffs) and will continue to vigorously defend against them, including any appeal from the dismissal of the Grynberg case. The Company does not believe the outcome of these cases will have a material adverse effect on its consolidated financial position, results of operations or cash flows.

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GP II Energy Litigation. On October 23, 2006, landowners filed suit against the Company in the 109th District Court of Winkler County, Texas, seeking money damages, equitable relief and punitive damages alleging continuing pollution to underground aquifers underlying the plaintiffs' approximately 16,000 acre property. SUGS operated the Halley Plant, a hydrocarbon processing facility, which is located on a limited portion of the plaintiff landowners' ranch pursuant to a lease. On February 15, 2008, the Company learned that plaintiffs significantly revised their claims to include approximately $40 million in economic damages and approximately $85 million in punitive damages. On March 31, 2008, plaintiffs filed a third amended petition revising their claims to include approximately $96 million in economic damages and approximately $193 million in punitive damages. The parties finalized a settlement of the case in October 2008, pursuant to which SUGS paid $1.4 million to the plaintiffs and all claims were dismissed with prejudice.

Other Commitments and Contingencies.

2008 Hurricane Damage. In September 2008, Hurricanes Gustav and Ike came ashore on the Louisiana and Texas coasts. Damage from the hurricanes have affected both the Company's Transportation and Storage and Gathering and Processing segments. Offshore transportation facilities, including Sea Robin and Trunkline's Terrebonne system, suffered damage to several platforms and are continuing to experience reduced volumes. The SUGS business was indirectly adversely affected by Hurricane Ike.

With respect to the Company's preliminary damage assessments associated with Hurricane Gustav, the Company estimates an expense impact to its facilities totaling approximately $3 million, which was recorded in the third quarter of 2008. The capital expenditure impact related to the hurricane was insignificant. As these amounts are below the Company's $10 million property insurance deductible, the Company does not expect any of the repair and replacement costs associated with Hurricane Gustav to be reimbursed by its property insurance carrier.

With respect to the Company's preliminary damage assessments associated with Hurricane Ike, the Company estimates an expense impact related to its facilities totaling approximately $7 million, which was recorded in the third quarter of 2008. The Company also preliminarily estimates that capital expenditures relating to the hurricane will total approximately $90 million in 2008 and 2009. The estimates are subject to further revision as the assessment of the damage to the Company's facilities is ongoing. The Company anticipates reimbursement from its property insurance carrier for a significant portion of the damages in excess of its $10 million deductible; however, the recoverable amount is subject to pro rata reduction to the extent that the level of total accepted claims from all insureds exceeds the carrier's $750 million aggregate exposure limit. The Company's insurance provider has announced that it expects to reach the $750 million limit, but the amount of any applicable pro rata reduction cannot be determined until the Company's insurance provider has completed its assessment of all submitted claims.

With respect to the Company's Gathering and Processing segment, SUGS' facilities were not affected by the hurricanes. SUGS' third-party NGL fractionator sustained damage to its Mont Belvieu, Texas facility as a result of Hurricane Ike. SUGS was forced to shut in its natural gas processing plants and attendant production on September 11, 2008 for approximately a week, and operated at reduced production levels for the remainder of the month. The majority of SUGS' September 2008 NGL production was fractionated and sold, with approximately 3.1 million gallons of NGL delivered into Mont Belvieu storage pending completion of repairs resulting from the hurricane and a previously scheduled maintenance outage at the fractionation facility for approximately four weeks during the fourth quarter of 2008. The stored NGL totaling $2.5 million as of September 30, 2008 is included in *Inventories* in the Condensed Consolidated Balance Sheet.

2005 Hurricane Damage. Late in the third quarter of 2005, Hurricanes Katrina and Rita came ashore along the Upper Gulf Coast. These hurricanes caused damage to property and equipment owned by Sea Robin, Trunkline, and Trunkline LNG. The Company has filed approximately $32 million of damage claims related to the hurricanes, primarily amounts for repairs, replacement or abandonment of damaged property and equipment at Sea Robin and Trunkline. The Company has received reimbursement from its property insurance carrier for a significant portion of the damages in excess of the $5 million deductible in effect in 2005. Such reimbursement is currently estimated by the Company's property insurance carrier to be limited to 63 percent of the portion of the claimed damages accepted by the insurance carrier, based on a pro rata reduction to the extent accepted claims exceeded the carrier's $1 billion aggregate exposure limit. As of September 30, 2008, the Company has received payments of $13 million from its insurance carrier, representing a 55 percent payout to date of the 63 percent payout ultimately expected. No additional receivables due from the insurance carrier have been recorded related to the hurricane claims as of September 30, 2008.

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11. Reportable Segments

The Company's reportable business segments are organized based on the way internal managerial reporting presents the results of the Company's various businesses to its executive management for use in determining the performance of the businesses and in allocating resources to the businesses, as well as based on similarities in economic characteristics, products and services, types of customers, methods of distribution and regulatory environment. The Company operates in three reportable segments: Transportation and Storage, Gathering and Processing, and Distribution.

The Transportation and Storage segment operations are conducted through Panhandle and the Company's investment in Citrus. Through Panhandle, the Company is primarily engaged in the interstate transportation and storage of natural gas from the Gulf of Mexico, South Texas and the Panhandle regions of Texas and Oklahoma to major U.S. markets in the Midwest and Great Lakes regions. Panhandle also provides LNG terminalling and regasification services. Through its investment in Citrus, the Company has an interest in and operates Florida Gas. Florida Gas is primarily engaged in the interstate transportation of natural gas from South Texas through the Gulf Coast region to Florida.

The Gathering and Processing segment is primarily engaged in connecting wells of natural gas producers to its gathering system, treating natural gas to remove impurities to meet pipeline quality specifications, processing natural gas for the removal of NGL, and redelivering natural gas and NGL to a variety of markets. Its operations are conducted through SUGS in Texas and New Mexico.

The Distribution segment is primarily engaged in the local distribution of natural gas in Missouri and Massachusetts.

Revenue included in the Corporate and other category is primarily attributable to PEI Power Corporation, which generates and sells electricity. PEI Power Corporation does not meet the quantitative threshold for segment reporting.

The Company evaluates operational and financial segment performance based on several factors, of which the primary financial measure is EBIT, which is a non-GAAP measure. The Company defines EBIT as *Net earnings available for common stockholders*, adjusted for the following:

- items that do not impact net earnings, such as extraordinary items, discontinued operations and the impact of changes in accounting principles;
- income taxes;
- interest;
- dividends on preferred stock; and
- loss on extinguishment of preferred stock.

EBIT may not be comparable to measures used by other companies and should be considered in conjunction with net earnings and other performance measures such as operating income or net cash flows provided by operating activities.

Sales of products or services between segments are billed at regulated rates or at market rates, as applicable. There were no material intersegment revenues during the three- and nine-month periods ended September 30, 2008 and 2007.

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The following table sets forth certain selected financial information for the Company's segments for the periods presented.

Segment Data	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
	(In thousands)			
Revenues from external customers:				
Transportation and Storage	$ 173,400	$ 158,963	$ 528,784	$ 489,699
Gathering and Processing	392,328	285,182	1,248,313	887,111
Distribution	89,892	80,093	561,449	513,864
Total segment operating revenues	655,620	524,238	2,338,546	1,890,674
Corporate and other	1,663	1,235	4,490	3,080
Total consolidated revenues from external customers	$ 657,283	$ 525,473	$ 2,343,036	$ 1,893,754
Depreciation and amortization expense:				
Transportation and Storage	$ 26,133	$ 21,863	$ 76,885	$ 63,634
Gathering and Processing	15,721	14,713	46,537	43,849
Distribution	7,615	7,633	22,909	22,646
Total segment depreciation and amortization	49,469	44,209	146,331	130,129
Corporate and other	580	691	1,662	1,901
Total depreciation and amortization expense	$ 50,049	$ 44,900	$ 147,993	$ 132,030
Segment performance:				
Transportation and Storage EBIT	$ 89,128	$ 90,129	$ 292,822	$ 300,906
Gathering and Processing EBIT	26,951	20,020	67,641	41,506
Distribution EBIT	3,613	9,173	36,733	49,162
Total segment EBIT	119,692	119,322	397,196	391,574
Corporate and other	(19)	517	5,194	6,186
Interest expense	53,232	50,703	154,536	154,034
Federal and state income tax expense	19,665	23,853	75,260	68,747
Net earnings	46,776	45,283	172,594	174,979
Preferred stock dividends	2,264	4,342	10,041	13,024
Loss on extinguishment of preferred stock	2,036	-	4,031	-
Net earnings available for common stockholders	$ 42,476	$ 40,941	$ 158,522	$ 161,955
Expenditures for long-lived assets:				
Transportation and Storage	$ 75,023	$ 181,771	$ 347,852	$ 379,070
Gathering and Processing	19,365	9,560	52,144	33,377
Distribution	12,152	11,501	28,860	30,240
Total segment expenditures for long-lived assets	106,540	202,832	428,856	442,687
Corporate and other	5,479	841	7,235	2,394
Total consolidated expenditures for long-lived assets (1)	$ 112,019	$ 203,673	$ 436,091	$ 445,081

(1) Includes net capital accruals totaling $(16.4) million and $26.9 million for the three-month periods ended September 30, 2008 and 2007, respectively and $(32.7) million and $63 million for the nine-month periods ended September 30, 2008 and 2007, respectively.

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Segment Data	**September 30, 2008**	**December 31, 2007**
	(In thousands)	
Total assets:		
Transportation and Storage	$ 4,891,700	$ 4,550,822
Gathering and Processing	1,676,087	1,709,901
Distribution	1,094,558	1,020,460
Total segment assets	7,662,345	7,281,183
Corporate and other	99,293	116,730
Total consolidated assets	$ 7,761,638	$ 7,397,913

12. Fair Value Measurement

Adoption of Statement No. 157.

Effective January 1, 2008, the Company partially adopted Statement No. 157, which provides a framework for measuring fair value (see *Note 2 – New Accounting Principles*). As defined in Statement No. 157, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The Company utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about credit risk (both the Company's own credit risk and counterparty credit risk) and the risks inherent in the inputs to any applicable valuation techniques. These inputs can be readily observable, market corroborated, or generally unobservable. The Company endeavors to utilize the best available information, including valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. Statement No. 157 establishes a three-tier fair value hierarchy, which prioritizes the inputs used to measure fair value as follows:

- Level 1 – Observable inputs such as quoted prices in active markets for identical assets or liabilities;

- Level 2 – Observable inputs such as: (i) quoted prices for similar assets or liabilities in active markets; (ii) quoted prices for identical or similar assets or liabilities in markets that are not active; or (iii) valuations based on pricing models where significant inputs (e.g., interest rates, yield curves, etc.) are observable for the assets or liabilities, are derived principally from observable market data, or can be corroborated by observable market data, for substantially the full term of the assets or liabilities; and

- Level 3 – Unobservable inputs, including valuations based on pricing models, discounted cash flow methodologies or similar techniques where at least one significant model assumption or input is unobservable. Unobservable inputs are used to the extent that observable inputs are not available and reflect the Company's own assumptions about the assumptions market participants would use in pricing the assets or liabilities. Unobservable inputs are based on the best information available in the circumstances, which might include the Company's own data.

Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of these assets and liabilities and their placement within the fair value hierarchy.

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The following table sets forth the Company's financial assets and liabilities that are measured at fair value on a recurring basis at September 30, 2008.

	Fair Value as of September 30, 2008	Fair Value Measurements at September 30, 2008 Using Fair Value Hierarchy		
		Level 1	Level 2	Level 3
		(In thousands)		
Assets:				
Cash equivalents (money market investments)	$ 820	$ 820	$ -	$ -
Commodity derivatives	22,114	-	(609)	22,723
Long-term investments	919	919	-	-
Total	$ 23,853	$ 1,739	$ (609)	$ 22,723
Liabilities:				
Commodity derivatives	$ (54,591)	$ -	$ (54,591)	$ -
Interest-rate derivatives	(18,325)	-	-	(18,325)
Total	$ (72,916)	$ -	$ (54,591)	$ (18,325)

The Company's Level 3 instruments include commodity derivative instruments, such as natural gas and NGL processing spread swaps, and interest-rate swap derivatives that are valued using an income approach where at least one significant assumption or input to the underlying pricing model, discounted cash flow methodology or similar technique is unobservable – i.e. natural gas swap valuations include basis adjustments to NYMEX forward curves obtained from third-party pricing services; fractionation processing spread swap valuations include natural gas liquid forward curves derived from historical correlations of pricing data; and interest rate swap valuations include composite yield curves provided by the bank counterparty. The financial assets and liabilities that the Company has categorized in Level 3 may later be reclassified to Level 2 when the Company is able to obtain additional observable market data to corroborate the unobservable inputs to models used to measure the fair value of these assets and liabilities. The Company's Level 2 instruments include natural gas swap derivatives that are valued based on pricing models where significant inputs are observable. The Company's Level 1 instruments consist of money market mutual funds and trading securities related to a non-qualified deferred compensation plan that are valued based on active market quotes.

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The following tables present a reconciliation of the change in the Company's financial assets and liabilities measured at fair value on a recurring basis using significant unobservable inputs (Level 3) for the periods indicated.

	Level 3 Financial Assets and Liabilities		
	Assets	Liabilities	
	Commodity Derivatives	Commodity Derivatives	Interest-rate Derivatives
		(In thousands)	
Three Months Ended September 30, 2008			
Beginning balance	$ 655	$ 50,305	$ 15,664
Reclassification between assets and liabilities	(50,305)	(50,305)	-
Total gains or losses (realized and unrealized):			
Included in operating revenues (1)	4,327	-	-
Included in other comprehensive income	58,981	-	5,194
Purchases and settlements, net	9,065	-	(2,533)
Ending balance	$ 22,723	$ -	$ 18,325
Nine Months Ended September 30, 2008			
Beginning balance	$ 1,320	$ (5,404)	$ 17,121
Reclassification between assets and liabilities	5,404	5,404	-
Total gains or losses (realized and unrealized):			
Included in operating revenues (1)	(23,875)	-	-
Included in other comprehensive income	19,440	-	6,229
Purchases and settlements, net	20,434	-	(5,025)
Ending balance	$ 22,723	$ -	$ 18,325

(1) The amount included in operating revenues for the three months ended September 30, 2008 that is attributable to the change in unrealized gains or losses relating to commodity derivative assets and commodity derivative liabilities held at September 30, 2008 was a $14.7 million gain and nil, respectively. The amount included in operating revenues for the nine months ended September 30, 2008 that is attributable to the change in unrealized gains or losses relating to commodity derivative assets and commodity derivative liabilities held at September 30, 2008 was a $4.8 million loss and nil, respectively.

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Gathering and Processing Segment Derivative Financial Instruments. The following table summarizes SUGS' principal commodity derivative instruments as of September 30, 2008 (all instruments are settled monthly), which were developed based upon operating conditions and expected equity NGL sales volumes.

Instrument Type	Index	Average Price (per MMBtu)	Volumes (MMBtu/d) 2008	Volumes (MMBtu/d) 2009	Fair Value Asset (Liability)
					(In thousands)
***Natural Gas - Cash Flow Hedges* (1)**					
Swap	IF - Waha	$ 8.01	5,525	-	$ 1,155
Swap	IF - El Paso Permian	8.01	4,475	-	935
Swap	Gas Daily - Waha	8.42	11,050	-	2,726
Swap	Gas Daily - Waha	9.49	-	11,050	8,932
Swap	Gas Daily - El Paso Permian	8.42	8,950	-	2,208
Swap	Gas Daily - El Paso Permian	9.49	-	8,950	7,235
		Total Swaps	30,000	20,000	$ 23,191
***Processing Spread - Economic Hedges* (2)**					
Put	IF - Waha	$ 8.15	6,119	-	$ 475
Put	IF - El Paso Permian	8.15	4,956	-	385
		Total Puts	11,075	-	$ 860
Swap	Gas Daily - Waha	$ 6.85	15,981	-	$ (2,836)
Swap	Gas Daily - Waha	7.40	-	16,575	1,406
Swap	Gas Daily - El Paso Permian	6.85	12,944	-	(2,297)
Swap	Gas Daily - El Paso Permian	7.40	-	13,425	1,139
		Total Swaps	28,925	30,000	$ (2,588)

(1) The Company's natural gas swap arrangements have been designated as cash flow hedges. The effective portion of changes in the fair value of the cash flow hedges is recorded in *Accumulated other comprehensive loss* until the related hedged items impact earnings. Any ineffective portion of a cash flow hedge is reported in current-period earnings.
(2) The Company's processing spread put and swap arrangements are treated as economic hedges, with the change in fair value reported in current-period earnings.

There were no up-front costs associated with the derivative instruments entered into in 2008.

13. Regulation and Rates

The Company commenced construction of an enhancement at its Trunkline LNG terminal in February 2007. This infrastructure enhancement project, which was originally expected to cost approximately $250 million, plus capitalized interest, will increase send out flexibility at the terminal and lower fuel costs. Recent cost projections indicate the construction costs will likely be approximately $400 million, plus capitalized interest. The revised costs, which are under review, reflect increases in the quantities and cost of materials required, higher contract labor costs, including reduced productivity due to an August 2008 tropical storm and the two September 2008 hurricanes, and an allowance for additional contingency funds, if needed. The negotiated rate with the project's customer, BG LNG Services, will be adjusted based on final capital costs pursuant to a contract-based formula. The project is currently expected to be in operation around the end of the second quarter of 2009. In addition, Trunkline LNG and BG LNG Services have agreed to extend the existing terminal and pipeline services agreements to coincide with the infrastructure enhancement project contract, which runs 20 years from the in-service date. Approximately $311.9 million and $178.3 million of costs are included in the line item *Construction work-in-*

progress at September 30, 2008 and December 31, 2007, respectively.

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Sea Robin filed a rate case with FERC in June 2007, requesting an increase in its maximum rates. Several parties submitted protests to the rate increase filing with FERC. On July 30, 2007, FERC suspended the effectiveness of the filed rate increase until January 1, 2008. The filed rates were put into effect on January 1, 2008, subject to refund. On February 14, 2008, at the request of the participants in the proceeding, the procedural schedule was suspended to facilitate the filing of a settlement. On April 29, 2008, Sea Robin submitted to FERC a Stipulation and Agreement (*Settlement*) that would resolve all issues in the proceeding. The Administrative Law Judge certified the Settlement to FERC on June 3, 2008. The Settlement is currently pending further FERC action. Customer refund liability provisions of approximately $3.4 million, including interest, have been recorded as of September 30, 2008.

On July 17, 2008, New England Gas Company made a filing with the MDPU seeking to implement an annual base rate increase of approximately $5.6 million. It is expected that new rates resulting from this filing will not take effect until February 1, 2009.

On September 15, 2008, New England Gas Company made a filing with the MDPU seeking recovery of approximately $4 million, or 50 percent of the amount by which its 2007 earnings fell below a return on equity of 7 percent. This filing was made pursuant to New England Gas Company's rate settlement approved by the MDPU in 2007. The procedural schedule is expected to conclude by the end of the first quarter of 2009 and, if approved, the rate change would be implemented on or before November 1, 2009.

On July 1, 2008, the Circuit Court of Greene County, Missouri made a docket entry indicating that, following judicial review, it had affirmed the Report and Order issued by the MPSC resolving Missouri Gas Energy's general rate increase that went into effect on April 3, 2007. While that judicial review proceeding, which had been initiated by both Missouri Gas Energy (challenging the adequacy of the overall rate increase awarded) and the Office of the Public Counsel (challenging the design of residential distribution rates that eliminates the impact of weather and conservation for residential margin revenues and related earnings), has been appealed to the Southern District of the Missouri Court of Appeals by both Missouri Gas Energy and the Office of the Public Counsel, the Company does not believe the outcome of the judicial review will have a material adverse effect on its consolidated financial position, results of operations or cash flows.

14. Stockholders' Equity

Dividends. The table below presents the amount of cash dividends declared and paid in the respective periods:

Shareholder Record Date	Date Paid	Amount Per Share	Amount Paid (In thousands)
September 26, 2008	October 10, 2008	$ 0.15	$ 18,597
June 27, 2008	July 11, 2008	0.15	18,595
March 28, 2008	April 11, 2008	0.15	18,592

Preferred Stock. On May 22, 2008, the Company announced that the Finance Committee of its Board of Directors had authorized a program to repurchase a portion of the depositary shares representing ownership of its Preferred Stock. Repurchases are made at the Company's discretion in the open market and through privately negotiated transactions, subject to market conditions, applicable legal requirements and other factors. The Company has the right to redeem all of the Preferred Stock at any time at par after October 8, 2008. During the three-month period ended September 30, 2008, the Company paid $62.3 million to repurchase 2,482,250 depository shares representing 248,225 shares of Preferred Stock, resulting in a $2 million loss adjustment charged to *Retained earnings* which reduced *Net earnings available for common stockholders*. During the nine-month period ended September 30, 2008, the Company paid $110.9 million to repurchase 4,401,087 depository shares representing 440,109 shares of Preferred Stock, resulting in a $4 million loss adjustment charged to *Retained earnings* which reduced *Net earnings available for common stockholders*. In October 2008, the Company paid $4.3 million to repurchase an additional 198,900 depositary shares representing 19,890 shares of Preferred Stock, which will result in a $500,000 gain adjustment to *Retained earnings* increasing *Net earnings available for common stockholders*.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

INTRODUCTION

This Management's Discussion and Analysis of Financial Condition and Results of Operations is provided as a supplement to the accompanying unaudited interim condensed consolidated financial statements and notes to help provide an understanding of Southern Union's financial condition, changes in financial condition and results of operations. The following section includes an overview of the Company's business as well as recent developments that management of the Company believes are important in understanding its results of operations, and to anticipate future trends in those operations. Subsequent sections include an analysis of the Company's results of operations on a consolidated basis and on a segment basis for each reportable segment, and information relating to the Company's liquidity and capital resources, quantitative and qualitative disclosures about market risk and other matters.

OVERVIEW

The Company's business purpose is to provide gathering, processing, transportation, storage and distribution of natural gas and NGL in a safe, efficient and dependable manner. The Company's reportable business segments are determined based on the way internal managerial reporting presents the results of the Company's various businesses to its executive management for use in determining the performance of the businesses and in allocating resources to the businesses as well as based on similarities in economic characteristics, products and services, types of customers, methods of distribution and regulatory environment. The Company operates in three reportable segments: Transportation and Storage, Gathering and Processing, and Distribution.

RESULTS OF OPERATIONS

Overview

The Company evaluates operational and financial segment performance using several factors, of which the primary financial measure is EBIT, which is a non-GAAP measure. The Company defines EBIT as *Net earnings available for common stockholders*, adjusted for the following:

- items that do not impact net earnings, such as extraordinary items, discontinued operations and the impact of changes in accounting principles;
- income taxes;
- interest;
- dividends on preferred stock; and
- loss on extinguishment of preferred stock.

EBIT may not be comparable to measures used by other companies and should be considered in conjunction with net earnings and other performance measures such as operating income or net cash flows provided by operating activities.

The following table provides a reconciliation of EBIT (by segment) to *Net earnings available for common stockholders*.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	**2007**	**2008**	**2007**
	(In thousands)			
EBIT:				
Transportation and storage segment	$ 89,128	$ 90,129	$ 292,822	$ 300,906
Gathering and processing segment	26,951	20,020	67,641	41,506
Distribution segment	3,613	9,173	36,733	49,162
Corporate and other	(19)	517	5,194	6,186
Total EBIT	119,673	119,839	402,390	397,760
Interest	53,232	50,703	154,536	154,034
Earnings before income taxes	66,441	69,136	247,854	243,726
Federal and state income tax expense	19,665	23,853	75,260	68,747
Net earnings	46,776	45,283	172,594	174,979
Preferred stock dividends	2,264	4,342	10,041	13,024
Loss on extinguishment of preferred stock	2,036	-	4,031	-
Net earnings available for common stockholders	$ 42,476	$ 40,941	$ 158,522	$ 161,955

Three-month period ended September 30, 2008 versus the three-month period ended September 30, 2007. The Company's $1.5 million increase in *Net earnings available for common stockholders* in the three-month period ended September 30, 2008 versus the same period in 2007 was primarily due to:

- Higher EBIT contributions of $6.9 million from the Gathering and Processing segment primarily due to higher market-driven realized average natural gas and NGL prices in 2008 and the impact of $1.5 million of net hedging gains in 2008 versus 2007, partially offset by reduced natural gas and NGL sales in September 2008 when the Company was forced to shut in its natural gas processing plants and attendant production because of damage by Hurricane Ike to the Company's third-party NGL fractionator, the establishment of a $2.7 million bad debt reserve for receivables associated with a company that filed for bankruptcy protection and a $1.4 million charge related to settlement of the GP II Energy litigation;
- Lower income tax expense of $4.2 million primarily due to the EITR of 30 percent in the 2008 period versus 35 percent in the 2007 period primarily due to the impact of state income tax rate changes resulting in higher state income tax rates in the 2007 period, partially offset by a decrease in the tax benefit associated with the dividends received deduction as a result of lower estimated dividends from the Company's unconsolidated investment in Citrus;
- Lower EBIT contributions of $5.6 million from the Distribution segment primarily due to $2.7 million of higher operating expenses primarily attributable to higher injuries and damage litigation claims and higher provisions for uncollectible customer accounts and lower net revenues of $1.8 million primarily due to lower market-driven pipeline capacity release and off-system sales in the 2008 period versus the 2007 period;
- Higher interest expense of $2.5 million primarily due to higher outstanding long-term debt balances in the 2008 period versus the 2007 period, partially offset by lower interest expense resulting from the effect of lower LIBOR-based interest rates on the Company's variable interest rate debt and lower outstanding balances associated with the Company's credit facilities in the 2008 period versus the 2007 period; and
- Lower EBIT contributions of $1 million from the Transportation and Storage segment primarily due to a $2.1 million decrease in equity earnings from the Company's unconsolidated investment in Citrus primarily due to its higher operating expenses, partially offset by a higher EBIT contribution of $1.1 million from Panhandle primarily attributable to higher transportation reservation revenues, partially offset by higher operating expenses.

Nine-month period ended September 30, 2008 versus the nine-month period ended September 30, 2007. The Company's $3.4 million decrease in *Net earnings available for common stockholders* in the nine-month period ended September 30, 2008 versus the same period in 2007 was primarily due to:

- Lower EBIT contributions of $12.4 million from the Distribution segment primarily due to higher operating expenses of $9.9 million primarily attributable to higher environmental remediation and benefit costs and higher provisions for uncollectible customer accounts and lower net revenues of $2 million primarily due to lower market-driven pipeline capacity release and off-system sales in the 2008 period versus the 2007 period;
- Lower EBIT contributions of $8.1 million from the Transportation and Storage segment primarily due to lower equity earnings of $20.8 million primarily resulting from $18.7 million of nonrecurring gains in the 2007 period resulting from the sale of bankruptcy-related receivables and from the settlement of litigation, partially offset by higher EBIT contributions of $12.7 million in 2008 from Panhandle primarily attributable to higher transportation reservation revenues, partially offset by higher operating expenses;
- Higher income tax expense of $6.5 million primarily due to the EITR of 30 percent in the 2008 period versus 28 percent in the 2007 period resulting from the decrease in the tax benefit associated with the reduction in the dividends received deduction as a result of lower estimated dividends from the Company's unconsolidated investment in Citrus, partially offset by higher state income tax expense in 2007 attributable to an increase in state income tax rates; and
- Higher EBIT contributions of $26.1 million from the Gathering and Processing segment primarily due to higher market-driven realized average natural gas and NGL prices in 2008 and lower fuel, flare and unaccounted for natural gas volumes in the 2008 period versus the 2007 period, partially offset by the impact of $24.5 million of higher net hedging losses in the 2008 period versus the 2007 period, reduced natural gas and NGL sales in September 2008 when the Company was forced to shut in its natural gas processing plants and attendant production because of damage by Hurricane Ike to the Company's third-party NGL fractionator, the establishment of a $2.7 million bad debt reserve for receivables associated with a company that filed for bankruptcy protection and a $1.4 million charge related to settlement of the GP II Energy litigation.

Business Segment Results

Transportation and Storage Segment. The Transportation and Storage segment is primarily engaged in the interstate transportation and storage of natural gas in the Midwest and from the Gulf Coast to Florida, and LNG terminalling and regasification services. The Transportation and Storage segment's operations, conducted through Panhandle and Florida Gas, are regulated as to rates and other matters by FERC. Demand for gas transmission on Panhandle's pipeline systems is seasonal, with the highest throughput and a higher portion of annual total operating revenues and EBIT occurring in the traditional winter heating season in the first and fourth calendar quarters. Florida Gas' pipeline system experiences the highest throughput in the summer period due to gas-fired generation loads in the second and third calendar quarters.

Historically, much of the Transportation and Storage segment's business was conducted through long-term contracts with customers. Over the past several years, some customers within the segment have shifted to shorter term transportation services contracts. This shift, which can increase the volatility of revenues, is primarily due to changes in market conditions and competition with other pipelines, new supply sources, changing supply sources and volatility in natural gas prices. Average reservation revenue rates realized by the Transportation and Storage segment are dependent on certain factors, including but not limited to rate regulation, customer demand for reserved capacity, capacity sold levels for a given period and, in some cases, utilization of capacity. Commodity revenues are also dependent upon a number of variable factors including weather, storage levels, and customer demand for firm, interruptible and parking services. The majority of the Transportation and Storage segment revenues are related to firm capacity reservation charges.

The Company's regulated transportation and storage businesses periodically file for changes in their rates, which are subject to approval by FERC. Changes in rates and other tariff provisions resulting from these regulatory proceedings have the potential to impact negatively the Company's results of operations and financial condition.

The following table presents the results of operations applicable to the Company's Transportation and Storage segment for the periods presented:

Transportation and Storage Segment	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
	(In thousands)			
Financial Information:				
Operating revenues	$ 173,400	$ 158,963	$ 528,784	$ 489,699
Operating expenses	72,858	63,987	196,211	184,676
Depreciation and amortization	26,133	21,863	76,885	63,634
Taxes other than on income and revenues	8,226	7,350	24,419	22,438
Total operating income	66,183	65,763	231,269	218,951
Earnings from unconsolidated investments	22,212	24,300	60,026	80,822
Other income, net	733	66	1,527	1,133
EBIT	$ 89,128	$ 90,129	$ 292,822	$ 300,906
Operating information:				
Panhandle natural gas volumes transported (TBtu)	356	341	1,085	1,116
Florida Gas natural gas volumes transported (TBtu) (1)	226	225	610	563

(1) Represents 100 percent of natural gas volumes transported by Florida Gas versus the Company's effective equity ownership interest of 50 percent.

Three-month period ended September 30, 2008 versus the three-month period ended September 30, 2007. The $1 million EBIT reduction in the three-month period ended September 30, 2008 versus the same period in 2007 was primarily due to lower 2008 equity earnings of $2.1 million offset by a higher 2008 EBIT contribution from Panhandle totaling $1.1 million.

Equity earnings, primarily attributable to the Company's unconsolidated investment in Citrus, were lower by $2.1 million in 2008 versus 2007 primarily due to the following items, adjusted where applicable to reflect the Company's proportional equity share:

- Higher operating expenses of $2.5 million primarily due to increased property taxes and higher overall costs experienced in 2008 applicable to employee labor and benefits, outside contract services costs and other operating costs;
- Lower other income of $800,000 primarily due to reduced AFUDC;
- Higher depreciation expense of $600,000 primarily due to increased plant placed in service;
- Higher debt interest cost of $600,000 primarily due to higher average outstanding revolver debt balances;
- Higher operating revenues of $1.4 million primarily due to higher reservation revenues attributable to increased capacity from prior expansions; and
- Lower income taxes of $1.1 million primarily due to lower pre-tax earnings.

Panhandle's $1.1 million EBIT improvement was primarily due to the following items:

- Higher operating revenues of $14.4 million primarily related to the following items:
  - Higher transportation reservation revenues of $14.8 million primarily due to the phased completion of the Trunkline Field Zone Expansion project during the period December 2007 to February 2008 and reduced discounting resulting in higher average rates realized on contracts driven by higher customer demand;
  - Higher storage revenues of $1.9 million due to additional contracted storage capacity;
  - Higher commodity revenues of $300,000 primarily due to a rate increase on Sea Robin, net of related customer liability refund provisions, which includes the impact of approximately $1.4 million of lower revenues attributable to reduced volumes flowing after Hurricane Ike and lower parking revenues of $1.2 million due to market conditions; and
  - A $2.2 million decrease in LNG terminalling revenue due to lower volumes from a reduced number of LNG cargoes during 2008.

  The Company preliminarily estimates lost revenue opportunities of $3 million will be experienced in the fourth quarter of 2008 as a result of Hurricane Ike. Such preliminary estimate is subject to further update based upon the timing of the Company completing the repair and replacement of its damaged property and equipment and the timing of producers completing their interconnects to the Company's offshore system. Currently, the Company anticipates the majority of the interconnects will be completed by the 2008 year end.

- Higher operating expenses of $8.9 million primarily attributable to:
  - Expense of $9.5 million for the estimated impact related to damages to the Company's facilities resulting from Hurricanes Gustav and Ike;
  - A $2.3 million increase in contract storage costs resulting from an increase in leased storage capacity;
  - A $1.1 million decrease in LNG power costs resulting from a reduced number of cargoes during 2008;
  - A $1.7 million decrease in fuel tracker costs primarily due to a net over-recovery in 2008 versus a net under-recovery in 2007; and
  - A $1.6 million decrease in hydrostatic testing costs primarily due to a higher number of tests performed in the 2007 period.

- Increased depreciation and amortization expense of $4.3 million due to a $643.9 million increase in property, plant and equipment placed in service after September 30, 2007. Depreciation and amortization expense is expected to continue to increase primarily due to higher capital spending, primarily from the LNG terminal infrastructure enhancement and compression modernization construction projects; and
- Increased taxes, other than on income and revenues, of $900,000 primarily due to higher property taxes attributable to higher property tax assessments resulting from increased earnings, partially offset by lower compressor fuel tax resulting from decreased LNG cargoes.

Nine-month period ended September 30, 2008 versus the nine-month period ended September 30, 2007. The $8.1 million EBIT reduction in the nine-month period ended September 30, 2008 versus the same period in 2007 was primarily due to lower 2008 equity earnings of $20.8 million offset by a higher 2008 EBIT contribution from Panhandle totaling $12.7 million.

Equity earnings, primarily attributable to the Company's unconsolidated investment in Citrus, were lower by $20.8 million in 2008 versus 2007 primarily due to the following items, adjusted where applicable to reflect the Company's proportional equity share:

- A $15.1 million nonrecurring gain recorded in the 2007 period related to the settlement of litigation;
- A $3.6 million nonrecurring gain recorded in the 2007 period related to the sale of bankruptcy-related receivables;
- Higher operating expenses of $4 million primarily due to increased property taxes and higher overall costs experienced in 2008 applicable to employee labor and benefits, outside contract services costs and other operating costs;
- Higher depreciation expense of $1.7 million primarily due to increased plant placed in service;
- Higher operating revenues of $5.7 million primarily due to higher reservation revenues of $4 million attributable to increased capacity from prior expansions and the extra day in 2008 for the leap year; and
- Lower income taxes of $6.7 million primarily due to lower pre-tax earnings.

Panhandle's $12.7 million EBIT improvement was primarily due to the following items:

- Higher operating revenues of $39.1 million primarily related to the following items:
  - Higher transportation reservation revenues of $37.9 million primarily due to the phased completion of the Trunkline Field Zone Expansion project during the period December 2007 to February 2008 and reduced discounting resulting in higher average rates realized on contracts driven by higher customer demand, and approximately $1.2 million of additional revenues attributable to the extra day in the 2008 leap year;
  - Higher commodity revenues of $7.1 million primarily due to a rate increase on Sea Robin, net of related customer liability refund provisions and the impact of approximately $1.4 million of lower revenues attributable to reduced volumes flowing after Hurricane Ike;
  - Higher storage revenues of $5.5 million due to increased leased storage capacity; and
  - A $10.5 million decrease in LNG terminalling revenue due to lower volumes from decreased LNG cargoes during 2008.

  The Company preliminarily estimates lost revenue opportunities of $3 million will be experienced in the fourth quarter of 2008 as a result of Hurricane Ike. Such preliminary estimate is subject to further update based upon the timing of the Company completing the repair and replacement of its damaged property and equipment and the timing of producers completing their interconnects to the Company's offshore system. Currently, the Company anticipates the majority of the interconnects will be completed by the 2008 year end.

- Higher operating expenses of $11.5 million primarily attributable to:
  - Expense of $9.5 million for the estimated impact related to damages to the Company's facilities resulting from Hurricanes Gustav and Ike;
  - An $8 million increase in contract storage costs resulting from an increase in leased storage capacity;
  - A $3.8 million increase in benefits primarily due to higher active and retiree medical costs experienced in the 2008 period and higher defined contribution savings plan expenses resulting from an increase in Panhandle savings plan benefits in March 2008;
  - A $3.1 million increase in insurance costs primarily due to higher property premiums;
  - A $9.5 million decrease in LNG power costs resulting from a reduced number of LNG cargoes during 2008; and
  - A $6.2 million decrease in fuel tracker costs primarily due to a net over-recovery in 2008 versus a net under-recovery in 2007.

- Increased depreciation and amortization expense of $13.3 million due to a $643.9 million increase in property, plant and equipment placed in service after September 30, 2007. Depreciation and amortization expense is expected to continue to increase primarily due to higher capital spending, primarily from the LNG terminal infrastructure enhancement and compression modernization construction projects and other capital expenditures; and
- Increased taxes, other than on income and revenues, of $2 million primarily due to higher property taxes attributable to higher property tax assessments resulting from increased earnings, partially offset by lower compressor fuel tax on a reduced number of LNG cargoes.

Gathering and Processing Segment. The Gathering and Processing segment is primarily engaged in connecting wells of natural gas producers to its gathering system, treating natural gas to remove impurities to meet pipeline quality specifications, processing natural gas for the removal of NGL, and redelivering natural gas and NGL to a variety of markets.

The following table presents the results of operations applicable to the Company's Gathering and Processing segment:

Gathering and Processing Segment	**Three Months Ended September 30, 2008**	**Three Months Ended September 30, 2007**	**Nine Months Ended September 30, 2008**	**Nine Months Ended September 30, 2007**
	(In thousands)			
Operating revenues, excluding impact of commodity derivative instruments	$ 390,825	$ 285,229	$ 1,275,044	$ 889,323
Commodity derivative amount realized	(12,236)	166	(21,344)	(603)
Commodity derivative amount unrealized	13,739	(213)	(5,387)	(1,609)
Operating revenues	392,328	285,182	1,248,313	887,111
Cost of gas and other energy	(320,281)	(230,295)	(1,058,820)	(743,260)
Gross margin (1)	72,047	54,887	189,493	143,851
Operating expenses	27,488	20,240	70,626	58,763
Depreciation and amortization	15,721	14,713	46,537	43,849
Taxes other than on income and revenues	976	720	3,495	2,199
Total operating income	27,862	19,214	68,835	39,040
Earnings from unconsolidated investments	(914)	263	(1,180)	947
Other expense, net	3	543	(14)	1,519
EBIT	$ 26,951	$ 20,020	$ 67,641	$ 41,506
Operating information:				
Volumes				
Avg natural gas processed (MMBtu/d)	386,977	422,094	409,460	427,710
Avg NGL produced (gallons/d)	1,225,386	1,305,044	1,329,725	1,330,635
Avg natural gas wellhead (MMBtu/d)	535,153	664,960	593,972	634,075
Natural gas sales (MMBtu)	22,646,553	25,677,262	70,471,942	81,468,279
NGL sales (gallons) (2)	123,993,890	116,757,571	424,253,218	348,656,686
Average Pricing				
Realized natural gas ($/MMBtu) (3)	$ 8.15	$ 5.72	$ 8.60	$ 6.30
Realized NGL ($/gallon) (3)	1.64	1.16	1.55	1.03
Natural Gas Daily Waha ($/MMBtu)	7.68	5.72	8.59	6.39
Natural Gas Daily El Paso ($/MMBtu)	7.53	5.62	8.45	6.27
Estimated plant processing spread ($/gallon)	0.89	0.62	0.76	0.45

(1) Gross margin consists of *Operating revenues* less *Cost of gas and other energy*. The Company believes that this measurement is more meaningful for understanding and analyzing the Gathering and Processing segment's operating results for the periods presented because commodity costs are a significant factor in the determination of the segment's revenues.
(2) In addition to volumes processed by SUGS, includes volumes sold under various buy-sell arrangements.
(3) Excludes impact of realized and unrealized commodity derivative gains and losses detailed in the above EBIT presentation.

Three-month period ended September 30, 2008 versus the three-month period ended September 30, 2007. The $6.9 million EBIT improvement in the three-month period ended September 30, 2008 versus the same period in 2007 was primarily due to the following items:

- Higher gross margin of $17.2 million primarily as the result of:
  - Higher market-driven realized average natural gas and NGL prices (unadjusted for the impact of realized and unrealized commodity derivative gains and losses) of $8.15 per MMBtu and $1.64 per gallon in the 2008 period versus $5.72 per MMBtu and $1.16 per gallon in the 2007 period, respectively;
  - Impact of $1.5 million of net hedging gains in the 2008 period versus the 2007 period; and
  - Unfavorable gross margin impact of approximately $10.6 million resulting from damage by Hurricane Ike to the Company's third-party NGL fractionator. Commencing September 11, 2008, the Company was forced to shut in its natural gas processing plants and attendant production for approximately a week and operated at reduced production levels for the remainder of the month.

    The Company's third party NGL fractionator will be unavailable to provide fractionation services for approximately four weeks during the fourth quarter of 2008 due to a scheduled maintenance outage. In order to continue operating at normal production levels during the fourth quarter of 2008, the Company has arranged for a portion of its NGL to be fractionated by a different third-party fractionator during the scheduled maintenance outage. The portion of NGL which are not fractionated by either fractionator will be delivered into Mont Belvieu storage. The Company expects a significant portion of the stored NGL to be fractionated and sold before year end.

- Operating expenses were higher by $7.2 million primarily due to:
  - A $2.7 million bad debt reserve for receivables associated with a company that filed for bankruptcy protection in the third quarter of 2008;
  - A $1.4 million provision in the third quarter of 2008 related to the settlement of the GP II Energy litigation;
  - An $800,000 increase in chemical and lubricants costs, which generally track with the price of oil and are expected to remain higher in the 2008 period versus the 2007 period; and
  - A $500,000 increase in utilities costs primarily due to higher compressor fuel costs and the associated rising cost of natural gas in 2008 versus 2007;
- Higher depreciation expense of $1 million primarily attributable to a $71 million increase in property, plant and equipment placed in service after September 30, 2007; and
- Lower equity earnings of $1.2 million from the Company's unconsolidated investment in Grey Ranch, which has been out of service since June 2008 because of a fire at the Grey Ranch processing plant. The Grey Ranch processing plant was placed back in service in late October 2008.

Nine-month period ended September 30, 2008 versus the nine-month period ended September 30, 2007. The $26.1 million EBIT improvement in the nine-month period ended September 30, 2008 versus the same period in 2007 was primarily due to the following items:

- Higher gross margin of $45.6 million primarily as the result of:
  - Higher market-driven realized average natural gas and NGL prices (unadjusted for the impact of realized and unrealized commodity derivative gains and losses) of $8.60 per MMBtu and $1.55 per gallon in the 2008 period versus $6.30 per MMBtu and $1.03 per gallon in the 2007 period, respectively;
  - Favorable gross margin impact of lower levels of fuel, flare, and unaccounted for gas losses in the 2008 period versus the unusually high levels experienced in the first and second quarters in the 2007 period;
  - Impact of $24.5 million of higher net hedging losses in the 2008 period versus the 2007 period; and
  - Unfavorable gross margin impact of approximately $10.6 million resulting from damage by Hurricane Ike to the Company's third-party NGL fractionator. Commencing September 11, 2008, the Company was forced to shut in its natural gas processing plants and attendant production for approximately a week and operated at reduced production levels for the remainder of the month.

The Company's third party NGL fractionator will be unavailable to provide fractionation services for approximately four weeks during the fourth quarter of 2008 due to a scheduled maintenance outage. In order to continue operating at normal production levels during the fourth quarter of 2008, the Company has arranged for a portion of its NGL to be fractionated by a different third-party fractionator during the scheduled maintenance outage. The portion of NGL which are not fractionated by either fractionator will be delivered into Mont Belvieu storage. The Company expects a significant portion of the stored NGL to be fractionated and sold before year end.

- Operating expenses were higher by $11.9 million primarily due to:
  - A $2.7 million bad debt reserve for receivables associated with a company that filed for bankruptcy protection in the third quarter of 2008;
  - A $1.4 million provision in the third quarter of 2008 related to the settlement of the GP II Energy litigation;
  - A $2.5 million increase in utilities costs primarily due to higher compressor fuel costs and the associated rising cost of natural gas in 2008 versus 2007; and
  - A $2.3 million increase in chemical and lubricants costs, which generally track with the price of oil and are expected to remain higher in the 2008 period versus the 2007 period;
- Higher depreciation expense of $2.7 million primarily attributable to a $71 million increase in property, plant and equipment placed in service after September 30, 2007; and
- Lower equity earnings of $2.1 million from the Company's unconsolidated investment in Grey Ranch, which has been out of service since June 2008 because of a fire at the Grey Ranch processing plant. The Grey Ranch processing plant was placed back in service in late October 2008.

Distribution Segment. The Distribution segment is primarily engaged in the local distribution of natural gas in Missouri and Massachusetts through its Missouri Gas Energy and New England Gas Company divisions, respectively. The Distribution segment's operations are regulated as to rates and other matters by the regulatory commissions of the states in which each operates. The Distribution segment's operations have historically been sensitive to weather and seasonal in nature, with a significant percentage of annual operating revenues and EBIT occurring in the traditional winter heating season in the first and fourth calendar quarters. However, the MPSC approved distribution rates effective April 3, 2007 for Missouri Gas Energy's residential customers (which comprise approximately 87 percent of its total natural gas sales customers and approximately 74 percent of its gross natural gas sales revenues) that eliminate the impact of weather and conservation for residential margin revenues and related earnings in Missouri.

The following table presents the results of operations applicable to the Company's Distribution segment for the periods presented:

Distribution Segment	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
	(In thousands)			
Financial Information:				
Net operating revenues (1)	$ 43,825	$ 45,657	$ 160,585	$ 162,542
Operating expenses	29,410	26,693	91,531	81,649
Depreciation and amortization	7,615	7,633	22,909	22,646
Taxes other than on income and revenues	2,747	1,822	8,391	7,945
Total operating income	4,053	9,509	37,754	50,302
Other income (expenses), net	(440)	(336)	(1,021)	(1,140)
EBIT	$ 3,613	$ 9,173	$ 36,733	$ 49,162
Operating Information:				
Gas sales volumes (MMcf)	3,612	3,584	46,945	41,691
Gas transported volumes (MMcf)	5,131	5,182	20,817	19,462
Weather – Degree Days: (2)				
Missouri Gas Energy service territories	54	27	3,474	2,907
New England Gas Company service territories	74	35	3,505	3,575

(1) Operating revenues for the Distribution segment are reported net of *Cost of gas and other energy* and *Revenue-related taxes*, which are pass-through costs.

(2) "Degree days" are a measure of the coldness of the weather experienced. A degree day is equivalent to each degree that the daily mean temperature for a day falls below 65 degrees Fahrenheit.

Three-month period ended September 30, 2008 versus the three-month period ended September 30, 2007. The $5.6 million EBIT reduction in the three-month period ended September 30, 2008 versus the same period in 2007 was primarily due to the following items:

- Lower net operating revenues of $1.8 million primarily due to $1.6 million of lower market-driven pipeline capacity release and off-system sales in the 2008 period versus the 2007 period.
- Higher operating expenses of $2.7 million primarily attributable to:
  - Higher injuries and damage claims of $1.4 million related to ongoing litigation;
  - Higher provisions for uncollectible customer accounts of approximately $1 million primarily resulting from the impact of the current depressed economic conditions on some of the Company's customers. The Company expects that more governmental assistance will be offered to its low income customers, potentially reducing the amount required in its related customer allowance reserve; and
  - Higher benefit expenses of $600,000 primarily due to increased pension amortization expense resulting from the Missouri Gas Energy rate case that became effective during the second quarter of 2007.

Nine-month period ended September 30, 2008 versus the nine-month period ended September 30, 2007. The $12.4 million EBIT reduction in the nine-month period ended September 30, 2008 versus the same period in 2007 was primarily due to the following items:

- Lower net operating revenues of $2 million primarily due to $2.5 million of lower market-driven pipeline capacity release and off-system sales in the 2008 period versus the 2007 period.
- Higher operating expenses of $9.9 million primarily attributable to:
  - Higher environmental remediation costs of $2.8 million primarily attributable to site investigation evaluations completed during 2008. Missouri Gas Energy has requested from the MPSC authority to defer environmental costs in excess of recoveries from insurance carriers or other parties for consideration in a future rate proceeding and expects a ruling on its deferral authority request before the end of 2008;
  - Higher benefit expenses of $2.7 million primarily due to increased pension amortization expense resulting from the Missouri Gas Energy rate case that became effective during the second quarter of 2007; and
  - Higher provisions for uncollectible customer accounts of approximately $2.1 million primarily resulting from the impact of the current depressed economic conditions on some of the Company's customers. The Company expects that more governmental assistance will be offered to its low income customers, potentially reducing the amount required in its related customer allowance reserve.

Corporate and Other

Nine-month period ended September 30, 2008 versus the nine-month period ended September 30, 2007. The EBIT reduction of $1 million was primarily due to the following items:

- A $4.2 million increase in legal fees associated with ongoing litigation;
- Favorable impact of $1.5 million of higher insurance reimbursements associated with environmental claims settlements with the insurance providers in the 2008 period versus the 2007 period; and
- Higher EBIT contribution of $1.9 million from PEI Power Corporation primarily due to higher revenues resulting from increased electricity production and higher electricity prices in the 2008 period versus the 2007 period.

Interest Expense

Three-month period ended September 30, 2008 versus the three-month period ended September 30, 2007. Interest expense was $2.5 million higher in the three-month period ended September 30, 2008 versus the same period in 2007 primarily due to:

- Higher interest expense of $8.8 million primarily due to higher outstanding debt balances from the $300 million 6.20% Senior Notes and the $400 million 7.00% Senior Notes issued in October 2007 and June 2008, respectively, partially offset by lower interest expense from the repayment of the $300 million 4.80% Senior Notes and the $125 million 6.15% Senior Notes due August 2008;
- Higher net interest expense of $400,000 associated with the remarketing of the $100 million 4.375% Senior Notes in February 2008, which were replaced with the higher interest rate $100 million 6.089% Senior Notes;
- Lower interest expense of $3.8 million primarily due to the effect of lower LIBOR interest rates on the $465 million term loan agreement that was amended in June 2007 to extend the maturity date to June 2012 at a lower interest rate;
- Lower interest expense of $1.7 million primarily due to the impact of the higher level of interest costs capitalized attributable to higher average capital project balances outstanding in 2008 compared to 2007; and
- Lower interest expense of $1.7 million associated with borrowings under the Company's credit agreements primarily due to lower interest rates in 2008 compared to 2007.

Nine-month period ended September 30, 2008 versus the Nine-month period ended September 30, 2007. Interest expense was $500,000 higher in the nine-month period ended September 30, 2008 versus the same period in 2007 primarily due to:

- Higher interest expense of $19.4 million primarily due to higher outstanding debt balances from the $300 million 6.20% Senior Notes issued in October 2007, the $400 million 7.00% Senior Notes issued June 2008, and the $455 million 2012 Term Loan entered into in March 2007, partially offset by lower interest expense from the repayment of the $300 million 4.80% Senior Notes due August 2008, the $200 million 2.75% Senior Notes in March 2007, and the Trunkline LNG Holdings, LLC (LNG Holdings) $255.6 million Term Loan in March 2007;
- Higher net interest expense of $1 million associated with the remarketing of the $100 million 4.375% Senior Notes in February 2008, which were replaced with the higher interest rate $100 million 6.089% Senior Notes;
- Lower interest expense of $10.3 million primarily due to the effect of lower LIBOR interest rates on the $465 million term loan agreement that was amended in June 2007 to extend the maturity date to June 2012 at a lower interest rate;
- Lower interest expense of $6 million primarily due to the impact of the higher level of interest costs capitalized attributable to higher average capital project balances outstanding in 2008 compared to 2007; and
- Lower interest expense of $3.9 million associated with borrowings under the Company's credit agreements primarily due to lower interest rates in 2008 compared to 2007.

Federal and State Income Taxes

The Company's income taxes were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
	(In thousands)			
Income tax expense	$ 19,665	$ 23,853	$ 75,260	$ 68,747
Effective tax rate	30%	35%	30%	28%

Three-month period ended September 30, 2008 versus the three-month period ended September 30, 2007. The decrease in the EITR was primarily due to the impact of state income tax rate changes resulting in higher state income tax expense of $4.9 million recorded in the third quarter 2007, partially offset by a decrease in the tax benefit associated with the dividends received deduction as a result of lower estimated dividends from the Company's unconsolidated investment in Citrus. For the three-month periods ended September 30, 2008 and 2007, the tax benefit of the dividends received deduction was $6 million and $8.1 million, respectively.

Nine-month period ended September 30, 2008 versus the nine-month period ended September 30, 2007. The increase in the EITR was primarily due to the decrease in the tax benefit associated with the dividends received deduction as a result of lower estimated dividends from the Company's unconsolidated investment in Citrus. For the nine-month periods ended September 30, 2008 and 2007, the tax benefit of the dividends received deduction was $19.8 million and $28.2 million, respectively. The dividends received deduction benefit in 2007 was partially offset by higher state income tax expense of $2.7 million recorded in 2007 attributable to an increase in state income tax rates.

LIQUIDITY AND CAPITAL RESOURCES

The Liquidity and Capital Resources information contained herein should be read in conjunction with the related information set forth in *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources* of the Company's Form 10-K for the year ended December 31, 2007.

Cash generated from internal operations constitutes the Company's primary source of liquidity. The Company's working capital deficit at September 30, 2008 is $348.7 million. This includes $60.9 million of debt maturing in July 2009, which is expected to be funded using cash generated from internal operations and/or from draw downs of its credit facilities. Additional sources of liquidity include use of available credit facilities and may include various equity offerings, project and bank financings and proceeds from asset dispositions. The availability and terms relating to such liquidity will depend upon various factors and conditions such as the Company's combined cash flow and earnings, the Company's resulting capital structure and conditions in the financial markets at the time of such offerings. Acquisitions, which generally require a substantial increase in expenditures, and related financings also affect the Company's combined results. Future acquisitions or related financings or refinancing may involve the issuance of shares of the Company's common stock, which could have a dilutive effect on the then-current stockholders of the Company.

Financial Sector Exposure

Recent events in the global financial markets have caused the Company to place increased scrutiny on its liquidity position and the financial condition of its critical third-party business partners. The purpose of this heightened review, which was based on publicly available information, was to assess the potential impact of the credit crisis and related liquidity issues on its business partners and to assess the associated business risks to the Company. The review focused on the Company's revolving credit facilities, future capital needs (including long-term borrowing needs and potential refinancing plans) of the Company and its joint ventures, derivative counterparties and customer and other contractual relationships.

The Company notes that while there is no way to predict the extent or duration of any negative impact that the current credit disruptions in the economy will have on its liquidity position, there is no current expectation that the impact on the Company would be significant. However, the Company does believe credit spreads will remain elevated throughout 2009, compared to recent years. As such, the Company is considering refinancing obligations that mature in 2009 prior to their maturity dates and timing of any required capital market transactions to take advantage of favorable issuance windows that may become evident in the markets.

Sources (Uses) of Cash

	Nine months ended September 30, 2008	2007	Change
		(In thousands)	
Cash flows provided by (used in):			
Operating activities	$ 373,442	$ 388,720	$ (15,278)
Investing activities	(465,540)	(418,252)	(47,288)
Financing activities	89,468	43,520	45,948
Increase (decrease) in cash and cash equivalents	$ (2,630)	$ 13,988	$ (16,618)

Operating activities. Cash provided by operating activities decreased by $15.3 million in the 2008 period versus the same period in 2007. Cash flows provided by operating activities before changes in operating assets and liabilities for the 2008 period were $410.9 million compared with $386.7 million for the 2007 period. Changes in operating assets and liabilities used cash of $37.5 million in 2008 and provided cash of $2 million in 2007, resulting in a decrease in cash of $39.5 million in 2008 compared to 2007. The $39.5 million decrease in cash is primarily due to an $89 million increase in Distribution segment inventories due to increased volumes for use in the winter months and higher market-driven gas prices, partially offset by decreased accounts receivables in the Gathering and Processing segment of $66.9 million resulting from lower period-end market-driven index pricing and decreased production available for sale due to Hurricane Ike.

Investing activities. The Company's business strategy includes making prudent capital expenditures primarily across its base of interstate transmission, storage, gathering, processing and distribution assets and growing the businesses through the selective acquisition of assets in order to position itself favorably in the evolving natural gas markets.

The $47.3 million increase in invested cash is primarily due to the $78.6 million of increased capital spending in the Transportation and Storage segment, partially offset by the $49.3 million in working capital adjustment payments made in the 2007 period related to the 2006 sales of certain distribution assets.

The following table presents a summary of additions to property, plant and equipment by segment, including additions related to major projects for the periods presented.

Property, Plant and Equipment Additions	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
	(In thousands)	
Transportation and Storage Segment		
LNG Terminal Expansions/Enhancements	$ 122,474	$ 84,570
Trunkline Field Zone Expansion	69,729	134,203
East End Enhancement	35,503	35,861
Compression Modernization	51,578	48,609
Other, primarily pipeline integrity, system reliability, information technology, air emission compliance	68,568	75,827
Total	347,852	379,070
Gathering and Processing Segment	52,144	33,377
Distribution Segment		
Missouri Safety Program	9,873	7,544
Other, primarily system replacement and expansion	18,987	22,696
Total	28,860	30,240
Corporate and other	7,235	2,394
Total (1)	$ 436,091	$ 445,081

(1) Includes net capital accruals totaling $(32.7) million and $63 million for the nine-month periods ended September 30, 2008 and 2007, respectively.

Principal Capital Expenditure Projects. The Company's capital expenditure programs through 2008 are expected to be funded primarily by cash flows from operations and from financings more fully described in *Part I, Item 1. Financial Statements (Unaudited), Note 7 – Debt Obligations*. During the first quarter of 2008, the Company completed construction of its Trunkline system Field Zone Expansion project for a total estimated cost of approximately $255 million, plus capitalized interest. The Company's Trunkline LNG terminal infrastructure enhancement project, with a current estimated construction cost of approximately $400 million, plus capitalized interest, is still expected to be placed into operation in the second quarter of 2009. See *Part I, Item 1. Financial Statements (Unaudited), Note 10 – Commitments and Contingencies – Other Commitments and Contingencies* for a discussion related to the Company's capital expenditure obligations resulting from damages incurred from hurricanes in the third quarter of 2008 and 2005.

Potential Sea Robin Impairment. Sea Robin, comprised primarily of offshore facilities, suffered damage related to several platforms from Hurricane Ike. The Company has estimated capital expenditures of $45 million to replace damaged property and equipment of Sea Robin. This estimate is subject to further revision as the damage assessment is ongoing. The Company anticipates reimbursement from its property insurance carrier for its damages in excess of its $10 million deductible, except for certain expenditures not reimbursable under the insurance policy terms. See *Part I, Item 1. Financial Statements (Unaudited), Note 10 – Commitments and Contingencies – 2008 Hurricane Damage* for additional related information. To the extent the Company's capital expenditures are not recovered through insurance proceeds, its net investment in Sea Robin's property and equipment would increase without necessarily generating additional revenues unless the incremental costs are recovered through future rate proceedings. If the amount of Sea Robin's insurance reimbursements are significantly reduced or it experiences other adverse developments incrementally impacting the Company's related net investment or anticipated future cash flows that are not remedied through rate proceedings, the Company could potentially be required to record an impairment of its net investment in Sea Robin pursuant to FASB Statement No. 144, "*Accounting for Impairment or Disposal of Long-Lived Assets*."

Financing activities. The $45.9 million increase in financing cash inflows was primarily due to $100 million of common stock issuances in 2008 and an increase in revolving credit facilities of $124.2 million in 2008 compared to 2007, partially offset by a $110.9 million extinguishment of preferred stock, higher common stock dividends of $19.3 million in the 2008 period versus the 2007 period and lower net debt issuances of $40.5 million in 2008.

Retirement of Debt Obligations

In August 2008, the Company retired its $300 million 4.80% Senior Notes and $125 million 6.15% Senior Notes using the remaining proceeds from the 7.00% Senior Notes issued in June 2008 and draw downs of its credit facilities. See *Part I, Item 1. Financial Statements (Unaudited), Note 7 – Debt Obligations* for additional information related to issuance of the $400 million 7.00% Senior Notes and amendment of the Company's credit facilities agreements in June 2008. See *Part I, Item 1. Financial Statements (Unaudited), Note 14 – Shareholders' Equity – Preferred Stock* for additional information related to the extinguishment of the Company's outstanding Preferred Stock. See *Part I, Item 1. Financial Statements (Unaudited), Note 7 – Debt Obligations* for information related to the issuance of a $150 million short-term obligation issued in October 2008.

Credit and Short-Term Facilities

The Company has $420 million available under its credit facilities. As of October 31, 2008, there was a balance of $225 million outstanding under the Company's credit facilities, with an effective interest rate of 3.82 percent. Additionally, as of October 31, 2008, there was a balance of $150 million outstanding under the Short-Term Facility, with an effective interest rate of 4.00 percent.

OTHER MATTERS

Contingencies

See *Part I, Item 1. Financial Statements (Unaudited), Note 10 – Commitments and Contingencies*, in this Quarterly Report on Form 10-Q.

Recently Issued Accounting Standards

See *Part I, Item 1. Financial Statements (Unaudited), Note 2 – New Accounting Principles*, in this Quarterly Report on Form 10-Q.

Inflation

The Company believes that inflation has caused, and will continue to cause, increases in certain operating expenses, and will continue to require higher capital replacement and construction costs. In the Transportation and Storage and Distribution segments, the Company continually reviews the adequacy of its rates in relation to the impact of market conditions, the increasing cost of providing services and the inherent regulatory lag experienced in adjusting those rates.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The information contained in Item 3 updates, and should be read in conjunction with, related information set forth in Part II, Item 7A in the Company's Annual Report on Form 10-K for the year ended December 31, 2007, in addition to the unaudited interim condensed consolidated financial statements, accompanying notes, and Management's Discussion and Analysis of Financial Condition and Results of Operations presented in Part I, Items 1 and 2 of this Quarterly Report on Form 10-Q.

The Company had approximately $22.7 million and $18.3 million of fair value assets and liabilities, respectively, at September 30, 2008 that were measured using significant unobservable inputs (i.e. Statement No. 157 level 3 assets and liabilities). Although the Company does not have sufficient corroborative market evidence to support classifying certain level 3 assets and liabilities within level 2, the Company does not utilize significant unobservable inputs that are based on its own internal assumptions within these level 3 assets and liabilities. Rather, the Company utilizes non-binding broker quotes or third-party pricing services in determining their period-end fair value.

Interest Rate Risk

The Company is subject to the risk of loss associated with movements in market interest rates. The Company manages this risk through the use of fixed-rate debt, floating-rate debt and interest rate swaps. Fixed-rate swaps are used to reduce the risk of increased interest costs during periods of rising interest rates. Floating-rate swaps are used to convert the fixed rates of long-term borrowings into short-term variable rates. At September 30, 2008, the interest rate on 86 percent of the Company's long-term debt was fixed after considering the impact of interest rate swaps.

At September 30, 2008, $18.3 million is included in *Deferred credits* in the unaudited interim Condensed Consolidated Balance Sheet related to the fixed-rate interest rate swaps on the $455 million Term Loan due 2012.

At September 30, 2008, a 100 basis point move in the annual interest rate on all outstanding floating-rate long-term debt would increase the Company's interest payments by approximately $600,000 for each month during which such increase continued. If interest rates changed significantly, the Company would take actions to manage its exposure to the change.

The Company also enters into treasury rate locks to manage its exposure against changes in future interest payments attributable to changes in the US treasury rates. By entering into these agreements, the Company locks in an agreed upon interest rate until the settlement of the contract. The Company accounts for the treasury rate locks as cash flow hedges. The treasury locks were settled in February and June 2008.

The change in exposure to loss in earnings and cash flows related to interest rate risk for the three-month period ended September 30, 2008 is not material to the Company.

Commodity Price Risk

Gathering and Processing Segment. The Company markets natural gas and NGL in its Gathering and Processing segment and manages associated commodity price risks using both economic and accounting hedge derivative financial instruments. These instruments involve not only the risk of transacting with counterparties and their ability to meet the terms of the contracts but also the risk associated with unmatched positions and market fluctuations. The Company is required to record its commodity derivative financial instruments at fair value, which is determined by commodity exchange prices, over-the-counter quotes, volatility, time value, counterparty credit and the potential impact on market prices of liquidating positions in an orderly manner over a reasonable period of time under current market conditions.

To manage its commodity price risk related to natural gas and NGL, the Company uses a combination of puts, NGL gross processing spread puts, fixed-price physical forward sales contracts, exchange-traded futures and options, and fixed or floating index and basis swaps to manage commodity price risk. These derivative financial instruments allow the Company to preserve value and protect margins because changes in the value of the derivative financial instruments are highly effective in offsetting changes in the physical market and reducing basis risk. Basis risk exists primarily due to price differentials between cash market delivery locations and futures contract delivery locations.

The Company realizes NGL and/or natural gas volumes from the contractual arrangements associated with the gas processing services it provides. The Company utilizes various economic hedge techniques to manage its price exposure of Company owned volumes, including processing spread put options and swaps and natural gas swaps. Expected NGL and/or natural gas volumes compared to the actual volumes sold and the effectiveness of the associated economic hedges utilized by the Company can be unfavorably impacted by:

- Processing plant outages;
- Higher than anticipated fuel, flare and unaccounted for natural gas efficiency levels;
- Impact of commodity prices in general;
- Lower than expected recovery of NGL from the residue gas stream; and
- Lower than expected receipt of natural gas volumes to be processed.

The following table summarizes SUGS' principal commodity derivative instruments as of September 30, 2008 (all instruments are settled monthly), which were developed based upon operating conditions and expected equity NGL sales volumes.

Instrument Type	Index	Average Price (per MMBtu)	Volumes (MMBtu/d) 2008	Volumes (MMBtu/d) 2009	Fair Value Asset (Liability)
					(In thousands)
***Natural Gas - Cash Flow Hedges* (1)**					
Swap	IF - Waha	$ 8.01	5,525	-	$ 1,155
Swap	IF - El Paso Permian	8.01	4,475	-	935
Swap	Gas Daily - Waha	8.42	11,050	-	2,726
Swap	Gas Daily - Waha	9.49	-	11,050	8,932
Swap	Gas Daily - El Paso Permian	8.42	8,950	-	2,208
Swap	Gas Daily - El Paso Permian	9.49	-	8,950	7,235
		Total Swaps	30,000	20,000	$ 23,191
***Processing Spread - Economic Hedges* (2)**					
Put	IF - Waha	$ 8.15	6,119	-	$ 475
Put	IF - El Paso Permian	8.15	4,956	-	385
		Total Puts	11,075	-	$ 860
Swap	Gas Daily - Waha	$ 6.85	15,981	-	$ (2,836)
Swap	Gas Daily - Waha	7.40	-	16,575	1,406
Swap	Gas Daily - El Paso Permian	6.85	12,944	-	(2,297)
Swap	Gas Daily - El Paso Permian	7.40	-	13,425	1,139
		Total Swaps	28,925	30,000	$ (2,588)

(1) The Company's natural gas swap arrangements have been designated as cash flow hedges. The effective portion of changes in the fair value of the cash flow hedges is recorded in *Accumulated other comprehensive loss* until the related hedged items impact earnings. Any ineffective portion of a cash flow hedge is reported in current-period earnings.

(2) The Company's processing spread put and swap arrangements are treated as economic hedges, with the change in fair value reported in current-period earnings.

There were no up-front costs associated with the derivative instruments entered into in 2008.

Transportation and Storage Segment. The Company is exposed to commodity price risk as its interstate pipelines collect natural gas from customers for operations or as part of the fee for services provided. When the amount of natural gas utilized in operations by these pipelines differs from the amount provided by customers, the pipelines may use natural gas from inventory or could have to buy or sell natural gas to cover these operational needs, resulting in exposure to commodity price risk. At September 30, 2008, there were no hedges in place with respect to natural gas price risk from its interstate pipeline operations.

Distribution Segment. The Company has entered into natural gas commodity swaps to mitigate price volatility of natural gas passed through to customers in the Distribution segment. The cost of the derivative products and the settlement of the respective obligations are recorded through the gas purchase adjustment clause as authorized by the applicable regulatory authority and therefore do not impact earnings. The fair values of the contracts are recorded as an adjustment to a regulatory asset or liability in the unaudited interim Condensed Consolidated Balance Sheet. As of September 30, 2008 and December 31, 2007, the fair values of the contracts, which expire at various times through August 2010, are included in the unaudited interim Condensed Consolidated Balance Sheet as liabilities, with matching adjustments to deferred cost of gas of $54.6 million and $22.3 million, respectively.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures.

Southern Union has established disclosure controls and procedures to ensure that information required to be disclosed by the Company, including consolidated entities, in reports filed or submitted under the Exchange Act, is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. The Company's disclosure controls and procedures are designed to ensure that information required to be disclosed in the reports it files or submits under the Exchange Act is accumulated and communicated to management, including the Company's CEO and CFO, as appropriate, to allow timely decisions regarding required disclosure. The Company performed an evaluation under the supervision and with the participation of management, including its CEO and CFO, and with the participation of personnel from its Legal, Internal Audit, Risk Management and Financial Reporting Departments, of the effectiveness of the design and operation of the Company's disclosure controls and procedures (as defined in Exchange Act Rule 13a-15(e)) as of the end of the period covered by this report. Based on that evaluation, Southern Union's CEO and CFO concluded that the Company's disclosure controls and procedures were effective as of September 30, 2008.

Changes in Internal Controls.

Management's assessment of internal control over financial reporting as of December 31, 2007 was included in Southern Union's Annual Report on Form 10-K filed on February 29, 2008.

There have been no changes in internal control over financial reporting that occurred during the first nine months of 2008 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Cautionary Statement Regarding Forward-Looking Information

The disclosure and analysis in this Form 10-Q contains some forward-looking statements that set forth anticipated results based on management's plans and assumptions. From time to time, Southern Union also provides forward-looking statements in other materials it releases to the public as well as oral forward-looking statements. Such statements give the Company's current expectations or forecasts of future events; they do not relate strictly to historical or current facts. Southern Union has tried, wherever possible, to identify such statements by using words such as "anticipate," "estimate," "expect," "project," "intend," "plan," "believe," "will" and similar expressions in connection with any discussion of future operating or financial performance. In particular, these include statements relating to future actions, future performance or results of current and anticipated products, expenses, interest rates, the outcome of contingencies, such as legal proceedings, and financial results.

Southern Union cannot guarantee that any forward-looking statement will be realized, although management believes that the Company has been prudent in its plans and assumptions. Achievement of future results is subject to risks, uncertainties and potentially inaccurate assumptions. If known or unknown risks or uncertainties should materialize, or if underlying assumptions should prove inaccurate, actual results could differ materially from past results and those anticipated, estimated or projected. Readers should bear this in mind as they consider forward-looking statements. Southern Union undertakes no obligation publicly to update forward-looking statements, whether as a result of new information, future events or otherwise. Readers are advised, however, to consult any further disclosures the Company makes on related subjects in its Form 10-K, 10-Q and 8-K reports to the SEC. Also note that Southern Union provides the following cautionary discussion of risks, uncertainties and possibly inaccurate assumptions relevant to its businesses. These are factors that, individually or in the aggregate, management believes could cause the Company's actual results to differ materially from expected and historical results. Southern Union notes these factors for investors as permitted by the Private Securities Litigation Reform Act of 1995. Readers should understand that it is not possible to predict or identify all such factors. Consequently, readers should not consider the following to be a complete discussion of all potential risks or uncertainties.

Factors that could cause actual results to differ materially from those expressed in the Company's forward-looking statements include, but are not limited to, the following:

- changes in demand for natural gas or NGL and related services by the Company's customers, in the composition of the Company's customer base and in the sources of natural gas available to the Company;
- the effects of inflation and the timing and extent of changes in the prices and overall demand for and availability of natural gas or NGL as well as electricity, oil, coal and other bulk materials and chemicals;
- adverse weather conditions, such as warmer than normal weather in the Company's service territories, and the operational impact of natural disasters;
- changes in laws or regulations, third-party relations and approvals, decisions of courts, regulators and governmental bodies affecting or involving Southern Union, including deregulation initiatives and the impact of rate and tariff proceedings before FERC and various state regulatory commissions;
- the speed and degree to which additional competition is introduced to Southern Union's business and the resulting effect on revenues;
- the outcome of pending and future litigation;
- the Company's ability to comply with or to challenge successfully existing or new environmental regulations;
- unanticipated environmental liabilities;
- the Company's exposure to highly competitive commodity businesses through its Gathering and Processing segment;
- the Company's exposure because of limited availability of third party NGL fractionation facilities and limited availability of third party NGL transportation capacity applicable to its Gathering and Processing segment;
- the Company's ability to acquire new businesses and assets and integrate those operations into its existing operations, as well as its ability to expand its existing businesses and facilities;
- the Company's ability to control costs successfully and achieve operating efficiencies, including the purchase and implementation of new technologies for achieving such efficiencies;
- the impact of factors affecting operations such as maintenance or repairs, environmental incidents, gas pipeline system constraints and relations with labor unions representing bargaining-unit employees;
- exposure to customer concentration with a significant portion of revenues realized from a relatively small number of customers and any credit risks associated with the financial position of those customers;
- changes in the ratings of the debt securities of Southern Union or any of its subsidiaries;
- changes in interest rates and other general capital markets conditions, and in the Company's ability to continue to access the capital markets;
- acts of nature, sabotage, terrorism or other acts causing damage greater than the Company's insurance coverage limits;
- market risks beyond the Company's control affecting its risk management activities including market liquidity, commodity price volatility and counterparty creditworthiness; and
- other risks and unforeseen events.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Southern Union is a party to or has property subject to litigation and other proceedings, including matters arising under provisions relating to the protection of the environment, as described in *Part I, Item 1. Financial Statements (Unaudited), Note 10 – Commitments and Contingencies,* in this Quarterly Report on Form 10-Q and in the *Item 8. Financial Statements and Supplementary Data, Note 18 – Commitments and Contingencies,* information included in the Company's Form 10-K for the year ended December 31, 2007.

Southern Union is subject to federal and state requirements for the protection of the environment, including those for the discharge of hazardous materials and remediation of contaminated sites. As a result, Southern Union is a party to or has its property subject to various other lawsuits or proceedings involving environmental protection matters. For information regarding these matters, see *Part I, Item 1. Financial Statements (Unaudited), Note 10 – Commitments and Contingencies,* in this Quarterly Report on Form 10-Q and in the *Item 8. Financial Statements and Supplementary Data, Note 18 – Commitments and Contingencies,* information included in the Company's Form 10-K for the year ended December 31, 2007.

ITEM 1A. RISK FACTORS

There have been no material changes to the risk factors previously disclosed in the Company's Form 10-K filed with the SEC on February 29, 2008.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

The following table presents information with respect to purchases during the three months ended September 30, 2008 made by Southern Union or any "affiliated purchaser" of Southern Union (as defined in Rule 10b-18(a)(3)) of equity securities that are registered pursuant to Section 12 of the Exchange Act.

Period	Total Number of Shares Purchased (1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs (2)	Maximum Number of Shares that May Yet be Purchased Under the Publicly Announced Plans or Programs (2)
July 1, 2008 through July 31, 2008	3,211	$ 25.29	1,864,250	
August 1, 2008 through August 31, 2008	347	25.88	618,000	
September 1, 2008 through September 30, 2008	386	23.31	-	
Total	3,944	$ 25.15	2,482,250	4,798,913

(1) Shares of common stock purchased in open-market transactions and held in various Company employee benefit plan trusts by the trustees using cash amounts deferred by the participants in such plans (and quarterly cash dividends issued by the Company on shares held in such plans.)

(2) On May 22, 2008, the Company announced that the Finance Committee of its Board of Directors had authorized a program to repurchase a portion of the depositary shares representing ownership of its Preferred Stock. Repurchases are made at the Company's discretion in the open market and through privately negotiated transactions, subject to market conditions, applicable legal requirements and other factors. The Company has the right to redeem all of the Preferred Stock at any time at par after October 8, 2008. See *Part I, Item 1. Financial Statements (Unaudited), Note 14 – Stockholders' Equity*, in this Quarterly Report on Form 10-Q, for additional information related to the repurchase of depositary shares.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

N/A

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

N/A

ITEM 5. OTHER INFORMATION

All information required to be reported on Form 8-K for the quarter ended September 30, 2008 was appropriately reported.

ITEM 6. EXHIBITS

The following exhibits are filed as part of this Quarterly Report on Form 10-Q:

2(a) Purchase and Sale Agreement by and among SRCG, Ltd. and SRG Genpar, L.P., as Sellers and Southern Union Panhandle LLC and Southern Union Gathering Company LLC, as Buyers, dated as of December 15, 2005. (Filed as Exhibit 10.1 to Southern Union's Current Report on Form 8-K filed on December 16, 2005 and incorporated herein by reference.)

2(b) Purchase and Sale Agreement between Southern Union Company and UGI Corporation, dated as of January 26, 2006. (Filed as Exhibit 10.1 to Southern Union's Current Report on Form 8-K filed on January 30, 2006 and incorporated herein by reference.)

2(c) First Amendment to the Purchase and Sale Agreement between Southern Union Company and UGI Corporation, dated as of August 24, 2006. (Filed as Exhibit 10.1 to Southern Union's Current Report on Form 8-K filed on August 30, 2006 and incorporated herein by reference.)

2(d) Purchase and Sale Agreement between Southern Union Company and National Grid USA, dated as of February 15, 2006. (Filed as Exhibit 10.1 to Southern Union's Current Report on Form 8-K filed on February 17, 2006 and incorporated herein by reference.)

2(e) Limited Settlement Agreement between Southern Union Company, Narragansett Electric Company d/b/a National Grid, the Department of the Attorney General for the State of Rhode Island and the Rhode Island Department of Environmental Management, dated as of August 24, 2006. (Filed as Exhibit 10.2 to Southern Union's Current Report on Form 8-K filed on August 30, 2006 and incorporated herein by reference.)

2(f) First Amendment to the Purchase and Sale Agreement between Southern Union Company and National Grid USA, dated as of August 24, 2006. (Filed as Exhibit 10.3 to Southern Union's Current Report on Form 8-K filed on August 30, 2006 and incorporated herein by reference.)

2(g) Redemption Agreement by and between CCE Holdings, LLC and Energy Transfer Partners, L.P., dated as of September 18, 2006. (Filed as Exhibit 10.1 to Southern Union's Current Report on Form 8-K filed on September 18, 2006 and incorporated herein by reference.)

2(h) Letter Agreement by and between Southern Union Company and Energy Transfer Partners, L.P., dated as of September 14, 2006. (Filed as Exhibit 10.2 to Southern Union's Current Report on Form 8-K filed on September 18, 2006 and incorporated herein by reference.)

3(a) Amended and Restated Certificate of Incorporation of Southern Union Company. (Filed as Exhibit 3(a) to Southern Union's Annual Report on Form 10-K filed on March 16, 2006 and incorporated herein by reference.)

3(b) By-Laws of Southern Union Company, as amended through January 3, 2007. (Filed as Exhibit 3.1 to Southern Union's Current Report on Form 8-K filed on January 3, 2007 and incorporated herein by reference.)

3(c) Certificate of Designations, Preferences and Rights re: Southern Union Company's 7.55% Noncumulative Preferred Stock, Series A. (Filed as Exhibit 4.1 to Southern Union's Form 8-A/A dated October 17, 2003 and incorporated herein by reference.)

4(a) Specimen Common Stock Certificate. (Filed as Exhibit 4(a) to Southern Union's Annual Report on Form 10-K for the year ended December 31, 1989 and incorporated herein by reference.)

4(b) Indenture between The Bank of New York Trust Company, N.A., as successor to Chase Manhattan Bank, N.A., as trustee, and Southern Union Company dated January 31, 1994. (Filed as Exhibit 4.1 to Southern Union's Current Report on Form 8-K dated February 15, 1994 and incorporated herein by reference.)

4(c) Officers' Certificate dated January 31, 1994 setting forth the terms of the 7.60% Senior Debt Securities due 2024. (Filed as Exhibit 4.2 to Southern Union's Current Report on Form 8-K dated February 15, 1994 and incorporated herein by reference.)

4(d) Officer's Certificate of Southern Union Company dated November 3, 1999 with respect to 8.25% Senior Notes due 2029. (Filed as Exhibit 99.1 to Southern Union's Current Report on Form 8-K filed on November 19, 1999 and incorporated herein by reference.)

4(e) Form of Supplemental Indenture No. 1, dated June 11, 2003, between Southern Union Company and The Bank of New York Trust Company, N.A., as successor to JP Morgan Chase Bank (formerly the Chase Manhattan Bank, National Association). (Filed as Exhibit 4.5 to Southern Union's Form 8-A/A dated June 20, 2003 and incorporated herein by reference.)

4(f) Supplemental Indenture No. 2, dated February 11, 2005, between Southern Union Company and The Bank of New York Trust Company, N.A., as successor to JP Morgan Chase Bank, N.A. (f/n/a JP Morgan Chase Bank). (Filed as Exhibit 4.4 to Southern Union's Form 8-A/A dated February 22, 2005 and incorporated herein by reference.)

4(g) Subordinated Debt Securities Indenture between Southern Union Company and The Bank of New York Trust Company, N.A., as successor to JP Morgan Chase Bank (as successor to The Chase Manhattan Bank, N.A.), as Trustee. (Filed as Exhibit 4-G to Southern Union's Registration Statement on Form S-3 (No. 33-58297) and incorporated herein by reference.)

4(h) Second Supplemental Indenture, dated October 23, 2006, between Southern Union Company and The Bank of New York Trust Company, N.A., successor to JP Morgan Chase Bank, N.A., formerly known as JPMorgan Chase Bank, formerly known as The Chase Manhattan Bank (National Association). (Filed as Exhibit 4.1 to Southern Union's Form 8-K/A dated October 24, 2006 and incorporated herein by reference.)

4(i) 2006 Series A Junior Subordinated Notes Due November 1, 2066 dated October 23, 2006. (Filed as Exhibit 4.2 to Southern Union's Current Report on Form 8-K/A filed on October 24, 2006 and incorporated herein by reference.)

4(j) Replacement Capital Covenant, dated as of October 23, 2006 by Southern Union Company, a Delaware corporation with its successors and assigns, in favor of and for the benefit of each Covered Debtor (as defined in the Covenant). (Filed as Exhibit 4.3 to Southern Union's Current Report on Form 8-K/A filed on October 24, 2006 and incorporated herein by reference.)

4(k) Southern Union is a party to other debt instruments, none of which authorizes the issuance of debt securities in an amount which exceeds 10% of the total assets of Southern Union. Southern Union hereby agrees to furnish a copy of any of these instruments to the Commission upon request.

10(a) First Amendment to Construction and Term Loan Agreement between Citrus Corp., as borrower, and Pipeline Funding Company, LLC, as lender and administrative agent, dated as of August 6, 2008. (Filed as Exhibit 10(a) to Southern Union Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2008 and incorporated herein by reference.)

10(b) Construction and Term Loan Agreement between Citrus Corp., as borrower, and Pipeline Funding Company, LLC, as lender and administrative agent, dated as of February 5, 2008. (Filed as Exhibit 10.1 to Southern Union's Current Report on Form 8-K filed on February 8, 2008 and incorporated herein by reference.)

10(c) Amended and Restated Credit Agreement between Trunkline LNG Holdings, LLC, as borrower, Panhandle Eastern Pipeline Company, LP and CrossCountry Citrus, LLC, as guarantors, the financial institutions listed therein Bayerische Hypo-Und Vereinsbank AG, New York Branch, as administrative agent, dated as of June 29, 2007. (Filed as Exhibit 10.1 to Southern Union's Current Report on Form 8-K filed on July 6, 2007 and incorporated herein by reference.)

10(d) Amendment Number 1 to the Amended and Restated Credit Agreement between Trunkline LNG Holdings, LLC, as borrower, Panhandle Eastern Pipe Line Company, LP and CrossCountry Citrus, LLC, as guarantors, the financial institutions listed therein and Bayerische Hypo-Und Vereinsbank AG, New York Branch, as administrative agent, dated as of June 13, 2008. (Filed as Exhibit 10(d) to Southern Union Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2008 and incorporated herein by reference.)

10(e) Fifth Amended and Restated Revolving Credit Agreement, dated as of June 20, 2008, among the Company, as borrower, and the lenders party thereto. (Filed as Exhibit 10.1 to Southern Union's Current Report on Form 8-K filed on June 25, 2008 and incorporated herein by reference.)

10(f) Employment Agreement between Southern Union Company and George L. Lindemann, dated as of August 28, 2008. (Filed herewith as Exhibit 10(f).)

10(g) Employment Agreement between Southern Union Company and Eric D. Herschmann, dated as of August 28, 2008. (Filed herewith as Exhibit 10(g).)

10(h) Employment Agreement between Southern Union Company and Robert O. Bond, dated as of August 28, 2008. (Filed herewith as Exhibit 10(h).)

10(i) Employment Agreement between Southern Union Company and Monica M. Gaudiosi, dated as of August 28, 2008. (Filed herewith as Exhibit 10(i).)

10(j) Employment Agreement between Southern Union Company and Richard N. Marshall, dated as of August 28, 2008. (Filed herewith as Exhibit 10(j).)

10(k) Form of Employment Agreement between Southern Union Company and certain Executives (filed as Exhibit 10.1 to Southern Union's Current Report on
Form 8-K filed on August 28, 2008 and incorporated herein by reference.)

10(l) Form of Change in Control Severance Agreement, between Southern Union Company and certain Executives (filed as Exhibit 10.2 to Southern Union's Current Report on
Form 8-K filed on August 28, 2008 and incorporated herein by reference.)

10(m) Credit Agreement between Trunkline LNG Holdings, LLC, as borrower, Panhandle Eastern Pipeline Company, LP and Trunkline LNG Company, LLC, as guarantors,
the financial institutions listed therein and Hypo-Und Vereinsbank AG, New York Branch, as administrative agent, dated as of March 15, 2007. (Filed as Exhibit 10.1 to
Southern Union's Current Report on Form 8-K filed on March 21, 2007 and incorporated herein by reference.)

10(n) Form of Indemnification Agreement between Southern Union Company and each of the Directors of Southern Union Company. (Filed as Exhibit 10(i) to Southern Union's Annual Report on Form 10-K for the year ended December 31, 1986 and incorporated herein by reference.)

10(o) Southern Union Company 1992 Long-Term Stock Incentive Plan, As Amended. (Filed as Exhibit 10(l) to Southern Union's Annual Report on Form 10-K for the year ended June 30, 1998 and incorporated herein by reference.)

10(p) Southern Union Company Director's Deferred Compensation Plan. (Filed as Exhibit 10(g) to Southern Union's Annual Report on Form 10-K for the year ended December 31, 1993 and incorporated herein by reference.)

10(q) First Amendment to Southern Union Company Director's Deferred Compensation Plan, effective April 1, 2007. (Filed as Exhibit 10(h) to Southern Union Company's Quarterly Report for the quarter ended September 30, 2007 and incorporated herein by reference.)

10(r) Southern Union Company Amended Supplemental Deferred Compensation Plan with Amendments. (Filed as Exhibit 4 to Southern Union's Form S-8 filed May 27, 1999 and incorporated herein by reference.)

10(s) Separation Agreement and General Release Agreement between Thomas F. Karam and Southern Union Company dated November 8, 2005. (Filed as Exhibit 10.1 to Southern Union's Current Report on Form 8-K filed on November 8, 2005 and incorporated herein by reference.)

10(t) Separation Agreement and General Release Agreement between John E. Brennan and Southern Union Company dated July 1, 2005. (Filed as Exhibit 10.1 to Southern Union's Current Report on Form 8-K filed on July 5, 2005 and incorporated herein by reference.)

10(u) Separation Agreement and General Release Agreement between David J. Kvapil and Southern Union Company dated July 1, 2005. (Filed as Exhibit 10.4 to Southern Union's Current Report on Form 8-K filed on July 5, 2005 and incorporated herein by reference.)

10(v) Second Amended and Restated Southern Union Company 2003 Stock and Incentive Plan. (Filed as Exhibit 4 to Form S-8, SEC File No. 333-138524, filed on November 8, 2006 and incorporated herein by reference.)

10(w) Southern Union Company Pennsylvania Division Stock Incentive Plan. (Filed as Exhibit 4 to Form S-8, SEC File No. 333-36146, filed on May 3, 2000 and incorporated herein by reference.)

10(x) Southern Union Company Pennsylvania Division 1992 Stock Option Plan. (Filed as Exhibit 4 to Form S-8, SEC File No. 333-36150, filed on May 3, 2000 and incorporated herein by reference.)

10(y) Form of Long Term Incentive Award Agreement, dated December 28, 2006, between Southern Union Company and the undersigned. (Filed as Exhibit 99.1 to Southern Union's Form 8-K dated January 3, 2007) and incorporated herein by reference.)

10(z) Capital Stock Agreement dated June 30, 1986, as amended April 3, 2000 ("Agreement"), among El Paso Energy Corporation (as successor in interest to Sonat, Inc.);
CrossCountry Energy, LLC (assignee of Enron Corp., which is the successor in interest to InterNorth, Inc. by virtue of a name change and successor in interest to
Houston Natural Gas Corporation by virtue of a merger) and Citrus Corp. (Filed as Exhibit 10(p) to Southern Union's Form 10-K dated March 1, 2007 and incorporated
herein by reference.)

10(aa) Certificate of Incorporation of Citrus Corp. (Filed as Exhibit 10(q) to Southern Union's Form 10-K dated March 1, 2007 and incorporated herein by reference.)

10(bb) By-Laws of Citrus Corp., filed herewith. (Filed as Exhibit 10(r) to Southern Union's Form 10-K dated March 1, 2007 and incorporated herein by reference.)

12 Ratio of earnings to fixed charges.

14 Code of Ethics and Business Conduct. (Filed as Exhibit 14 to Southern Union's Annual Report on Form 10-K filed on March 16, 2006 and incorporated herein by reference.)

21 Subsidiaries of the Registrant. (Filed as Exhibit 21 to Southern Union's Annual Report on Form 10-K filed on February 29, 2008 and incorporated herein by reference.)

31.1 Certificate by Chief Executive Officer pursuant to Rule 13a-14(a) or Rule 15d-14(a) promulgated under the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.2 Certificate by Chief Financial Officer pursuant to Rule 13a-14(a) or Rule 15d-14(a) promulgated under the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32.1 Certificate by Chief Executive Officer pursuant to Rule 13a-14(b) or Rule 15d-14(b) promulgated under the Securities Exchange Act of 1934 and Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350.

32.2 Certificate by Chief Financial Officer pursuant to Rule 13a-14(b) or Rule 15d-14(b) promulgated under the Securities Exchange Act of 1934 and Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

SOUTHERN UNION COMPANY
(Registrant)

Date: November 10, 2008

By /s/ GEORGE E. ALDRICH
George E. Aldrich
Vice President and Controller
(authorized officer and principal accounting officer)

Docket No. RP09-_____-000
Exhibit No. HIO-74
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10-K 1 suform10k_123107.htm SOUTHERN UNION COMPANY FORM 10-K, DECEMBER 31, 2007

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D. C. 20549

FORM 10-K

_X ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the Fiscal Year Ended December 31, 2007

OR

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 FOR THE TRANSITION PERIOD FROM

Commission File No. 1-6407

SOUTHERN UNION COMPANY
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**75-0571592** (I.R.S. Employer Identification No.)
5444 Westheimer Road **Houston, Texas** (Address of principal executive offices)	**77056-5306** (Zip Code)

Registrant's telephone number, including area code: **(713) 989-2000**

Securities Registered Pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, par value $1 per share	**New York Stock Exchange**
7.55% Depositary Shares	**New York Stock Exchange**
5.00% Corporate Units	**New York Stock Exchange**

Securities Registered Pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes **P** No ____

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
Yes ____ No **P**

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes **P** No ____

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. **P**

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act. (Check one):
Large accelerated filer **P** Accelerated filer _____ Non-accelerated filer _____ Smaller reporting company _____

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act).
Yes ____ No **P**

The aggregate market value of the Common Stock held by non-affiliates of the Registrant as of June 30, 2007 was $3,537,812,559 (based on the closing sales price of Common Stock on the New York Stock Exchange on June 30, 2007). For purposes of this calculation, shares held by non-affiliates exclude only those shares beneficially owned by executive officers, directors and stockholders of more than 10% of the Common Stock of the Company.

The number of shares of the registrant's Common Stock outstanding on February 22, 2008 was 123,772,513.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant’s proxy statement for its annual meeting of stockholders that is scheduled to be held on May 13, 2008 are incorporated by reference into Part III.

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SOUTHERN UNION COMPANY AND SUBSIDIARIES
FORM 10-K
DECEMBER 31, 2007

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PART I

ITEM 1. Business.

OUR BUSINESS

Introduction

Southern Union Company (*Southern Union* and, together with its subsidiaries, the *Company*) was incorporated under the laws of the State of Delaware in 1932. The Company owns and operates assets in the regulated and unregulated natural gas industry and is primarily engaged in the gathering, processing, transportation, storage and distribution of natural gas in the United States. The Company operates in three reportable segments: Transportation and Storage, Gathering and Processing, and Distribution.

BUSINESS SEGMENTS

Reportable Segments

The Company's operations, as reported, include three reportable segments:

- The Transportation and Storage segment, which is primarily engaged in the interstate transportation and storage of natural gas from gas producing areas in Texas, Oklahoma, Colorado, the Gulf of Mexico and the Gulf Coast to markets throughout the Midwest and from the Gulf Coast to Florida, and liquefied natural gas (*LNG*) terminalling and regasification services. Its operations are currently conducted through Panhandle Eastern Pipe Line Company, LP (*PEPL*) and its subsidiaries (collectively *Panhandle*) and its 50 percent equity ownership interest in Florida Gas Transmission Company, LLC (*Florida Gas*) through Citrus Corp. (*Citrus*);

- The Gathering and Processing segment, which is primarily engaged in the gathering, treating, processing and redelivery of natural gas and natural gas liquids (*NGLs*) in Texas and New Mexico. Its operations are conducted through Southern Union Gas Services (*SUGS*); and

- The Distribution segment, which is primarily engaged in the local distribution of natural gas in Missouri and Massachusetts. Its operations are conducted through Missouri Gas Energy and New England Gas Company.

The Company has other operations that support and expand its natural gas and other energy sales, which are not included in its reportable segments. These operations do not meet the quantitative thresholds for determining reportable segments and have been combined for disclosure purposes in the *Corporate and Other* category. For information about the revenues, operating income, assets and other financial information relating to the Corporate and Other category, see *Item 8. Financial Statements and Supplementary Data, Note 21 – Reportable Segments*.

The Company also provides various corporate services to support its operating businesses, including executive management, accounting, communications, human resources, information technology, insurance, internal audit, investor relations, environmental, legal, payroll, purchasing, risk management, tax and treasury.

Sales of products or services between segments are billed at regulated rates or at market rates, as applicable. There were no material intersegment revenues during the years ended December 31, 2007, 2006 or 2005.

Transportation and Storage Segment

Services

The Transportation and Storage segment is primarily engaged in the interstate transportation and storage of natural gas to the Midwest and from the Gulf Coast to Florida, and LNG terminalling and regasification services. The Transportation and Storage segment's operations are conducted through Panhandle and Florida Gas.

For the years ended December 31, 2007, 2006 and 2005, the Transportation and Storage segment's operating revenues were $658.4 million, $577.2 million and $505.2 million, respectively. *Earnings from unconsolidated investments* related to Citrus were $98.9 million for the year ended December 31, 2007. For the years ended December 31, 2006 and 2005, *Earnings from unconsolidated investments* contributed through CCE Holdings,

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LLC (*CCE Holdings*) were $141.1 million and $70.4 million, respectively. See discussion below in *Citrus and CCE Holdings* related to the Company's increased ownership interest in Florida Gas through Citrus effective December 1, 2006.

For information about operating revenues, earnings before interest and taxes (*EBIT*), earnings from unconsolidated investments, assets and other financial information relating to the Transportation and Storage segment, see *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations – Business Segment Results – Transportation and Storage* and *Item 8. Financial Statements and Supplementary Data, Note 21 – Reportable Segments.*

Panhandle. Panhandle owns and operates a large natural gas open-access interstate pipeline network. The pipeline network, consisting of the PEPL transmission system, the Trunkline Gas Company, LLC (*Trunkline*) transmission system and the Sea Robin Pipeline Company, LLC (*Sea Robin*) transmission system, serves customers in the Midwest with a comprehensive array of transportation and storage services. PEPL's transmission system consists of four large diameter pipelines extending approximately 1,300 miles from producing areas in the Anadarko Basin of Texas, Oklahoma and Kansas through Missouri, Illinois, Indiana, Ohio and into Michigan. Trunkline's transmission system consists of two large diameter pipelines extending approximately 1,400 miles from the Gulf Coast areas of Texas and Louisiana through Arkansas, Mississippi, Tennessee, Kentucky, Illinois and Indiana to a point on the Indiana-Michigan border. Sea Robin's transmission system consists of two offshore Louisiana natural gas supply systems extending approximately 81 miles into the Gulf of Mexico. In connection with its gas transmission and storage systems, Panhandle has five gas storage fields located in Illinois, Kansas, Louisiana, Michigan and Oklahoma. Pan Gas Storage, LLC (d.b.a. *Southwest Gas Storage*) operates four of these fields and Trunkline operates one. Through Trunkline LNG Company, LLC (*Trunkline LNG*), Panhandle owns and operates an LNG terminal in Lake Charles, Louisiana. The Trunkline LNG terminal is one of the largest operating LNG facilities in North America based on its current sustainable send out capacity of approximately 1.8 billion cubic feet per day (*Bcf/d*).

Panhandle earns most of its revenue by entering into firm transportation and storage contracts, reserving capacity for customers to transport or store natural gas or LNG, in its facilities. Approximately 34 percent of Panhandle's total operating revenue comes from long-term service agreements with local distribution company customers and their affiliates. Panhandle also provides firm transportation services under contract to gas marketers, producers, other pipelines, electric power generators and a variety of end-users. Panhandle's pipelines offer both firm and interruptible transportation to customers on a short-term or seasonal basis. Demand for gas transmission on Panhandle's pipeline systems is seasonal, with the highest throughput and a higher portion of annual total operating revenues and net earnings occurring in the traditional winter heating season in the first and fourth calendar quarters.

Citrus and CCE Holdings. On December 1, 2006, the Company completed a series of transactions that resulted in it increasing its effective ownership interest in Florida Gas from 25 percent to 50 percent and eliminating its effective 50 percent ownership interest in Transwestern Pipeline Company, LLC (*Transwestern*). On September 14, 2006, Energy Transfer Partners, LP. (*Energy Transfer*) entered into a definitive purchase agreement to acquire the 50 percent interest in CCE Holdings, LLC (*CCE Holdings*) held by GE Energy Financial Services and other investors. At the same time, Energy Transfer and CCE Holdings entered into a definitive redemption agreement (*Redemption Agreement*), pursuant to which Energy Transfer's 50 percent ownership interest in CCE Holdings would be redeemed in exchange for 100 percent of the equity interests in Transwestern. Upon closing of the Redemption Agreement on December 1, 2006, the Company became the sole owner of 100 percent of CCE Holdings, whose principal remaining asset was its 50 percent interest in Citrus which, in turn, owns 100 percent of Florida Gas.

Florida Gas is an open-access interstate pipeline system with a mainline capacity of 2.1 Bcf/d extending approximately 5,000 miles from south Texas through the Gulf Coast region of the United States to south Florida. Florida Gas' pipeline system primarily receives natural gas from natural gas producing basins along the Louisiana and Texas Gulf Coast, Mobile Bay and offshore Gulf of Mexico. Florida Gas is the principal transporter of natural gas to the Florida energy market, delivering over 70 percent of the natural gas consumed in the state. In addition, Florida Gas' pipeline system operates and maintains 60 interconnects with major interstate and intrastate natural gas pipelines, which provide Florida Gas' customers access to diverse natural gas producing regions.

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Florida Gas earns the majority of its revenue by entering into firm transportation contracts, providing capacity for customers to transport natural gas in their pipelines. Florida Gas also earns variable revenue from charges assessed on each unit of transportation provided.

Demand for gas transmission service on the Florida Gas pipeline system is somewhat seasonal, with the highest throughput and related net earnings occurring in the summer period due to gas-fired generation loads in the second and third calendar quarters. The Company's share of net earnings of Florida Gas and, until its transfer on December 1, 2006, Transwestern have been reported in *Earnings from unconsolidated investments* in the Consolidated Statement of Operations.

The following table provides a summary of transportation volumes (in trillion British thermal units) associated with the reported results of operations for the periods presented:

	Year Ended December 31, 2007	Year Ended December 31, 2006	Year Ended December 31, 2005
Panhandle			
PEPL	662	579	609
Trunkline	648	486	459
Sea Robin	144	115	146
Trunkline LNG Usage Volumes	261	149	108
Citrus and CCE Holdings (1)			
Florida Gas	751	737	699
Transwestern	N/A	572 (2)	589

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(1) Represents 100 percent of Transwestern and Florida Gas versus the Company's effective equity ownership interest. The Company's effective equity ownership interests in Transwestern and Florida Gas were 50 percent and 25 percent, respectively, until December 1, 2006, when the Company's interest in Transwestern was transferred to Energy Transfer, increasing the Company's effective interest in Florida Gas to 50 percent.

(2) Represents transportation volumes for Transwestern for the eleven-month period ended November 30, 2006.

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The following table provides a summary of certain statistical information associated with Panhandle and Florida Gas at December 31, 2007:

	As of December 31, 2007
Panhandle	
Approximate Miles of Pipelines	
PEPL	6,000
Trunkline	3,500
Sea Robin	400
Peak Day Delivery Capacity (Bcf/d)	
PEPL	2.8
Trunkline	1.7
Sea Robin	1.0
Trunkline LNG	2.1
Trunkline LNG Sustainable Send Out Capacity (Bcf/d)	1.8
Underground Storage Capacity-Owned (Bcf)	74.4
Underground Storage Capacity-Leased (Bcf)	19.9
Trunkline LNG Terminal Storage Capacity (Bcf)	9.0
Average Number of Transportation Customers	500
Weighted Average Remaining Life in Years of Firm Transportation Contracts	
PEPL	4.6
Trunkline	9.0
Sea Robin (1)	N/A
Weighted Average Remaining Life in Years of Firm Storage Contracts	
PEPL	5.9
Trunkline	3.1
Florida Gas (2)	
Approximate Total Miles of Pipelines	5,000
Peak Day Delivery Capacity (Bcf/d)	2.3
Average Number of Transportation Customers	125
Weighted Average Remaining Life of Firm Transportation Contracts	8.7

(1) Sea Robin's contracts are primarily interruptible, with only one firm contract in place.
(2) Represents 100 percent of Florida Gas versus the Company's effective equity ownership interest of 50 percent at December 31, 2007.

Recent System Enhancements – Completed or Under Construction

LNG Terminal Enhancement. The Company has commenced construction of an enhancement at its Trunkline LNG terminal. This infrastructure enhancement project, which was originally expected to cost approximately $250 million, plus capitalized interest, will increase send out flexibility at the terminal and lower fuel costs. Recent cost projections indicate the construction costs will likely be approximately $365 million, plus capitalized interest. The revised costs reflect increases in the quantities and cost of materials required, higher contract labor costs and an allowance for additional contingency funds, if needed. The negotiated rate with the project's customer, BG LNG Services, will be adjusted based on final capital costs pursuant to a contract-based formula. The project is now expected to be in operation in the second quarter of 2009. In addition, Trunkline LNG and BG LNG Services agreed to extend the existing terminal and pipeline services agreements through 2028, representing a five-year extension. Approximately $178.3 million and $40.8 million of costs are included in the line item *Construction work-in-progress* at December 31, 2007 and 2006, respectively.

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Compression Modernization. The Company has received approval from FERC to modernize and replace various compression facilities on PEPL. Such replacements are ultimately expected to be made at eleven compressor stations, with three stations completed as of December 31, 2007. Three additional stations are in progress and planned to be completed by the end of 2009, with the remaining cost for these stations estimated at approximately $100 million, plus capitalized interest. Planning for the other five compressor stations on which construction has not yet begun is continuing, with the timing and scope of the work on these stations being evaluated on an individual station basis. The Company is also replacing approximately 32 miles of existing pipeline on the east end of the PEPL system at a current estimated cost of approximately $125 million, plus capitalized interest, which will further improve system integrity and reliability. The revised higher cost relates to various construction issues and delays which have resulted in current estimated in-service dates for the related facilities around the end of the first quarter of 2008 or in the second quarter of 2008. Approximately $124.7 million and $57.9 million of costs related to these projects are included in the line item *Construction work-in-progress* at December 31, 2007 and December 31, 2006, respectively.

Trunkline Field Zone Expansion Project. Trunkline has completed construction on its field zone expansion project. The expansion project included the north Texas expansion and creation of additional capacity on Trunkline's pipeline system in Texas and Louisiana to increase deliveries to Henry Hub. Trunkline has increased the capacity along existing rights-of-way from Kountze, Texas to Longville, Louisiana by approximately 625 million cubic feet per day (*MMcf/d*) with the construction of approximately 45 miles of 36-inch diameter pipeline. The project included horsepower additions and modifications at existing compressor stations. Trunkline has also created additional capacity to Henry Hub with the construction of a 13.5-mile, 36-inch diameter pipeline loop from Kaplan, Louisiana directly into Henry Hub. The Henry Hub lateral provides capacity of 1 Bcf/d from Kaplan, Louisiana to Henry Hub. The majority of the project was put into service in late December 2007 with the remainder placed in-service in February 2008. The Company currently estimates the final project costs will total approximately $250 million, plus capitalized interest. The estimated costs include a $40 million contribution in aid of construction (*CIAC*) to a subsidiary of Energy Transfer, which was paid in January 2008 and is expected to be amortized over the life of the facilities. Approximately $26.4 million and $12.5 million of costs for this project are included in the line item *Construction work-in-progress* at December 31, 2007 and 2006, respectively, with $178.3 million closed to *Plant in service* in December 2007.

Significant Customers

The following table provides the percentage of Transportation and Storage segment *Operating revenues* and related weighted average contract lives of Panhandle's significant customers at December 31, 2007:

Customer	Percent of Segment Revenues For Year Ended December 31, 2007 (1)	Weighted Average Life of Contracts at December 31, 2007
BG LNG Services	28%	16 years (LNG, transportation)
ProLiance	11	5.2 years (transportation) 6.9 years (storage)
Other top 10 customers	26	N/A
Remaining customers	35	N/A
Total percentage	100%	

(1) Panhandle has no single customer, or group of customers under common control, that accounted for ten percent or more of the Company's total consolidated operating revenues.

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Panhandle's customers are subject to change during the year as a result of capacity release provisions that allow current customers to release all or part of their capacity, which generally occurs for a limited time period. Under the terms of Panhandle's tariffs, a temporary capacity release does not relieve the original customer from its payment obligations if the replacement customer fails to pay.

The following table provides information related to Florida Gas' significant customers at December 31, 2007:

Customer	**Percent of Florida Gas' Total Operating Revenues For Year Ended December 31, 2007 (1)**	**Weighted Average Life of Contracts at December 31, 2007**
Florida Power & Light	40%	7.3 Years
Tampa Electric/Peoples Gas	16	9.6 Years
Other top 10 customers	28	N/A
Remaining customers	16	N/A
Total percentage	100%	

(1) The Company accounts for its investment in Florida Gas through its equity investment in Citrus using the equity method. Accordingly, it reports its share of Florida Gas' net earnings within *Earnings from unconsolidated investments* in the Consolidated Statement of Operations.

Regulation and Rates

Panhandle and Florida Gas are subject to regulation by various federal, state and local governmental agencies, including those specifically described below. See also *Item 1A. Risk Factors – Risks That Relate to the Company's Transportation and Storage Segment* and *Item 8. Financial Statements and Supplementary Data, Note 16 – Regulation and Rates.*

FERC has comprehensive jurisdiction over PEPL, Trunkline, Sea Robin, Trunkline LNG, Southwest Gas Storage and Florida Gas as natural gas companies within the meaning of the Natural Gas Act of 1938. For natural gas companies, FERC's jurisdiction relates, among other things, to the acquisition, operation and disposition of assets and facilities and to the service provided and rates charged.

FERC has authority to regulate rates and charges for transportation and storage of natural gas in interstate commerce. FERC also has authority over the construction and operation of pipeline and related facilities utilized in the transportation and sale of natural gas in interstate commerce, including the extension, enlargement or abandonment of service using such facilities. PEPL, Trunkline, Sea Robin, Trunkline LNG, Southwest Gas Storage and Florida Gas hold certificates of public convenience and necessity issued by FERC, authorizing them to construct and operate the pipelines, facilities and properties now in operation for which such certificates are required, and to transport and store natural gas in interstate commerce.

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The following table summarizes the status of the rate proceedings applicable to the Transportation and Storage segment as of December 31, 2007:

Company	Date of Last Rate Filing	Status
PEPL	May 1992	Settlement effective April 1997
Trunkline	January 1996	Settlement effective May 2001
Sea Robin	June 2007	Ongoing; procedural schedule currently suspended (1)
Trunkline LNG	June 2001	Settlement effective January 2002 (2)
Southwest Gas Storage	August 2007	Settlement approved February 2008
Florida Gas	October 2003	Settlement effective March 2005; rate moratorium in effect until October 2007; required to file by October 2009

(1) Filed rates put into effect January 1, 2008, subject to refund.
(2) Settlement provides for a rate moratorium through 2015.

Panhandle and Florida Gas are also subject to the Natural Gas Pipeline Safety Act of 1968 and the Pipeline Safety Improvement Act of 2002, which regulate the safety of gas pipelines.

For a discussion of the effect of certain FERC orders on Panhandle, see *Item 8. Financial Statements and Supplementary Data, Note 16 – Regulation and Rates – Panhandle.*

Competition

The interstate pipeline systems of Panhandle and Florida Gas compete with those of other interstate and intrastate pipeline companies in the transportation and storage of natural gas. The principal elements of competition among pipelines are rates, terms of service, flexibility and reliability of service.

Natural gas competes with other forms of energy available to the Company's customers and end-users, including electricity, coal and fuel oils. The primary competitive factor is price. Changes in the availability or price of natural gas and other forms of energy, the level of business activity, conservation, legislation and governmental regulation, the capability to convert to alternate fuels and other factors, including weather and natural gas storage levels, affect the ongoing demand for natural gas in the areas served by Panhandle and Florida Gas.

Federal and state regulation of natural gas interstate pipelines has changed dramatically in the last two decades and could continue to change over the next several years. These regulatory changes have resulted, and will likely continue to result, in increased competition in the pipeline business. In order to meet competitive challenges, Panhandle and Florida Gas will need to adapt their marketing strategies, the type of transportation and storage services provided and their pricing and rate responses to competitive forces. Panhandle and Florida Gas will also need to respond to changes in state regulation in their market areas that allow direct sales to all retail end-user customers or, at a minimum, broader customer classes than now allowed.

FERC may authorize the construction of new interstate pipelines that are competitive with existing pipelines. A number of new pipeline and pipeline expansion projects are under development to transport large additional volumes of natural gas to the Midwest from the Rockies. These pipelines, which include Kinder Morgan's Rockies Express Pipeline project, could potentially compete with the Company.

The Company's direct competitors include Alliance Pipeline LP, ANR Pipeline Company, Natural Gas Pipeline Company of America, ONEOK Partners, Texas Gas Transmission Corporation, Northern Natural Gas Company, Vector Pipeline, Columbia Gulf Transmission and Midwestern Gas Transmission.

Florida Gas competes in peninsular Florida with Gulfstream, a joint venture of Spectra Energy Corporation and The Williams Companies. Florida Gas also serves the Florida panhandle, where it competes with Gulf South Pipeline Company and the natural gas transportation business of Southern Natural Gas. Florida Gas faces competition, to a lesser degree, from alternate fuels, including residual fuel oil, in the Florida market, as well as from proposed LNG regasification facilities.

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Gathering and Processing Segment

Services

SUGS' operations consist of a network of approximately 4,800 miles of natural gas and NGLs pipelines, four active cryogenic processing plants with a combined capacity of 410 MMcf/d and five active natural gas treating plants with a combined capacity of 470 MMcf/d. The principal assets of SUGS are located in the Permian Basin of Texas and New Mexico.

SUGS is primarily engaged in connecting wells of natural gas producers to its gathering system, treating natural gas to remove impurities to meet pipeline quality specifications, processing natural gas for the removal of NGLs, and redelivering natural gas and NGLs to a variety of markets. SUGS gathers and processes natural gas for approximately 240 customers. Its primary sales customers include producers, power generating companies, utilities, energy marketers, and industrial users located primarily in the southwestern United States. SUGS receives natural gas for purchase or gathering and redelivery to market from more than 240 producers and suppliers. SUGS' business is not generally seasonal in nature.

As a result of the operational flexibility built into SUGS' gathering system and plants, it is able to offer a broad array of services to producers, including:

- field gathering and compression of natural gas for delivery to its plants;
- treating, dehydration, sulfur recovery and other conditioning; and
- natural gas processing and marketing of products.

For the year 2007 and the 2006 period subsequent to the March 1, 2006 acquisition, SUGS' gross margin (*Operating revenues* net of *Cost of gas and other energy)* were $210.8 million and $172.2 million, respectively. For information about operating revenues, EBIT, assets and other financial information relating to the Gathering and Processing segment, see *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations – Business Segment Results – Gathering and Processing* and *Item 8. Financial Statements and Supplementary Data, Note 21 – Reportable Segments*.

Significant Customers

The following table provides the percentage of Gathering and Processing segment *Operating revenues* and related weighted average contract lives of SUGS' significant customers at December 31, 2007:

Customer	**Percent of Segment Revenues For Year Ended December 31, 2007**	**Weighted Average Life of Firm Contracts at December 31, 2007**
ConocoPhillips Company (1)	16%	Month-to-Month
Other top 10 customers	47	N/A
Remaining customers	37	N/A
Total percentage	100%	

(1) SUGS has no single customer, or group of customers under common control, that accounted for ten percent or more of the Company's total consolidated operating revenues.

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Natural Gas Connections

SUGS' major natural gas pipeline interconnects are with ATMOS Pipeline Texas, El Paso Natural Gas Company, Energy Transfer Fuel, LP, DCP Guadalupe Pipeline, LP, Enterprise Texas Pipeline, Northern Natural Gas Company, Oasis Pipeline, LP, ONEOK Westex Transmission, LP, Public Service Company of New Mexico and Transwestern. Its major NGLs pipeline interconnects are with Chapparal, Louis Dreyfus and Chevron.

Natural Gas Supply Contracts

SUGS's gas supply contracts primarily include fee-based, percent-of-proceeds, conditioning fee and wellhead contracts, which as of December 31, 2007, comprised 50 percent, 39 percent, 9 percent and 2 percent by volume of its gas supply contracts, respectively. These gas supply contracts vary in length from month-to-month to a number of years, with many of the contracts having a term of three to five years.

Following is a summary description of the gas supply contracts utilized by SUGS:

- ***Fee-Based.*** Under fee-based arrangements, SUGS receives a fee or fees for one or more of the following services: gathering, compressing, treating or processing natural gas. The fee or fees are usually based on the volume or level of service provided to gather, compress, treat or process natural gas. While fee-based arrangements are generally not subject to commodity risk, certain operating conditions as well as provisions of these arrangements, including fuel recovery mechanisms, may subject SUGS to a limited amount of commodity risk.

- ***Percent-of-Proceeds, Percent-of-Value or Percent-of-Liquids.*** Under percent-of-proceeds arrangements, SUGS generally gathers and processes natural gas from producers for an agreed percentage of the proceeds from the sales of the resulting residue gas and NGLs. The percent-of-value and percent-of-liquids are variations on this arrangement. These types of arrangements expose SUGS to some commodity price risk as the costs and revenues from the contracts are directly correlated with the price of natural gas and NGLs.

- ***Conditioning Fee.*** Conditioning fee arrangements provide a guaranteed minimum margin or fee on gas that must be processed for liquid hydrocarbon extraction in order to meet the quality specifications of the transmission pipelines. In addition to the minimum margin or fee, SUGS keeps all or a large percentage of the value of the NGLs. The revenue earned is directly related to the processing value of the gas, however, SUGS is kept whole on a minimum value or fee in low processing spread environments.

- ***Keep-Whole and Wellhead.*** A keep-whole arrangement allows SUGS to keep 100 percent of the NGLs produced and requires the return of the processed natural gas, or value of the gas, to the producer or owner. Since some of the gas is used during processing, SUGS must compensate the producer or owner for the gas shrink entailed in processing by supplying additional gas or by paying an agreed value for the gas utilized. These arrangements have the highest commodity price exposure for SUGS because the costs are dependent on the price of natural gas and the revenues are based on the price of NGLs. As a result, SUGS benefits from these types of arrangements when the value of the NGLs is high relative to the cost of the natural gas and is disadvantaged when the cost of the natural gas is high relative to the value of NGLs. SUGS has the ability to eliminate its exposure to negative processing spreads by treating, dehydrating and blending the wellhead gas with leaner gas in order to meet downstream transmission pipeline specifications rather than processing the gas. In situations where the negative processing spread is eliminated, such contracts are referred to as wellhead contracts.

For information related to SUGS use of various derivative financial instruments to manage its commodity price risk and related operating cash flows, see *Item 8. Financial Statements and Supplementary Data, Note 11 – Derivative Instruments and Hedging Activities – Gathering and Processing Segment.*

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Regulation

SUGS' facilities are not currently regulated by FERC but are subject to oversight by various other governmental agencies, including matters of asset integrity, safety and environmental protection. The relevant agencies include the U.S. Environmental Protection Agency and its state counterparts, the Occupational Safety and Health Administration and the U.S. Department of Transportation's Office of Pipeline Safety and its state counterparts. The Company believes that its gathering and processing operations are in material compliance with applicable safety and environmental statutes and regulations.

Competition

SUGS competes with other midstream service providers and producer-owned midstream facilities in the Permian basin. The Company's direct competitors include Targa Resources Partners LP, DCP Midstream Partners, LP (formerly Duke Energy Field Services), Enterprise Texas Field Services, Anadarko Petroleum, Atlas Pipeline Partners, LP and Regency Gas Services. Industry factors that typically affect the Company's ability to compete in this segment are:

- contract fees charged,
- pressures maintained on the gathering systems,
- location of the gathering systems relative to competitors and producer drilling activity,
- efficiency and reliability of the operations, and
- delivery capabilities in each system and plant location.

Commodity prices for natural gas and NGLs also play a major role in drilling activity on or near the Company's gathering and processing systems. Generally, lower commodity prices will result in less producer drilling activity and conversely, higher commodity prices will result in increased producer drilling activity.

SUGS has responded to these industry conditions by positioning and configuring its gathering and processing facilities to offer a broad range of services to accommodate the types and quality of natural gas produced in the region, while many competing systems provide only a single level of service.

Distribution Segment

Services

The Company's Distribution segment is primarily engaged in the local distribution of natural gas in Missouri, through Missouri Gas Energy, and Massachusetts, through New England Gas Company. The utilities serve over 550,000 residential, commercial and industrial customers through local distribution systems consisting of 9,068 miles of mains, 6,096 miles of service lines and 45 miles of transmission lines. The utilities' natural gas rates and operations in Missouri and Massachusetts are regulated by the Missouri Public Service Commission (*MPSC*) and the Massachusetts Department of Public Utilities (*MDPU*), respectively.

The utilities operations have historically been sensitive to weather and are seasonal in nature, with a significant percentage of annual operating revenues and EBIT occurring in the traditional winter heating season in the first and fourth calendar quarters. However, the MPSC approved distribution rates effective April 3, 2007 for Missouri Gas Energy's residential customers (which comprise approximately 87 percent of its total customers and approximately 67 percent of its operating revenues) that eliminate the impact of weather and conservation for residential margin revenues and related earnings in Missouri.

For the years ended December 31, 2007, 2006 and 2005, the Distribution segment's *Operating revenues* were \$732.1 million, \$668.7 million and \$752.7 million, respectively; average customers served totaled 552,023, 551,604 and 548,514, respectively; and gas volumes sold or transported totaled 83,107 million cubic feet (*MMcf*), 77,890 MMcf and 84,112 MMcf, respectively. The Distribution segment has no single customer, or group of customers under common control, which accounted for ten percent or more of the Company's Distribution segment or the Company's total consolidated operating revenues for the years ended December 31, 2007, 2006 and 2005.

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For information about operating revenues, EBIT, assets and other financial information relating to the Distribution segment, see *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations – Business Segment Results – Distribution Segment* and *Item 8. Financial Statements and Supplementary Data, Note 21 – Reportable Segments.*

The Distribution segment customers served, gas volumes sold or transported and weather-related information for the years ended December 31, 2007, 2006 and 2005 are as follows:

	Years Ended December 31,		
	2007	**2006**	**2005**
Average number of customers:			
Residential	483,753	482,882	480,381
Commercial	66,631	67,120	66,608
Industrial	122	129	142
Total average customers served	550,506	550,131	547,131
Transportation customers	1,517	1,473	1,383
Total average gas sales and transportation customers	552,023	551,604	548,514
Gas sales (MMcf):			
Residential	37,916	34,946	39,160
Commercial	15,988	14,938	16,633
Industrial	504	517	525
Gas sales billed	54,408	50,401	56,318
Net change in unbilled gas sales	1,788	(1,025)	185
Total gas sales	56,196	49,376	56,503
Gas transported	26,911	26,340	27,609
Total gas sales and gas transported	83,107	75,716	84,112
Gas sales revenues ($ in thousands):			
Residential	$ 495,464	$ 472,926	$ 500,874
Commercial	186,987	189,837	201,122
Industrial	10,900	11,140	10,499
Gas revenues billed	693,351	673,903	712,495
Net change in unbilled gas sales revenues	9,491	(25,681)	19,561
Total gas sales revenues	702,842	648,222	732,056
Gas transportation revenues	12,669	12,253	12,885
Other revenues	16,598	8,246	7,758
Total operating revenues	$ 732,109	$ 668,721	$ 752,699
Weather:			
Massachusetts Utility Operations:			
Degree days (1)	5,371	4,901	5,801
Percent of 10-year measure (2)	86%	90%	106%
Percent of 30-year measure (2)	89%	85%	101%
Missouri Utility Operations:			
Degree days (1)	4,776	3,996	4,621
Percent of 10-year measure (2)	92%	77%	89%
Percent of 30-year measure (2)	92%	77%	89%

(1) "Degree days" are a measure of the coldness of the weather experienced. A degree day is equivalent to each degree that the daily mean
temperature for a day falls below 65 degrees Fahrenheit.

(2) Information with respect to weather conditions is provided by the National Oceanic and Atmospheric Administration. Percentages of 10-
and 30-year measures are computed based on the weighted average volumes of gas sales billed. The 10- and 30-year measures are used for consistent external reporting purposes. Measures of normal weather used by the Company's regulatory authorities to set rates

vary by jurisdiction. Periods used to measure normal weather for regulatory purposes range from 10 years to 30 years.

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Gas Supply

The cost and reliability of natural gas service are dependent upon the Company's ability to achieve favorable mixes of long-term and short-term gas supply agreements and fixed and variable transportation contracts. The Company has been acquiring its gas supplies directly since the mid-1980s when interstate pipeline systems opened their systems for transportation service. The Company sought to ensure reliable service to customers by developing the ability to dispatch and monitor gas volumes on a daily, hourly or real-time basis.

For the year ended December 31, 2007, the majority of the gas requirements for the utility operations of Missouri Gas Energy were delivered under short- and long-term transportation contracts through five major pipeline companies and more than 22 commodity suppliers. For this same period, the majority of the gas requirements for the Massachusetts utility operations of New England Gas Company were delivered under long-term contracts through five major pipeline companies and contracts with four commodity suppliers. Collectively, these contracts have various expiration dates ranging from 2009 through 2036. Missouri Gas Energy and New England Gas Company have firm supply commitments for all areas that are supplied with gas purchased under short- and long-term arrangements. Missouri Gas Energy and New England Gas Company hold contract rights to over 17 billion cubic feet (*Bcf*) and 1 Bcf of storage capacity, respectively, to assist in meeting peak demands.

Like the gas industry as a whole, Southern Union utilizes gas sales and/or transportation contracts with interruption provisions, by which large volume users purchase gas with the understanding that they may be forced to shut down or switch to alternate sources of energy at times when the gas is needed by higher priority customers for load management. In addition, during times of special supply problems, curtailments of deliveries to customers with firm contracts may be made in accordance with guidelines established by appropriate federal and state regulatory agencies.

Regulation and Rates

The Company's utilities are regulated as to rates, operations and other matters by the regulatory commissions of the states in which each operates. In Missouri, natural gas rates are established by the MPSC on a system-wide basis. In Massachusetts, natural gas rates for New England Gas Company are subject to the regulatory authority of the MDPU. For additional information concerning recent state and federal regulatory developments, see *Item 8. Financial Statements and Supplementary Data, Note 16 – Regulation and Rates.*

The Company holds non-exclusive franchises with varying expiration dates in all incorporated communities where it is necessary to carry on its business as it is now being conducted. Fall River, Massachusetts; Kansas City, Missouri; and St. Joseph, Missouri are the largest cities in which the Company's utility customers are located. The franchise in Kansas City, Missouri expires in 2010. The Company fully expects this franchise to be renewed prior to its expiration. The franchises in Fall River, Massachusetts and St. Joseph, Missouri are perpetual. Regulatory authorities establish gas service rates so as to permit utilities the opportunity to recover operating, administrative and financing costs, and the opportunity to earn a reasonable return on equity. Gas costs are billed to customers through purchased gas adjustment clauses, which permit the Company to adjust its sales price as the cost of purchased gas changes. This is important because the cost of natural gas accounts for a significant portion of the Company's total expenses. The appropriate regulatory authority must receive notice of such adjustments prior to billing implementation. The MPSC and MDPU allow such adjustments up to three and two times per year, respectively.

The Company supports any service rate changes that it proposes to its regulators using an historic test year of operating results adjusted to normal conditions and for any known and measurable revenue or expense changes. Because the regulatory process has certain inherent time delays, rate orders in these jurisdictions may not reflect the operating costs at the time new rates are put into effect.

Except for Missouri Gas Energy's residential customers, that are billed a fixed monthly charge for services provided, the Company's monthly customer bills contain a fixed service charge, a usage charge for service to deliver gas, and a charge for the amount of natural gas used. Although the monthly fixed charge provides an even revenue stream, the usage charge increases the Company's annual revenue and earnings in the traditional heating load months when usage of natural gas increases.

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In addition to public service commission regulation of its utility businesses, the Distribution segment is affected by other regulations, including pipeline safety regulations under the Natural Gas Pipeline Safety Act of 1968, the Pipeline Safety Improvement Act of 2002, safety regulations under the Occupational Safety and Health Act and various state and federal environmental statutes and regulations. The Company believes that its utility operations are in material compliance with applicable safety and environmental statutes and regulations.

The following table summarizes the rate proceedings applicable to the Distribution segment:

Utility Operations	Date of Last Rate Filing	Status (1)
Missouri	May 2006	MPSC rate order effective April 2007.
Massachusetts	June 2007	Settlement effective August 2007.

(1) For more information related to these rate filings, see *Item 8. Financial Statements and Supplementary Data, Note 16 – Regulation and Rates*.

Competition

As energy providers, Missouri Gas Energy and New England Gas Company have historically competed with alternative energy sources available to end-users in their service areas, particularly electricity, propane, fuel oil, coal, NGLs and other refined products. At present rates, the cost of electricity to residential and commercial customers in the Company's regulated utility service areas generally is higher than the effective cost of natural gas service. There can be no assurance, however, that future fluctuations in gas and electric costs will not reduce the cost advantage of natural gas service.

Competition between the use of fuel oils, natural gas and propane, particularly by industrial and electric generation customers, has increased due to the volatility of natural gas prices and increased marketing efforts from various energy companies. Competition among the use of fuel oils, natural gas and propane is generally greater in the Company's Massachusetts service area than in its Missouri service area. Nevertheless, this competition affects the nationwide market for natural gas. Additionally, the general economic conditions in the Company's regulated utility service areas continue to affect certain customers and market areas, thus impacting the results of the Company's operations. The Company's regulated utility operations are not currently in significant direct competition with any other distributors of natural gas to residential and small commercial customers within their service areas.

OTHER MATTERS

Environmental

The Company is subject to federal, state and local laws and regulations relating to the protection of the environment. These evolving laws and regulations may require expenditures over a long period of time to control environmental impacts. The Company has established procedures for the ongoing evaluation of its operations to identify potential environmental exposures. These procedures are designed to achieve compliance with such laws and regulations. For additional information concerning the impact of environmental regulation on the Company, see *Item 8. Financial Statements and Supplementary Data, Note 18 – Commitments and Contingencies.*

Insurance

The Company maintains insurance coverage provided under its policies similar to other comparable companies in the same lines of business. The insurance policies are subject to terms, conditions, limitations and exclusions that do not fully compensate the Company for all losses. Insurance deductibles range from $100,000 to $10 million for the various policies utilized by the Company.

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Employees

As of December 31, 2007, the Company had 2,337 employees, of whom 1,513 are paid on an hourly basis and 824 are paid on a salary basis. Unions represent approximately 50 percent of the 1,513 hourly paid employees. The table below sets forth the number of employees represented by unions for each division, as well as the expiration dates of the current contracts with the respective bargaining units.

Company	**Number of employees Represented by Unions**	**Expiration of Current Contract**
PEPL		
USW Local 348	215	May 27, 2009
Missouri Gas Energy		
Gas Workers 781	195	April 30, 2009
IBEW Local 53	98	April 30, 2009
USW Local 5-267	27	April 30, 2009
USW Local 12561, 14228	142	April 30, 2009
New England Gas Company		
UWUA Local 431	72	April 30, 2010

As of December 31, 2007, the number of persons employed by each segment was as follows: Transportation and Storage segment –1,121 persons; Gathering and Processing segment – 317 persons; Distribution segment – 792 persons; All Other subsidiary operations – 12 persons. In addition, the corporate employees of Southern Union totaled 95 persons.

The employees of Florida Gas are not employees of Southern Union or its segments and, therefore, were not considered in the employee statistics noted above. As of December 31, 2007, Florida Gas had 301 non-union employees.

The Company believes that its relations with its employees are good. From time to time, however, the Company may be subject to labor disputes. The Company did not experience any strikes or work stoppages during the years ended December 31, 2007, 2006 or 2005.

Available Information

Southern Union files annual, quarterly and special reports, proxy statements and other information with the Securities and Exchange Commission (*SEC*) as required. Any document that Southern Union files with the SEC may be read or copied at the SEC's public reference room at 100 F Street, N.E., Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 for information on the public reference room. Southern Union's SEC filings are also available at the SEC's website at http://www.sec.gov and through Southern Union's website at http://www.sug.com. The information on Southern Union's website is not incorporated by reference into and is not made a part of this report.

Southern Union, by and through the audit committee of its board of directors, has adopted a Code of Ethics and Business Conduct (*Code*) designed to reflect requirements of the Sarbanes-Oxley Act of 2002, New York Stock Exchange rules and other applicable laws, rules and regulations. The Code applies to all of the Company's directors, officers and employees. Any amendment to the Code will be posted promptly on Southern Union's website.

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Southern Union, by and through the corporate governance committee of its board of directors, also has adopted Corporate Governance Guidelines (*Guidelines*). The Guidelines set forth the responsibilities and standards under which the major board committees and management shall function. The Code of Ethics and Business Conduct (*Code*), the Guidelines and the charters of the audit, corporate governance, compensation and finance committees are posted on the Corporate Governance section of Southern Union's website under "Governance Documents" and are available free of charge by calling Southern Union at (713) 989-2000 or by writing to:

Southern Union Company
Attn: Corporate Secretary
5444 Westheimer Road
Houston, TX 77056

ITEM 1A. Risk Factors.

The risks and uncertainties described below are not the only ones faced by the Company. Additional risks and uncertainties that it is unaware of, or that it currently deems immaterial, may become important factors that affect it. If any of the following risks occur, the Company's business, financial condition, results of operations or cash flows could be materially and adversely affected.

RISKS THAT RELATE TO SOUTHERN UNION

Southern Union has substantial debt and depends on its ability to access the capital markets.

Southern Union has a significant amount of debt outstanding. As of December 31, 2007, consolidated debt on the Consolidated Balance Sheet totaled $3.5 billion outstanding, compared to total capitalization (long and short-term debt plus stockholders' equity) of $5.7 billion.

Some of the Company's debt obligations contain financial covenants concerning debt-to-capital ratios and interest coverage ratios. The Company's failure to comply with any of these covenants could result in an event of default which, if not cured or waived, could result in the acceleration of outstanding debt obligations or render the Company unable to borrow under certain credit agreements. Any such acceleration or inability to borrow could cause a material adverse change in the Company's financial condition.

The Company relies on access to both short-term and long-term credit as a significant source of liquidity for capital requirements not satisfied by the cash flow from its operations. Any worsening of the Company's financial condition or a material decrease in its common stock price could hamper its ability to access the capital markets. External events could also increase the Company's cost of borrowing or adversely affect its ability to access the capital markets.

Further, because of the need for certain state regulatory approvals in order to incur debt and issue capital stock, the Company may not be able to access the capital markets on a timely basis. Restrictions on the Company's ability to access capital markets could affect its ability to execute its business plan or limit its ability to pursue improvements or acquisitions on which it may otherwise rely for future growth.

The Company plans to refinance its $425 million of debt maturing in August 2008 with new capital market debt or bank financings. Alternatively, should the Company not be successful in its refinancing efforts, the Company may choose to retire such debt upon maturity by utilizing some combination of cash flows from operations, draw downs under existing credit facilities, and altering the timing of controllable expenditures, among other things. The Company believes, based on its investment grade credit ratings and general financial condition, successful historical access to capital and debt markets, current economic and capital market conditions and market expectations regarding the Company's future earnings and cash flows, that it will be able to refinance and/or retire these obligations under acceptable terms prior to their maturity. There can be no assurance, however, that the Company will be able to achieve acceptable refinancing terms in any negotiation of new capital market debt or bank financings. Moreover, there can be no assurance the Company will be successful in its implementation of these refinancing and/or retirement plans and the Company's inability to do so would cause a material adverse effect on the Company's financial condition and liquidity.

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Credit ratings downgrades could increase the Company's financing costs and limit its ability to access the capital markets.

As of December 31, 2007, both Southern Union's and Panhandle's debt is rated Baa3 by Moody's Investor Services, Inc., BBB- by Standard & Poor's and BBB by Fitch Ratings. If the Company's credit ratings are downgraded below investment grade or if there are times when it is placed on "credit watch," both borrowing costs and the costs of maintaining certain contractual relationships could increase. Lower credit ratings could also adversely affect the Distribution segment's relationships with state regulators, who may be unwilling to allow the Company to pass along increased debt service costs to natural gas customers.

The Company's growth strategy entails risk for investors.

The Company intends to actively pursue acquisitions in the energy industry to complement and diversify its existing businesses. As part of its growth strategy, Southern Union may:

- examine and potentially acquire regulated or unregulated businesses, including transportation and storage assets and gathering and processing businesses within the natural gas industry;
- enter into joint venture agreements and/or other transactions with other industry participants or financial investors;
- selectively divest parts of its business, including parts of its core operations; and
- continue expanding its existing operations.

The Company's ability to acquire new businesses will depend upon the extent to which opportunities become available, as well as, among other things:

- its success in bidding for the opportunities;
- its ability to assess the risks of the opportunities;
- its ability to obtain regulatory approvals on favorable terms; and
- its access to financing on acceptable terms.

Once acquired, the Company's ability to integrate a new business into its existing operations successfully will depend on the adequacy of implementation plans, including the ability to identify and retain employees to manage the acquired business, and the ability to achieve desired operating efficiencies. The successful integration of any businesses acquired in the future may entail numerous risks, including, among others:

- the risk of diverting management's attention from day-to-day operations;
- the risk that the acquired businesses will require substantial capital and financial investments;
- the risk that the investments will fail to perform in accordance with expectations; and
- the risk of substantial difficulties in the transition and integration process.

These factors could have a material adverse effect on the Company's business, financial condition, results of operations and cash flows, particularly in the case of a larger acquisition or multiple acquisitions in a short period of time.

Additionally, if the Company expands its existing operations, the success of any such expansion is subject to substantial risk and may expose the Company to significant costs. The Company cannot assure that its development or construction efforts will be successful.

The consideration paid in connection with an investment or acquisition also affects the Company's financial results. To the extent it issues shares of capital stock or other rights to purchase capital stock, including options or other rights, existing stockholders may be diluted and earnings per share may decrease. In addition, acquisitions or expansions may result in the incurrence of additional debt.

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The Company depends on distributions from its subsidiaries and joint ventures to meet its needs.

The Company is dependent on the earnings and cash flows of, and dividends, loans, advances or other distributions from, its subsidiaries and joint ventures (including Citrus) to generate the funds necessary to meet its obligations. The availability of distributions from such entities is subject to their earnings and capital requirements, the satisfaction of various covenants and conditions contained in financing documents by which they are bound or in their organizational documents, and in the case of the regulated subsidiaries, regulatory restrictions that limit their ability to distribute profits to Southern Union.

The Company owns 50 percent of Citrus, the holding company for Florida Gas. As such, the Company cannot control or guarantee the receipt of distributions from Florida Gas through Citrus.

The Company is subject to operating risks.

The Company's operations are subject to all operating hazards and risks incident to handling, storing, transporting and providing customers with natural gas or NGLs, including explosions, pollution, release of toxic substances, fires and other hazards, each of which could result in damage to or destruction of its facilities or damage to persons and property. If any of these events were to occur, the Company could suffer substantial losses. Moreover, as a result, the Company has been, and likely will be, a defendant in legal proceedings and litigation arising in the ordinary course of business. Although the Company maintains insurance coverage, such coverage may be inadequate to protect the Company from all expenses related to these risks.

The Company is subject to extensive federal, state and local laws and regulations regulating the environmental aspects of its business that may increase its costs of operation, expose it to environmental liabilities and require it to make material unbudgeted expenditures.

The Company is subject to extensive federal, state and local laws and regulations regulating the environmental aspects of its business (including air emissions), which are complex and have tended to become increasingly strict over time. These laws and regulations have necessitated, and in the future may necessitate, increased capital expenditures and operating costs. In addition, certain environmental laws may result in liability without regard to fault concerning contamination at a broad range of properties, including those currently or formerly owned, leased or operated properties and properties where the Company disposed of, or arranged for the disposal of, waste.

The Company is currently monitoring or remediating contamination at a number of its facilities and at third party waste disposal sites pursuant to environmental laws and regulations and indemnification agreements. The Company cannot predict with certainty the sites for which it may be responsible, the amount of resulting cleanup obligations that may be imposed on it or the amount and timing of future expenditures related to environmental remediation because of the difficulty of estimating cleanup costs and the uncertainty of payment by other potentially responsible parties.

Costs and obligations also can arise from claims for toxic torts and natural resource damages or from releases of hazardous materials on other properties as a result of ongoing operations or disposal of waste. Compliance with amended, new or more stringently enforced existing environmental requirements, or the future discovery of contamination, may require material unbudgeted expenditures. These costs or expenditures could have a material adverse effect on the Company's business, financial condition, results of operations or cash flows, particularly if such costs or expenditures are not fully recoverable from insurance or through the rates charged to customers or if they exceed any amounts that have been reserved.

Terrorist attacks, such as the attacks that occurred on September 11, 2001, have resulted in increased costs, and the consequences of the War on Terror and the Iraq conflict may adversely impact the Company's results of operations.

The impact that terrorist attacks, such as the attacks of September 11, 2001, may have on the energy industry in general, and on the Company in particular, is not known at this time. Uncertainty surrounding military activity may affect the Company's operations in unpredictable ways, including disruptions of fuel supplies and markets and the possibility that infrastructure facilities, including pipelines, LNG facilities, gathering facilities and processing plants,

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could be direct targets of, or indirect casualties of, an act of terror or a retaliatory strike. The Company may have to incur significant additional costs in the future to safeguard its physical assets.

Federal, state and local jurisdictions may challenge the Company's tax return positions

The positions taken by the Company in its tax return filings require significant judgment, use of estimates, and the interpretation and application of complex tax laws. Significant judgment is also required in assessing the timing and amounts of deductible and taxable items. Despite management's belief that the Company's tax return positions are fully supportable, certain positions may be successfully challenged by federal, state and local jurisdictions.

The success of the pipeline and gathering and processing businesses depends, in part, on factors beyond the Company's control.

Third parties own most of the natural gas transported and stored through the pipeline systems operated by Panhandle and Florida Gas. Additionally, third parties produce all the natural gas or NGLs gathered and processed by SUGS. As a result, the volume of natural gas transported, stored, gathered or processed depends on the actions of those third parties and is beyond the Company's control. Further, other factors beyond the Company's control may unfavorably impact its ability to maintain or increase current transmission, storage, gathering or processing rates, to renegotiate existing contracts as they expire or to remarket unsubscribed capacity.

The success of the pipeline and gathering and processing businesses depends on the continued development of additional natural gas reserves in the vicinity of their facilities and their ability to access additional reserves to offset the natural decline from existing wells connected to their systems.

The amount of revenue generated by Panhandle and Florida Gas ultimately depends upon their access to reserves of available natural gas. Additionally, the amount of revenue generated by SUGS depends substantially upon the volume of natural gas or NGLs gathered and processed. As the reserves available through the supply basins connected to these systems naturally decline, a decrease in development or production activity could cause a decrease in the volume of natural gas available for transmission, gathering or processing. Investments by third parties in the development of new natural gas reserves connected to the Company's facilities depend on many factors beyond the Company's control.

The pipeline and gathering and processing business revenues are generated under contracts that must be renegotiated periodically.

The revenues of Panhandle, Florida Gas and SUGS are generated under contracts that expire periodically. Although the Company will actively pursue the renegotiation, extension and/or replacement of all of its contracts, it cannot assure that it will be able to extend or replace these contracts when they expire or that the terms of any renegotiated contracts will be as favorable as the existing contracts. If the Company is unable to renew, extend or replace these contracts, or if the Company renews them on less favorable terms, it may suffer a material reduction in revenues and earnings.

The expansion of the Company's pipeline and gathering and processing systems by constructing new facilities subjects the Company to construction and other risks that may adversely affect the financial results of the pipeline and gathering and processing businesses.

During 2007, the domestic energy industry experienced an unprecedented level of expansion activity, including new natural gas and LNG pipelines and compression infrastructure projects. This level of activity is expected to continue for a period of three to four years. As a result, requirements for material, equipment and construction resources are straining supply and causing significant industry-wide cost increases. While the Company's project cost estimates include provisions for cost escalation, future costs are uncertain. Further, the Company's construction productivity was adversely affected in 2007 by contractor employee turnover and shortages of experienced contractor staff, as well as other factors beyond the Company's control, such as weather conditions. These factors may continue to affect ultimate cost and timing of the Company's expansion projects through the current construction boom-cycle.

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RISKS THAT RELATE TO THE COMPANY'S TRANSPORTATION AND STORAGE BUSINESS

The Company's transportation and storage business is highly regulated.

The Company's transportation and storage business is subject to regulation by federal, state and local regulatory authorities. FERC, the U.S. Department of Transportation and various state and local regulatory agencies regulate the interstate pipeline business. In particular, FERC regulates services provided and rates charged by Panhandle and Florida Gas. In addition, the U.S. Coast Guard has oversight over certain issues related to the importation of LNG.

The Company's rates and operations are subject to regulation by federal regulators as well as the actions of Congress and state legislatures and, in some respects, state regulators. The Company cannot predict or control what effect future actions of regulatory agencies may have on its business or its access to the capital markets. Furthermore, the nature and degree of regulation of natural gas companies has changed significantly during the past 25 years and there is no assurance that further substantial changes will not occur or that existing policies and rules will not be applied in a new or different manner.

Should new regulatory requirements regarding the security of its pipeline system or new accounting requirements for certain entities be imposed, the Company could be subject to additional costs that could adversely affect its business, financial condition or results of operations if these costs are deemed unrecoverable in rates.

The pipeline businesses are subject to competition.

The interstate pipeline businesses of Panhandle and Florida Gas compete with those of other interstate and intrastate pipeline companies in the transportation and storage of natural gas. The principal elements of competition among pipelines are rates, terms of service and the flexibility and reliability of service. Natural gas competes with other forms of energy available to the Company's customers and end-users, including electricity, coal and fuel oils. The primary competitive factor is price. Changes in the availability or price of natural gas and other forms of energy, the level of business activity, conservation, legislation and governmental regulations, the capability to convert to alternate fuels and other factors, including weather and natural gas storage levels, affect the demand for natural gas in the areas served by Panhandle and Florida Gas.

Substantial risks are involved in operating a natural gas pipeline system.

Numerous operational risks are associated with the operation of a complex pipeline system. These include adverse weather conditions, accidents, the breakdown or failure of equipment or processes, the performance of pipeline facilities below expected levels of capacity and efficiency, the collision of equipment with pipeline facilities (such as may occur if a third party were to perform excavation or construction work near the facilities) and other catastrophic events beyond the Company's control. In particular, the Company's pipeline system, especially those portions that are located offshore, may be subject to adverse weather conditions including hurricanes, earthquakes, tornadoes, extreme temperatures and other natural phenomena, making it more difficult for the Company to realize the historic rates of return associated with these assets and operations. It is also possible that infrastructure facilities could be direct targets or indirect casualties of an act of terror. A casualty occurrence might result in injury or loss of life, extensive property damage or environmental damage. Insurance proceeds may be inadequate to cover all liabilities or expenses incurred or revenues lost.

Fluctuations in energy commodity prices could adversely affect the pipeline businesses.

If natural gas prices in the supply basins connected to the pipeline systems of Panhandle and Florida Gas are higher than prices in other natural gas producing regions, especially Canada, the volume of gas transported by the Company may be negatively impacted.

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The pipeline businesses are dependent on a small number of customers for a significant percentage of their sales.

Panhandle's top three customers accounted for 48 percent of its 2007 revenue. Florida Gas' top two customers accounted for 56 percent of its 2007 revenue. The loss of any one or more of these customers could have a material adverse effect on the Company's business, financial condition, results of operations or cash flows.

The Company is exposed to the credit risk of its transportation and storage customers in the ordinary course of business.

Transportation service contracts obligate customers to pay charges for reservation of capacity, or reservation charges, regardless of whether they transport natural gas on the pipeline system. As a result, the Company's profitability will depend upon the continued financial performance and creditworthiness of its customers rather than just upon the amount of capacity provided under service contracts.

Generally, customers are rated investment grade or, as permitted by the Company's tariff, are required to make pre-payments or deposits, or to provide collateral, if their creditworthiness does not meet certain criteria. Nevertheless, the Company cannot predict to what extent future declines in customers' creditworthiness may negatively impact its business.

RISKS THAT RELATE TO THE COMPANY'S NATURAL GAS GATHERING AND PROCESSING BUSINESS

The Company's natural gas gathering and processing business is unregulated.

Unlike the Company's returns on its regulated transportation and distribution businesses, the natural gas and NGLs gathering and processing operations conducted at SUGS are not regulated and may potentially have a higher level of risk than the Company's regulated operations.

Although SUGS operates in an unregulated market, the business is subject to certain regulatory risks, most notably environmental and safety regulations. Moreover, the Company cannot predict when additional legislation or regulation might affect the gathering and processing industry, nor the impact of any such changes on the Company's business, financial position, results of operations or cash flows.

The Company's natural gas gathering and processing business is subject to competition.

The natural gas gathering and processing industry is expected to remain highly competitive. Most customers of SUGS have access to more than one gathering and/or processing system. The Company's ability to compete depends on a number of factors, including the infrastructure and contracting strategy of competitors in the Company's gathering region; the efficiency, quality and reliability of the Company's system; and the Company's ability to maintain a reliable low-cost pipeline operating system.

In addition to SUGS' current competitive position in the natural gas gathering and processing industry, its business is subject to pricing risks associated with changes in the supply of, and the demand for, natural gas and NGL byproducts. If natural gas or NGL prices in the supply basins connected to the Company's gathering system are comparatively higher than prices in other natural gas producing regions, the volume of gas that SUGS chooses to process may be reduced to maximize returns to the Company. Similarly, since the demand for natural gas or NGLs is primarily a function of commodity prices (including prices for alternative energy sources), customer usage rates, weather, economic conditions and service costs, the volume processed by SUGS may be reduced based on these market conditions on a daily basis after analysis by the Company.

The Company's profit margin in the natural gas gathering and processing business is highly dependent on energy commodity prices.

SUGS' gross margin is largely derived from (a) percentage of proceeds arrangements based on the volume of gas gathered and/or NGLs processed through its facilities or (b) specified fee arrangements for a range of services provided. Under percent-of-proceeds arrangements, SUGS generally gathers and processes natural gas from producers for an agreed percentage of the proceeds from the sales of the resulting residue gas and

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NGLs. The percent-of-proceeds arrangements, in particular, expose SUGS' revenues and cash flows to risks associated with the fluctuation of the price of natural gas, NGLs, crude oil and their relationship to each other.

The markets and prices for natural gas and NGLs depend upon factors beyond our control. These factors include demand for these commodities, which fluctuate with changes in market and economic conditions and other factors, including:

- the impact of seasonality and weather;
- general economic conditions;
- the level of domestic crude oil and natural gas production and consumption;
- the availability of imported natural gas, NGLs and crude oil;
- actions taken by foreign oil and gas producing nations;
- the availability of local, intrastate and interstate transportation systems;
- the availability of natural gas liquids transportation and fractionation capacity;
- the availability and marketing of competitive fuels;
- the impact of energy conservation efforts; and
- the extent of governmental regulation and taxation.

The Company employs various derivative financial instruments to manage commodity price risk. The Company uses a combination of fixed price physical forward contracts, exchange-traded futures and options and fixed for floating index and basis swaps to manage commodity price risk. These derivative financial instruments allow the Company to preserve value and protect margins because changes in the value of the derivative financial instruments are effective in offsetting changes in the physical market and reducing basis risk. However, these financial derivative instrument contracts do not entirely eliminate pricing risks and, to the extent certain elements of these financial derivative instruments are speculative in nature, may expose the Company to losses or unprotected margins and value diminution. Moreover, the Company is subject to other risks including un-hedged commodity price changes, market supply shortages and customer defaults. For information related to derivative financial instruments, see *Item 8. Financial Statements and Supplementary Data – Note 11 Derivative Instruments and Hedging Activities – Gathering and Processing Segment*.

Operational risks are involved in operating a natural gas gathering and processing business.

Numerous operational risks are associated with the operation of a natural gas gathering and processing business. These include adverse weather conditions, accidents, the breakdown or failure of equipment or processes, the performance of processing facilities below expected levels of capacity or efficiency, the collision of equipment with facilities and catastrophic events such as explosions, fires, earthquakes, floods, landslides, tornadoes, lightning or other similar events beyond the Company's control. It is also possible that infrastructure facilities could be direct targets or indirect casualties of an act of terror. A casualty occurrence might result in injury or loss of life, extensive property damage or environmental damage. Insurance proceeds may be inadequate to cover all liabilities or expenses incurred or revenues lost.

The Company's natural gas gathering and processing business accepts some credit risk in dealing with customers.

SUGS derives its revenues from customers engaged primarily in the natural gas and utilities industries and extends payment credit to these customers. SUGS' accounts receivable primarily consist of mid- to large-size domestic customers with credit ratings of investment grade or better. Moreover, SUGS maintains trading relationships with counterparties that include reputable U.S. broker-dealers and other financial institutions and evaluates the ability of each counterparty to perform under the terms of the derivative agreements. Nevertheless, the Company cannot predict to what extent future declines in customers' creditworthiness may negatively impact its business.

The inability to continue to access independently owned and publicly owned lands could adversely affect the Company's ability to operate and/or expand its natural gas gathering and processing business.

SUGS' ability to operate within its operating region will depend on its success in maintaining existing rights-of-way and obtaining new rights-of-way. Securing additional rights-of-way is also critical to SUGS' ability to pursue expansion projects. SUGS cannot assure that it will be able to acquire new rights-of-way or maintain access to existing rights-of-way upon the expiration of the current grants. The Company's financial position could be adversely affected if the costs of new or extended rights-of-way grants exceed the margin within a gathering region.

RISKS THAT RELATE TO THE COMPANY'S DISTRIBUTION BUSINESS

The distribution business is highly regulated and the Company's revenues, operating results and financial condition may fluctuate with the distribution business' ability to achieve timely and effective rate relief from state regulators.

The Company's distribution business is subject to regulation by the MPSC and the MDPU. These authorities regulate many aspects of the

Company's distribution operations, including construction and maintenance of facilities, operations, safety, the rates that can be charged to customers and the maximum rates of return that the Company is allowed to realize. The ability to obtain rate increases and rate supplements to maintain the current rate of return depends upon regulatory discretion.

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The distribution business is influenced by fluctuations in costs, including operating costs such as insurance, postretirement and other benefit costs, wages, changes in the provision for the allowance for doubtful accounts associated with volatile natural gas costs and other operating costs. The profitability of regulated operations depends on the business' ability to pass through to its customers costs related to providing them service. To the extent that such operating costs increase in an amount greater than that for which rate recovery is allowed, this differential could impact operating results until the business files for and is allowed an increase in rates. The lag between an increase in costs and the rate relief obtained from the regulators can have a direct negative impact on operating results. As with any request for an increase in rates in a regulatory filing, once granted, the rate increase may not be adequate. In addition, regulators may prevent the business from passing along some costs in the form of higher rates.

The distribution business' operating results and liquidity needs are seasonal in nature and may fluctuate based on weather conditions and natural gas prices.

The gas distribution business is a seasonal business and is subject to weather conditions. The utilities' operations have historically been sensitive to weather and are seasonal in nature, with a significant percentage of annual operating revenues and EBIT occurring in the traditional winter heating season in the first and fourth calendar quarters. However, the MPSC approved distribution rates effective April 3, 2007 for Missouri Gas Energy's residential customers (which comprise approximately 87 percent of its total customers and approximately 67 percent of its operating revenues) that eliminate the impact of weather and conservation for residential margin revenues and related earnings in Missouri.

The business is also subject to seasonal and other variations in working capital due to changes in natural gas prices and the fact that customers pay for the natural gas delivered to them after they use it, whereas the business is required to pay for the natural gas before delivery. As a result, fluctuations in weather between years may have a significant effect on results of operations and cash flows. In years with warm winters, revenues may be adversely affected.

Operational risks are involved in operating a natural gas distribution business.

Numerous risks are associated with the operations of a natural gas distribution business. These include adverse weather conditions, accidents, the breakdown or failure of equipment or processes, the performance of suppliers' processing facilities below expected levels of capacity or efficiency, the collision of equipment with facilities and catastrophic events such as explosions, fires, earthquakes, floods, landslides, tornadoes, lightning or other similar events beyond the Company's control. It is also possible that infrastructure facilities could be direct targets or indirect casualties of an act of terror. A casualty occurrence might result in injury or loss of life, extensive property damage or environmental damage. Insurance proceeds may be inadequate to cover all liabilities or expenses incurred or revenues lost.

CAUTIONARY FACTORS THAT MAY AFFECT FUTURE RESULTS

The disclosure and analysis in this Form 10-K contains forward-looking statements that set forth anticipated results based on management's plans and assumptions. From time to time, Southern Union also provides forward-looking statements in other materials it releases to the public as well as oral forward-looking statements. Such statements give the Company's current expectations or forecasts of future events; they do not relate strictly to historical or current facts. Southern Union has tried, wherever possible, to identify such statements by using words such as "anticipate," "estimate," "expect," "project," "intend," "plan," "believe," "will" and similar expressions in connection with any discussion of future operating or financial performance. In particular, these include statements relating to future actions, future performance or results of current and anticipated services, expenses, interest rates, the outcome of contingencies, such as legal proceedings, and financial results.

Southern Union cannot guarantee that any forward-looking statement will be realized, although management believes that the Company has been prudent in its plans and assumptions. Achievement of future results is subject to risks, uncertainties and potentially inaccurate assumptions. If known or unknown risks or uncertainties should materialize, or if underlying assumptions should prove inaccurate, actual results could differ materially from past results and those anticipated, estimated or projected. Readers should bear this in mind as they consider forward-looking statements.

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Southern Union undertakes no obligation to update publicly forward-looking statements, whether as a result of new information, future events or otherwise. Readers are advised, however, to consult any further disclosures the Company makes on related subjects in its Form 10-K, Form 10-Q and Form 8-K reports to the SEC. Also note that Southern Union provides the following cautionary discussion of risks, uncertainties and possibly inaccurate assumptions relevant to its businesses. These are factors that, individually or in the aggregate, management believes could cause the Company's actual results to differ materially from expected and historical results. Southern Union notes these factors for investors as permitted by the Private Securities Litigation Reform Act of 1995. Readers should understand that it is not possible to predict or identify all such factors. Consequently, readers should not consider the following to be a complete discussion of all potential risks or uncertainties.

Factors that could cause actual results to differ materially from those expressed in the Company's forward-looking statements include, but are not limited to, the following:

- changes in demand for natural gas by the Company's customers, the composition of the Company's customer base and in the sources of natural gas available to the Company;
- the effects of inflation and the timing and extent of changes in the prices and overall demand for and availability of natural gas or natural gas liquid products as well as electricity, oil, coal and other bulk materials and chemicals;
- adverse weather conditions, such as warmer than normal weather in the Company's service territories, and the operational impact of natural disasters;
- changes in laws or regulations, third-party relations and approvals, decisions of courts, regulators and governmental bodies affecting or involving Southern Union, including deregulation initiatives and the impact of rate and tariff proceedings before FERC and various state regulatory commissions;
- the speed and degree to which additional competition is introduced to Southern Union's business and the resulting effect on revenues;
- the outcome of pending and future litigation;
- the Company's ability to comply with or to challenge successfully existing or new environmental regulations;
- unanticipated environmental liabilities;
- The Company's increased exposure to highly competitive commodity businesses through its Gathering and Processing segment;
- the Company's ability to acquire new businesses and assets and integrate those operations into its existing operations, as well as its ability to expand its existing businesses and facilities;
- the Company's ability to control costs successfully and achieve operating efficiencies, including the purchase and implementation of new technologies for achieving such efficiencies;
- the impact of factors affecting operations such as maintenance or repairs, environmental incidents, gas pipeline system constraints and relations with labor unions representing bargaining-unit employees;
- exposure to customer concentration with a significant portion of revenues realized from a relatively small number of customers and any credit risks associated with the financial position of those customers;
- changes in the ratings of the debt securities of Southern Union or any of its subsidiaries;
- changes in interest rates and other general capital markets conditions, and in the Company's ability to continue to access the capital markets;
- acts of nature, sabotage, terrorism or other acts causing damage greater than the Company's insurance coverage limits;
- market risks beyond the Company's control affecting its risk management activities including market liquidity, commodity price volatility and counterparty creditworthiness; and
- other risks and unforeseen events.

ITEM 1B. Unresolved Staff Comments.

N/A

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ITEM 2. Properties.

TRANSPORTATION AND STORAGE

See *Item 1. Business – Business Segments – Transportation and Storage Segment* for information concerning the general location and characteristics of the important physical properties and assets of the Transportation and Storage segment.

GATHERING AND PROCESSING

See *Item 1. Business – Business Segments – Gathering and Processing Segment* for information concerning the general location and characteristics of the important physical properties and assets of the Gathering and Processing segment.

DISTRIBUTION

See *Item 1. Business – Business Segments – Distribution Segment* for information concerning the general location and characteristics of the important physical properties and assets of the Distribution segment.

OTHER

The Company's other businesses primarily consist of PEI Power Corporation, a wholly-owned subsidiary of the Company, which has ownership interests in two electric power plants that share a site in Archbald, Pennsylvania. PEI Power Corporation wholly owns one plant, a 25 megawatt electric cogeneration facility fueled by a combination of natural gas and methane, and owns 49.9 percent of the second plant, a 45 megawatt natural gas-fired electric generation facility, through a joint venture with Cayuga Energy.

ITEM 3. Legal Proceedings.

Southern Union is a party to or has property subject to litigation and other proceedings, including matters arising under provisions relating to the protection of the environment, as described in *Item 8. Financial Statements and Supplementary Data, Note 18 – Commitments and Contingencies*. Also see *Item 1A. Risk Factors – Cautionary Factors That May Affect Future Results.*

ITEM 4. Submission of Matters to a Vote of Security Holders.

N/A

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PART II

ITEM 5. Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.

MARKET INFORMATION

Southern Union's common stock is traded on the New York Stock Exchange under the symbol "SUG." The high and low sales prices for shares of Southern Union common stock and the cash dividends per share declared in each quarter since January 1, 2006 are set forth below:

	Dollars per share		
	High	**Low**	**Dividends**
(Quarter Ended)			
December 31, 2007	$ 33.01	$ 28.46	$ 0.15
September 30, 2007	35.05	27.20	0.10
June 30, 2007	35.50	30.35	0.10
March 31, 2007	30.50	26.81	0.10
(Quarter Ended)			
December 31, 2006	$ 29.76	$ 26.19	$ 0.10
September 30, 2006	27.75	25.83	0.10
June 30, 2006	27.22	22.76	0.10
March 31, 2006	25.55	22.90	0.10

Provisions in certain of Southern Union's long-term debt and bank credit facilities limit the issuance of dividends on capital stock. Under the most restrictive provisions in effect, Southern Union may not declare or issue any dividends on its common stock or acquire or retire any of Southern Union's common stock, unless no event of default exists and the Company meets certain financial ratio requirements, which presently are met. Southern Union's ability to pay cash dividends may be limited by debt restrictions at Panhandle and Citrus that could limit Southern Union's access to funds from Panhandle and Citrus for debt service or dividends. See *Item 8. Financial Statements and Supplementary Data, Note 13 – Debt Obligations*.

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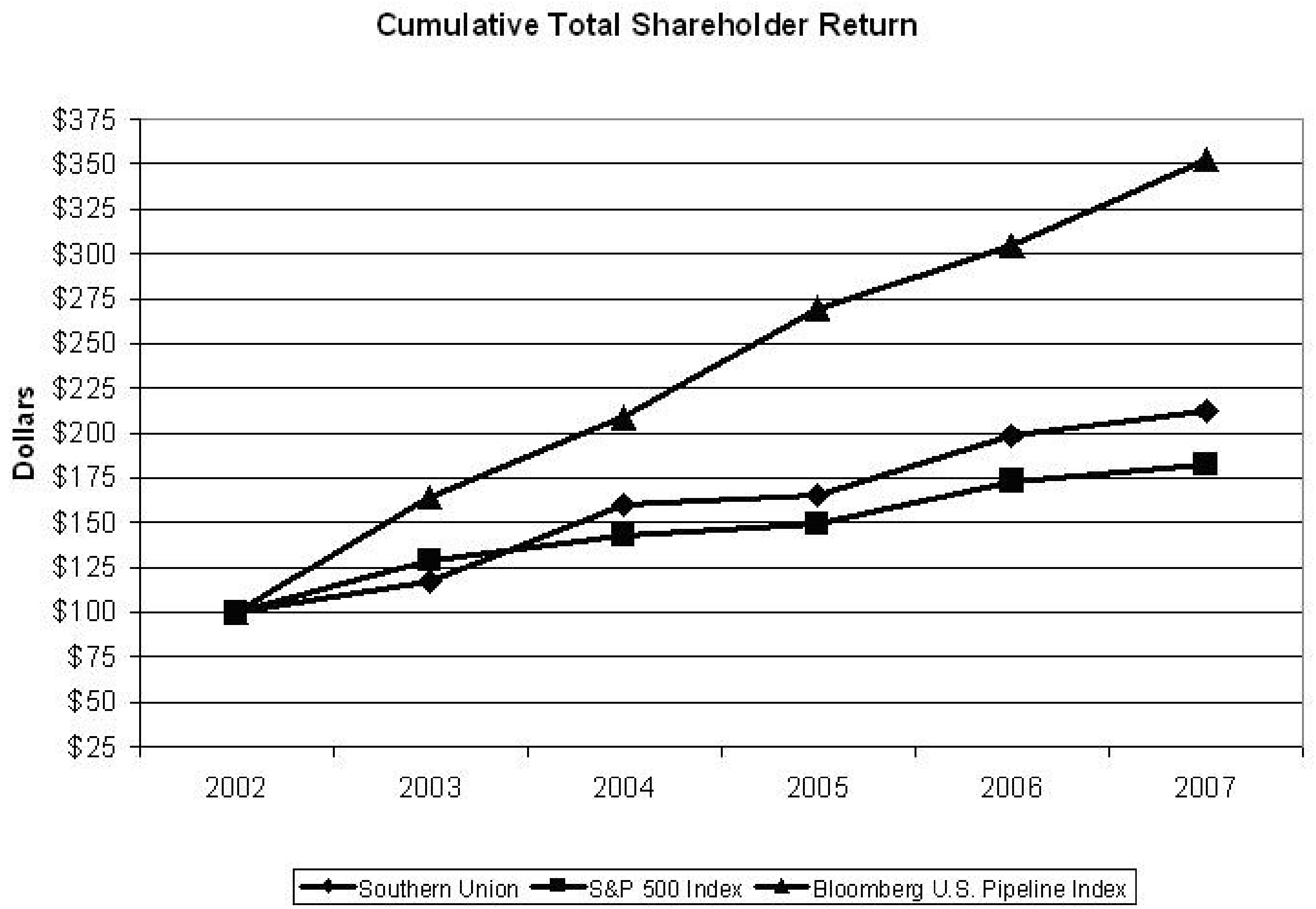
COMMON STOCK PERFORMANCE GRAPH

The following performance graph compares the performance of Southern Union's common stock to the Standard & Poor's 500 Stock Index (*S&P 500 Index*) and the Bloomberg U.S. Pipeline Index. The comparison assumes $100 was invested on December 31, 2002 in Southern Union common stock, the S&P 500 Index and in the Bloomberg U.S. Pipeline Index. Each case assumes reinvestment of dividends.



	2002	2003	2004	2005	2006	2007
Southern Union	100	117	160	166	199	212
S&P 500 Index	100	129	143	150	173	183
Bloomberg U.S. Pipeline Index	100	164	209	270	305	353

The following companies are included in the Bloomberg U.S. Pipeline Index used in the graph: El Paso Corp., Enbridge, Inc., Equitable Resources, Inc., ONEOK, Inc., Questar Corp., Spectra Energy Corp., TransCanada Corp., and Williams Cos, Inc.

HOLDERS

As of February 22, 2008, there were 5,996 holders of record of Southern Union's common stock, and 123,772,513 shares of Southern Union's common stock were issued and outstanding. The holders of record do not include persons whose shares are held of record by a bank, brokerage house or clearing agency, but do include any such bank, brokerage house or clearing agency that is a holder of record.

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EQUITY COMPENSATION PLANS

Equity compensation plans approved by stockholders include the Southern Union Company Second Amended and Restated 2003 Stock and Incentive Plan and the 1992 Long-Term Stock Incentive Plan (*1992 Plan*). While Southern Union options are still outstanding under the 1992 Plan, the 1992 Plan expired on July 1, 2002 and no shares are available for future grant thereunder. Under both plans, stock options are issued having an exercise price equal to the fair market value of the common stock on the date of grant and typically vest ratably over three, four or five years.

The following table sets forth the number of outstanding options and stock appreciation rights (*SARs*), the weighted-average exercise price of outstanding options and the number of shares remaining available for issuance as of December 31, 2007:

Plan Category	Number of Securities to Be issued Upon Exercise of Outstanding Options/SARs		Weighted-Average Exercise Price of Outstanding Options/SARs	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans
Plans approved by stockholders	2,076,836	(1)	$22.87	6,304,479

(1) Excludes 201,170 shares of restricted stock that were outstanding at December 31, 2007.

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ITEM 6. SELECTED FINANCIAL DATA.

	For the years ended December 31,			For the six months ended December 31,	For the years ended June 30,	
	2007	2006 (1)	2005	2004 (2)	2004	2003 (3)
	(In thousands of dollars, except per share amounts)					
Total operating revenues	$ 2,616,665	$ 2,340,144	$ 1,266,882	$ 517,849	$ 1,149,268	$ 596,330
Earnings from unconsolidated investments	100,914	141,370	70,742	4,745	200	422
Net earnings (loss):						
Continuing operations (4)	211,346	199,718	135,731	(1,635)	51,729	(12,425)
Discontinued operations (5)	-	(152,952)	(132,413)	7,723	49,610	88,614
Available for common stockholders	211,346	46,766	3,318	6,088	101,339	76,189
Net earnings (loss) per diluted common share (6):						
Continuing operations	1.75	1.70	1.20	(0.02)	0.63	(0.19)
Discontinued operations	-	(1.30)	(1.17)	0.09	0.61	1.36
Available for common stockholders	1.75	0.40	0.03	0.07	1.24	1.17
Total assets	7,397,913	6,782,790	5,836,819	5,568,289	4,572,458	4,590,938
Stockholders' equity	2,205,806	2,050,408	1,854,069	1,497,557	1,261,991	920,418
Current portion of long-term debt and capital lease obligation	434,680	461,011	126,648	89,650	99,997	734,752
Long-term debt and capital lease obligation, excluding current portion	2,960,326	2,689,656	2,049,141	2,070,353	2,154,615	1,611,653
Company-obligated mandatorily redeemable preferred securities of subsidiary trust	-	-	-	-	-	100,000
Cash dividends declared on common stock (7)	53,968	46,289	-	-	-	-

(1) Includes the impact of significant acquisitions and sales of assets. See *Item 8. Financial Statements and Supplementary Data, Note 3 – Acquisitions and Sales* and *Item 8. Financial Statements and Supplementary Data, Note 19 – Discontinued Operations* for information related to the acquisitions and sales.

(2) The Company's investment in CCE Holdings, which was accounted for using the equity method, was included in the Company's Consolidated Balance Sheet at December 31, 2004. The Company's share of net income from CCE Holdings was recorded as *Earnings from unconsolidated investments* in the Company's Consolidated Statement of Operations since its acquisition on November 17, 2004. For these reasons, the Consolidated Statement of Operations for the periods subsequent to such acquisition is not comparable to the year of acquisition.

(3) Panhandle was acquired on June 11, 2003 and was accounted for as a purchase. The Panhandle assets were included in the Company's Consolidated Balance Sheet at June 30, 2003 and its results of operations have been included in the Company's Consolidated Statement of Operations since its acquisition on June 11, 2003. For these reasons, the Consolidated Statement of Operations for the periods subsequent to such acquisition is not comparable to the year of acquisition.

(4) Net earnings from continuing operations are net of dividends on preferred stock of $17.4 million, $17.4 million, $17.4 million, $8.7 million and $12.7 million for the years ended December 31, 2007, 2006 and 2005, the six months ended December 31, 2004 and the year ended June 30, 2004, respectively. For additional related information, see *Item 8. Financial Statements and Supplementary Data, Note12 – Preferred Securities.*

(5) On August 24, 2006, the Company completed the sales of the assets of its PG Energy natural gas distribution division to UGI Corporation and the Rhode Island operations of its New England Gas Company natural gas distribution division to National Grid USA. On January 1, 2003, ONEOK acquired the Company's Southern Union Gas natural gas operating division and related assets. These dispositions were accounted for as discontinued operations in the Consolidated Statement of Operations. For

additional related information, see *Item 8. Financial Statements and Supplementary Data, Note 19 – Discontinued Operations.*

(6) Earnings per share for all periods presented were computed based on the weighted average number of shares of common stock and common stock equivalents outstanding during the period, adjusted for the five percent stock dividends distributed on September 1, 2005, August 31, 2004, July 31, 2003 and July 15, 2002.

(7) No cash dividends on common stock were paid during the reporting periods prior to 2006. See *Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities* and *Item 8. Financial Statements and Supplementary Data, Note 10 – Stockholders' Equity – Dividends*.

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ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

INTRODUCTION

This Management's Discussion and Analysis of Financial Condition and Results of Operations is provided as a supplement to the accompanying consolidated financial statements and notes to help provide an understanding of Southern Union's financial condition, changes in financial condition and results of operations. The following section includes an overview of the Company's business as well as recent developments that the Company believes are important in understanding its results of operations, and to anticipate future trends in those operations. Subsequent sections include an analysis of the Company's results of operations on a consolidated basis and on a segment basis for each reportable segment, and information relating to the Company's liquidity and capital resources, quantitative and qualitative disclosures about market risk and other matters.

The Company's business purpose is to provide gathering, processing, transportation, storage and distribution of natural gas and NGLs in a safe, efficient and dependable manner. The Company's reportable business segments are determined based on the way internal managerial reporting presents the results of the Company's various businesses to its executive management for use in determining the performance of the businesses and in allocating resources to the businesses as well as based on similarities in economic characteristics, products and services, types of customers, methods of distribution and regulatory environment. The Company operates in three reportable segments.

BUSINESS STRATEGY

The Company's strategy is focused on achieving profitable growth and enhancing stockholder value. The Company seeks to balance its entrepreneurial focus with respect to maximizing cash and capital appreciation return to shareholders with preservation of its investment grade credit ratings. The key elements of its strategy include the following:

- *Expanding through development of the Company's existing businesses.* The Company will continue to pursue growth opportunities through the expansion of its existing asset base, while maintaining its focus on providing safe and reliable service to its customers. In each of its business segments, the Company identifies opportunities for organic growth through incremental volumes and system enhancements to generate operating efficiencies. In its interstate transmission and distribution businesses, the Company seeks rate increases and/or improved rate design as appropriate to achieve a fair return on its investment. See *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – Investing Activities* for information related to the Company's principal capital expenditure projects. *See Item 8. Financial Statements and Supplementary Data, Note 16 – Regulation and Rates* for information related to ratemaking activities.

- *New initiatives.* The Company regularly assesses strategies to enhance stockholder value, including diversification of earning sources through strategic acquisitions or joint ventures in the diversified natural gas industry.

- *Disciplined capital expenditures and cost containment programs.* The Company will continue to focus on system optimization and cost savings while making prudent capital expenditures across its base of energy infrastructure assets.

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RESULTS OF OPERATIONS

Overview

The Company believes that its completed and ongoing expansion of Panhandle's asset base, its acquisition of Sid Richardson Energy Services on March 1, 2006, its investment in CCE Holdings on November 17, 2004 and the related CCE Holdings redemption transaction with Energy Transfer more fully described below, and the sale of the assets of its PG Energy natural gas distribution division and the Rhode Island operations of its New England Gas Company natural gas distribution division represent significant steps undertaken by the Company in its transformation into a higher return business with significant growth opportunities.

The Company evaluates operational and financial segment performance using several factors, of which the primary financial measure is EBIT, which is a non-GAAP measure. The Company defines EBIT as *Net earnings available for common stockholders*, adjusted for the following:

- items that do not impact net earnings from continuing operations, such as extraordinary items, discontinued operations and the impact of changes in accounting principles;
- income taxes;
- interest; and
- dividends on preferred stock.

EBIT may not be comparable to measures used by other companies and should be considered in conjunction with net earnings and other performance measures such as operating income or operating cash flow.

The following table provides a reconciliation of EBIT (by segment) to *Net earnings available for common stockholders*.

	Years Ended December 31,		
	2007	2006	2005
		(In thousands)	
EBIT:			
Transportation and storage segment	$ 391,029	$ 417,536	$ 281,344
Gathering and processing segment	65,368	62,630	-
Distribution segment	70,568	41,883	61,698
Corporate and other	151	14,324	(11,424)
Total EBIT	527,116	536,373	331,618
Interest expense	203,146	210,043	128,470
Earnings from continuing operations before income taxes	323,970	326,330	203,148
Federal and state income taxes	95,259	109,247	50,052
Earnings from continuing operations	228,711	217,083	153,096
Discontinued operations:			
Loss from discontinued operations before income taxes	-	(2,369)	(111,588)
Federal and state income taxes	-	150,583	20,825
Loss from discontinued operations	-	(152,952)	(132,413)
Preferred stock dividends	17,365	17,365	17,365
Net earnings available for common stockholders	$ 211,346	$ 46,766	$ 3,318

Year ended December 31, 2007 versus the year ended December 31, 2006. The Company's $164.6 million increase in *Net earnings available for common stockholders* was primarily due to:

- Impact of the $153 million loss from discontinued operations in the 2006 period associated with the August 2006 sales of the assets of the Company's PG Energy natural gas distribution division and the Rhode Island operations of its New England Gas Company natural gas distribution division;

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- Higher EBIT contributions of $28.7 million from the Distribution segment primarily due to higher net operating revenue resulting from the Missouri Gas Energy rate increase effective April 3, 2007 eliminating the impact of weather and conservation for residential margin revenues;
- Lower interest expense of $6.9 million primarily due to the retirement of debt in 2006 associated with the bridge loan facility entered into to finance the acquisition of the Sid Richardson Energy Services business, partially offset by increased interest expense related to the $600 million Junior Subordinated Notes issued in October 2006 and higher interest expense on Panhandle debt primarily due to higher debt balances; and
- Lower income tax expense from continuing operations of $14 million primarily due to the lower federal and state effective income tax rate (*EITR*) of 29 percent in the 2007 period versus 33 percent in the 2006 period primarily due to the tax benefit associated with the increase in the dividends received deduction as a result of increased dividends from the Company's unconsolidated investment in Citrus.

These earnings improvements were partially offset by:

- Lower EBIT contributions of $26.5 million from the Transportation and Storage segment largely due to the gain on CCE Holdings' exchange of Transwestern in 2006, partially offset by higher LNG terminalling revenue associated with the Trunkline LNG Phase I and Phase II expansions completed in April 2006 and July 2006, respectively, higher pipeline reservation revenues driven by higher average rates on contracts, higher parking revenues and higher equity earnings from Citrus resulting from the Company's increased equity ownership in Citrus from 25 percent to 50 percent effective December 1, 2006; and
- Impact of the pre-acquisition pre-tax mark-to-market gain of $37.2 million in the 2006 period on the put options associated with the acquisition of the Sid Richardson Energy Services business, partially offset by $12.8 million of executive bonus compensation awarded and paid in 2006.

Year ended December 31, 2006 versus the year ended December 31, 2005. The Company's $43.4 million increase in earnings was primarily attributable to improved earnings from Panhandle largely due to higher LNG terminalling revenue resulting from the LNG terminal enhancement construction projects completed during 2006, the earnings contribution from SUGS, which was acquired on March 1, 2006, and increased equity earnings primarily due to the gain on CCE Holdings' exchange of Transwestern, partially offset by higher interest expense, most of which was related to debt and debt issuance costs associated with the SUGS acquisition, and losses and taxes associated with the sales of the assets of the Company's PG Energy natural gas distribution division and the Rhode Island operations of its New England Gas Company natural gas distribution division.

Business Segment Results

Transportation and Storage Segment. The Transportation and Storage segment is primarily engaged in the interstate transportation and storage of natural gas in the Midwest and from the Gulf Coast to Florida, and LNG terminalling and regasification services. Prior to the completion of the Redemption Agreement on December 1, 2006, the Transportation and Storage segment also provided service to the Southwest region through its interests in Transwestern. The Transportation and Storage segment's operations, now conducted through Panhandle and Florida Gas, are regulated as to rates and other matters by FERC. Demand for gas transmission on Panhandle's pipeline systems is seasonal, with the highest throughput and a higher portion of annual total operating revenues and EBIT occurring in the traditional winter heating season in the first and fourth calendar quarters. Florida Gas' pipeline system experiences the highest throughput in the summer period due to gas-fired generation loads in the second and third calendar quarters.

Historically, much of the Transportation and Storage segment's business was conducted through long-term contracts with customers. Over the past decade, some customers within the segment have shifted to shorter term transportation services contracts. This overall shift, which can increase the volatility of revenues, is primarily due to changes in market conditions and competition with other pipelines, changing supply sources and volatility in natural gas prices. Average reservation revenue rates realized by the Company are dependent on certain factors, including but not limited to rate regulation, customer demand for reserved capacity, capacity sold levels for a given period and, in some cases, utilization of capacity. Commodity revenues, which are more short-term sensitive in nature, are dependent upon a number of variable factors including weather, storage levels, and customer demand for firm, interruptible and parking services. The majority of the Transportation and Storage segment revenues are related to firm capacity reservation charges. For additional information related to Transportation and Storage segment risk factors and the weighted average remaining lives of firm transportation and storage contracts, see *Item 1A. Risk Factors – Risks that Relate to the Company's Transportation and*

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Storage Segment, and *Item 1. Business – Business Segments – Transportation and Storage Segment*, respectively.

The Company's regulated transportation and storage businesses periodically file for changes in their rates, which are subject to approval by FERC. Changes in rates and other tariff provisions resulting from these regulatory proceedings have the potential to negatively impact the Company's results of operations and financial condition. For information related to the status of current rate filings, see *Item 1. Business – Business Segments – Transportation and Storage Segment.*

The following table illustrates the results of operations applicable to the Company's Transportation and Storage segment for the periods presented:

	Years Ended December 31,		
Transportation and Storage Segment	**2007**	**2006**	**2005**
		(In thousands)	
Operating revenues	$ 658,446	$ 577,182	$ 505,233
Operating expenses	252,903	206,181	204,711
Depreciation and amortization	85,641	72,724	62,171
Taxes other than on income and revenues	29,699	25,405	28,196
Total operating income	290,203	272,872	210,155
Earnings from unconsolidated investments	99,222	141,310	70,618
Other income, net	1,604	3,354	571
EBIT	$ 391,029	$ 417,536	$ 281,344
Operating information:			
Panhandle natural gas volumes transported (in trillion British thermal units (TBtu))	1,454	1,180	1,214
CCE Holdings natural gas volumes transported (TBtu) (1)			
Florida Gas	751	737	699
Transwestern	-	572	589

(1) Represents 100 percent of Florida Gas and Transwestern natural gas volumes transported versus the Company's effective equity ownership interests. The Company's effective equity ownership interests in Florida Gas and Transwestern were 25 percent and 50 percent, respectively, until December 1, 2006, when the Company's indirect interest in Transwestern was transferred to Energy Transfer, increasing the Company's effective indirect ownership interest in Florida Gas to 50 percent.

See *Item 1. Business – Business Segments – Transportation and Storage Segment* for additional related operational and statistical information associated with the Transportation and Storage segment.

Year ended December 31, 2007 versus the year ended December 31, 2006. The $26.5 million EBIT reduction in the year ended December 31, 2007 versus the same period in 2006 was primarily due to lower equity earnings from unconsolidated investments of $42.1 million, now primarily consisting of the Company's investment in Citrus, offset by improved contributions from Panhandle totaling $15.6 million.

Panhandle's $15.6 million EBIT increase was primarily related to the following items:

- Higher operating revenues of $81.3 million as the result of:
  - Increased transportation and storage revenue of $59.8 million attributable to:
    - o Higher transportation reservation revenues of $27.4 million primarily due to reduced discounting resulting in higher average rates realized on contracts driven by higher customer demand and utilization of contract capacity;
    - o Higher parking revenues of $18 million resulting from customer demand for parking services and market conditions;
    - o Higher storage revenues of $7.8 million due to increased contracted capacity; and

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- o Higher other commodity revenues of $6.5 million due to higher throughput volumes including transportation of higher LNG volumes on Trunkline, higher volumes on Sea Robin due to adverse hurricane impacts on 2006 throughput, and higher throughput on Panhandle due to storage refill activity.
- A $23.6 million increase in LNG terminalling revenue based on a capacity increase on the BG LNG Services contract as a result of the Trunkline LNG Phase I and Phase II expansions, which were placed in service in April 2006 and July 2006, respectively, as well as higher volumes resulting from an increase in LNG cargoes; and
- A decrease in other revenue of $2.2 million primarily due to higher operational sales of gas in 2006.

These increased revenues were offset by:

- Higher operating expenses of $46.7 million as the result of:
  - o A $15.6 million increase in corporate services costs relating to Southern Union's disposition of certain assets during 2006, resulting in a larger allocation of corporate services costs to the remaining business units;
  - o A $13.1 million increase in contract storage costs attributable to an increase in leased capacity;
  - o A $6.2 million increase in LNG power costs resulting from increased cargoes;
  - o A $3.4 million increase in fuel tracker costs primarily due to a net under-recovery in 2007;
  - o A $2.4 million net increase in labor and benefits primarily due to incentive and merit increases; and
  - o A $1.8 million increase in insurance due to higher premiums.
- Increased depreciation and amortization expense of $12.9 million due to a $411.2 million increase in property, plant and equipment placed in service in 2007. Depreciation and amortization expense is expected to continue to increase primarily due to higher capital spending, including compression modernization and other expenditures; and
- Higher taxes other than on income of $4.3 million primarily due to a $2.8 million refund received in 2006 for franchise and sales taxes and higher property and compressor fuel taxes in 2007.

Equity earnings were lower by $42.1 million in 2007 versus 2006 primarily due to the following items, adjusted where applicable to reflect the Company's proportionate equity share:

- $74.8 million nonrecurring gain in 2006 resulting from the transfer of Transwestern to Energy Transfer in December 2006 in connection with the redemption of Energy Transfer's interest in CCE Holdings pursuant to the Redemption Agreement;
- $28 million of earnings in 2006 attributable to Transwestern;
- Higher equity earnings of approximately $42 million from Citrus' core business largely due to the increase in the Company's effective ownership from 25 percent to 50 percent as a result of the transactions under the Redemption Agreement, which closed in December 2006;
- A $7.6 million gain in 2007 related to a reduction in a previously established liability to Enron associated with the Duke lawsuit;
- A gain of $7.5 million recognized by Citrus in 2007 associated with settlement of the Duke lawsuit; and
- A $3.6 million gain in 2007 related to the sale of Enron bankruptcy claim receivables.

The Company's indirect interest in Transwestern was transferred to Energy Transfer in December 2006 in connection with the redemption of Energy Transfer's interest in CCE Holdings pursuant to the Redemption Agreement.

Year ended December 31, 2006 versus the year ended December 31, 2005. The $136.2 million EBIT improvement in the year ended December 31, 2006 versus the same period in 2005 was primarily due to improved contributions from Panhandle totaling $65.5 million and higher equity earnings from the Company's investment in CCE Holdings of $70.7 million, including a $74.8 million non-recurring gain.

Panhandle's $65.5 million EBIT improvement was primarily related to the following items:

- Higher operating revenues of $71.9 million primarily due to:
  - o A $49.3 million increase in LNG terminalling revenue primarily due to expanded vaporization capacity, a base capacity increase on the BG LNG Services contract and higher volumes resulting from an increase in LNG cargoes;

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  - o Increased transportation and storage revenue of $17 million due to higher reservation revenues of $15.6 million, which were primarily driven by higher average rates on contracts, higher parking revenues of $1.6 million and higher storage revenues of $4.7 million due to increased contracted capacity. These increases were partially offset by lower usage revenues of $4.9 million, of which $3.1 million resulted from the 2006 impact on Sea Robin in 2006 of the hurricanes that occurred in the third quarter of 2005 and $1.8 million resulted from lower overall capacity utilization at Trunkline; and
  - o Increased other revenue of $5.7 million primarily due to $3.7 million of non-recurring operational sales of gas in 2006 and $1.1 million of higher liquids revenue.

- Higher operating expenses of $1.5 million primarily due to:
  - o Approximately $3.2 million of higher pipeline integrity assessment costs;
  - o Approximately $1.6 million of higher maintenance project costs;
  - o $1.3 million for 2006 inspections of facilities due to Hurricane Rita;
  - o $2.1 million of higher LNG fuel and electric power tracker costs associated with greater LNG cargo activity;
  - o A $3.8 million nonrecurring adjustment in 2005 for lower vacation accruals due to a change in vacation pay practice; and
  - o Favorable offsetting impact of a $9.7 million decrease in insurance related costs due to accrued losses recorded in 2005 associated with the hurricanes and lower 2006 premiums and a $4.4 million decrease in benefit costs primarily related to lower postretirement benefit expenses including the impact of enactment of Medicare Part D reimbursements and benefit plan changes;
- Increased depreciation and amortization expense of $10.6 million due to an increase in property, plant and equipment placed in service in 2006, including the Trunkline LNG Phase I and Phase II expansions;
- Favorable offsetting impact of decreased taxes other than on income of $2.8 million primarily due to refunds of franchise and sales taxes received in 2006; and
- Favorable offsetting impact of a $2.8 million increase in other income, net primarily due to a gain on sale of certain Trunkline assets in 2006.

Equity earnings were higher by $70.7 million primarily due to:

- A nonrecurring gain of $74.8 million resulting from the transfer of Transwestern pursuant to the Redemption Agreement in 2006;
- Higher earnings from Florida Gas of $5.5 million, $2.8 million of which related to the December 2006 incremental earnings resulting from the Company's additional 25 percent indirect ownership interest in Florida Gas as a result of the transactions under the Redemption Agreement;
- Lower earnings from discontinued operations of $10.6 million (adjusted to reflect the Company's 50 percent share) related to Transwestern primarily due to:
  - o Lower net revenues of $4.8 million primarily related to the $8 million impact of a decrease in transportation volumes associated with the replacement of expired contracts at discounted rates, partially offset by $3.2 million of increased operational gas sales revenue;
  - o Higher operating expense of $5.5 million primarily related to higher system balancing expenses of $3.7 million and $2 million of higher electricity costs due to the addition of San Juan compression;
  - o A decrease of $1.9 million in net earnings attributable to Transwestern because 2006 contained only eleven months versus a full year of operations in 2005 due to the redemption of Transwestern on December 1, 2006; and
  - o Favorable offsetting impact of lower depreciation expense of $2.4 million due to the cessation of depreciation on Transwestern following the execution of the Redemption Agreement with Energy Transfer.

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Gathering and Processing Segment. The Gathering and Processing segment is primarily engaged in connecting wells of natural gas producers to its gathering system, treating natural gas to remove impurities to meet pipeline quality specifications, processing natural gas for the removal of NGLs, and redelivering natural gas and NGLs to a variety of markets. The results of operations provided by SUGS have been included in the Consolidated Statement of Operations since its March 1, 2006 acquisition.

The following table presents the results of operations applicable to the Company's Gathering and Processing segment:

	Years Ended December 31,	
Gathering and Processing Segment	**2007**	**2006 (1)**
Gross margin (2)	$ 210,780	$ 172,152
Operating expenses	84,550	61,428
Depreciation and amortization	59,560	47,321
Taxes other than on income and revenues	2,742	2,156
Total operating income	63,928	61,247
Earnings (loss) from unconsolidated investments	1,300	(188)
Other income, net	140	1,571
EBIT	$ 65,368	$ 62,630
Operating Statistics:		
Volumes		
Avg natural gas processed (MMBtu/d)	426,097	451,675
Avg NGLs produced (gallons/d)	1,337,450	1,423,138
Avg natural gas wellhead (MMBtu/d)	637,794	585,185
Natural gas sales (MMBtu)	105,677,108	113,362,236
NGLs sales (gallons)	469,907,600	421,896,247
Average Pricing		
Realized natural gas ($/MMBtu)	$ 6.26	$ 5.83
Realized NGLs ($/gallon)	1.13	0.97
Natural Gas Daily WAHA ($/MMBtu)	6.35	5.78
Natural Gas Daily El Paso ($/MMBtu)	6.20	5.68
Estimated plant processing spread ($/gallon)	0.55	0.43

(1) Represents results of operations for the period March 1, 2006 (date of acquisition) through December 31, 2006.
(2) Gross margin consists of *Operating revenues* less *Cost of gas and other energy*. The Company believes that this measurement is more meaningful for understanding and analyzing the Gathering and Processing segment's operating results for the periods presented because commodity costs are a significant factor in the determination of the segment's revenues.

Year ended December 31, 2007 versus the year ended December 31, 2006. The $2.7 million EBIT increase for the year ended December 31, 2007 versus the post-acquisition ten-month period ended December 31, 2006 was primarily due to the following items:

- Gross margin was higher by $38.6 million primarily due to:
  - Realization of operating results for the complete twelve-month period in 2007 versus ten months in the 2006 period;
  - Favorable impact of market-driven higher average realized natural gas and NGLs prices of $6.26 per MMBtu and $1.13 per gallon in the 2007 period versus $5.83 per MMBtu and $0.97 per gallon in the 2006 period, respectively; and
  - Higher producer fee revenues of $5 million primarily due to increased volumes from the Atoka producing region associated with the Company's Mi Vida system.

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The favorable gross margin impact was partially offset by unusually high levels of fuel, flare and unaccounted for gas losses in the 2007 period versus the 2006 period primarily attributable to capacity and treating limitations experienced during 2007 at the Jal Plant treating facility;

- Operating expenses were higher by $23.1 million primarily due to:
  - Incurrence of twelve months of activity in the 2007 period versus ten months in the 2006 period;
  - A $4.9 million increase in corporate services costs relating to Southern Union's disposition of certain assets during 2006, resulting in a larger allocation of corporate services costs to the remaining business units; and
  - Increases in operating costs such as employee labor and benefit costs and contractor services costs resulting from competitive forces within the midstream energy industry, as well as higher costs incurred for chemical and lubricant petroleum products used in SUGS' gathering and processing operations;
- Depreciation and amortization expense was higher by $12.2 million primarily due to the incurrence of twelve months of activity in the 2007 period versus ten months in the 2006 period and a $57.5 million increase in property, plant and equipment placed in service in 2007;
- Earnings (loss) from unconsolidated investments increased by $1.5 million primarily due to the Company's proportionate equity share of $463,000 related to a settlement with a producer for damages incurred from sour gas delivered into the Grey Ranch facility and the benefit derived from improved operating efficiencies realized at the Grey Ranch facility; and
- Other income, net decreased by $1.4 million primarily due to approximately $911,000 of lower interest income resulting from higher available cash balances for investment purposes in the 2006 period versus the 2007 period, principally due to the $53.7 million of cash on hand at the March 1, 2006 acquisition date.

To alleviate the treating limitations discussed above related to the Jal Plant, the Company completed construction of an 18-mile, 16-inch high pressure pipeline to utilize existing treating capacity at the Keystone Plant. The pipeline was put into service on June 21, 2007 at an approximate cost of $6.1 million. The Company is exploring other expansion opportunities to provide additional growth capacity and further improve system operating efficiency.

Economic Hedging Activities. The Company realizes NGL and/or natural gas volumes from its contractual arrangements associated with gas processing services it provides. The Company utilizes various economic hedge techniques to manage its price exposure of Company owned volumes, including processing spread puts and natural gas swaps. Expected NGL and/or natural gas volumes compared to the actual volumes sold and the effectiveness of the associated economic hedges utilized by the Company can be unfavorably impacted by:

- Processing plant outages;
- Higher than anticipated FF&U efficiency levels;
- Impact of commodity prices in general;
- Lower than expected recovery of NGLs from the residue gas stream; and
- Lower than expected recovery of natural gas volumes to be processed.

For the purpose of reducing its processing spread exposure, the Company purchased put options for the period February 1, 2008 through December 31, 2008. The put options reduce its processing spread exposure on 11,075 MMBtu/day, or approximately 25 percent of the Company's expected NGLs sales volumes based on 2007 historical processing trends. The put options set a floor for the Company's processing spread at $8.15 per MMBtu for such volumes. The cost of the December 2007 transaction was $5.2 million, or $1.41 per MMBtu.

Additionally, in February 2008, for the period March 1, 2008 through December 31, 2008, the Company entered into various natural gas swaps which have reduced its commodity price exposure related to 30,000 MMBtu/day. The natural gas swaps have effectively established an average fixed index price at locations where we sell natural gas, at the "basis adjusted price" of $8.28 per MMBtu for the related period. The combination of the processing spread put option with an equal MMBtu portion of the natural gas swap effectively establishes a floor of $15.02 per MMBtu for 25 percent of the Company's expected NGL sales volumes as noted above. In February 2008, the Company also entered into natural gas swaps associated with 10,000 MMBtu/day for the period January 1, 2009 through December 31, 2009, fixing the 2009 basis adjusted sales price of such volumes at $8.19 per MMBtu.

For further information related to SUGS' commodity-based put options and non-heding derivative instruments, see *Item 8. Financial Statements and Supplementary Data, Note 11 – Derivative Instruments and Hedging Activities – Gathering and Processing Segment*.

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Distribution Segment. The Distribution segment is primarily engaged in the local distribution of natural gas in Missouri and Massachusetts. The Company's utilities operations are regulated as to rates and other matters by the regulatory commissions of the states in which each operates. For information related to the status of current rate filings relating to the Distribution segment, see *Item 1. Business – Business Segments – Distribution Segment*. The utilities operations have historically been sensitive to weather and are seasonal in nature, with a significant percentage of annual operating revenues and EBIT occurring in the traditional winter heating season in the first and fourth calendar quarters. However, the MPSC approved distribution rates effective April 3, 2007 for Missouri Gas Energy's residential customers (which comprise approximately 87 percent of its total customers and approximately 67 percent of its operating revenues) that eliminate the impact of weather and conservation for residential margin revenues and related earnings in Missouri.

The following table illustrates the results of operations applicable to the Company's Distribution segment for the periods presented:

	Years Ended December 31,		
Distribution Segment	**2007**	**2006**	**2005**
		(In thousands)	
Net operating revenues (1)	$ 222,097	$ 174,584	$ 184,257
Operating expenses	108,788	90,178	87,306
Depreciation and amortization	30,251	30,353	29,447
Taxes other than on income and revenues	10,588	10,040	3,208
Total operating income	72,470	44,013	64,296
Other income (expenses), net	(1,902)	(2,130)	(2,598)
EBIT	$ 70,568	$ 41,883	$ 61,698

(1) Operating revenues for the Distribution segment are reported net of *Cost of gas and other energy* and *Revenue-related taxes*, which are both pass-through costs.

See *Item 1. Business – Business Segments – Distribution Segment* for additional related operational and statistical information related to the Distribution segment.

Year ended December 31, 2007 versus the year ended December 31, 2006. The $28.7 million EBIT improvement in the year ended December 31, 2007 versus the same period in 2006 was primarily due to the following items:

- Net operating revenues increased $47.5 million primarily due to the Missouri Gas Energy $27.2 million annual revenue rate increase effective April 3, 2007 and higher consumption volumes resulting from colder weather in 2007 versus 2006 as evidenced by a 13.8 percent increase in consumption volumes and a 14 percent increase in degree days;
- The net operating revenues increase was partially offset by higher operating expenses of $18.6 million in the 2007 period versus the 2006 period primarily due to:
  - Increased benefit costs of approximately $7.1 million primarily due to higher pension costs resulting from the recent Missouri Gas Energy rate case;
  - Increased general expenses of approximately $4.5 million primarily due to cathodic protection maintenance, the establishment of a customer education program for energy efficiency associated with the 2007 rate case and other costs;
  - Increased labor expenses of approximately $5.5 million primarily due to the filling of vacant positions and incentive and merit increases in 2007 versus 2006;
  - Higher uncollectible accounts of approximately $1.8 million resulting primarily from higher revenues realized in the 2007 period versus the 2006 period.

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Year ended December 31, 2006 versus the year ended December 31, 2005. The $19.8 million EBIT reduction in the year ended December 31, 2006 versus the same period in 2005 was primarily due to the following items:

- Net operating revenues were $9.7 million lower primarily due to a 12.6 percent reduction in consumption volumes resulting from the warmer than normal weather, as evidenced by a 15 percent reduction in degree days;
- Higher taxes other than on income and revenues of $6.8 million primarily due to refunds received for Missouri property tax settlements in 2005; and
- Higher operating expenses of $2.9 million primarily due to higher bad debt expenses of $900,000 due to the residual effects of higher gas prices in the 2005 to 2006 winter season and higher general expenses in 2006 of $1.3 million primarily due to higher corrosion control costs resulting from drier weather in 2006 compared to 2005.

Corporate and Other

Year ended December 31, 2007 versus the year ended December 31, 2006. The $14.2 million EBIT reduction for the year ended December 31, 2007 versus the same period in 2006 was primarily due to the following items:

- Impact of a mark-to-market gain in 2006 of $37.2 million on put options for the pre-acquisition period associated with the March 1, 2006 acquisition of the Sid Richardson Energy Services business; and
- Favorable offsetting impact of a decrease in operating expenses in 2007 versus 2006 due to executive bonus compensation of $12.8 million awarded by the compensation committee of the Company's Board of Directors in 2006 in respect of transactional activity and a $10.7 million increase in corporate services costs allocated to the Company's business units in 2007.

Year ended December 31, 2006 versus the year ended December 31, 2005. The $25.7 million EBIT improvement for the year ended December 31, 2006 versus the same period in 2005 was primarily due to the following items:

- A mark-to-market gain of $37.2 million on put options for the pre-acquisition period associated with the March 1, 2006 acquisition of Sid Richardson Energy Services;
- Negative impact of $12.8 million of executive bonus compensation awarded and paid in 2006;
- Negative impact of a $6.5 million write-down in the carrying value of the Scranton corporate building recorded in 2006;
- Negative impact of $1.4 million of corporate stock-based compensation costs resulting from the implementation of and accounting under Financial Accounting Standards Board (*FASB*) Statement No. 123(R), Accounting for Stock-Based Compensation in 2006;
- Impact of $3.8 million of non-cash compensation expense in the third quarter of 2005 related to separation agreements with former executives of the Company; and
- Charges of $6.3 million in the first quarter of 2005 to: (i) reserve for an other-than-temporary impairment in the Company's investment in a technology company, and (ii) record a liability for the guarantee by a subsidiary of the Company of a line of credit between the technology company and a bank.

Interest Expense

Year ended December 31, 2007 versus the year ended December 31, 2006. Interest expense was $6.9 million lower in 2007 compared with 2006 primarily due to:

- Impact of interest expense of $49.2 million and debt issuance cost amortization of $7.8 million in 2006 associated with the bridge loan facility entered into to finance the acquisition of the Sid Richardson Energy Services business, which was retired using approximately $1.1 billion in net proceeds from the sale of certain assets in August 2006 and funds obtained in October 2006 from the issuance of the $600 million Junior Subordinated Notes;
- Lower interest expense of $6 million associated with borrowings under the Company's credit agreements primarily due to lower average outstanding balances in 2007 compared to 2006;
- Lower interest expense of $2.2 million due to the retirement of the 2.75% Senior Notes in August 2006;

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- Lower interest expense of $1.6 million associated with interest owed to Missouri Gas Energy's ratepayers in connection with its purchased gas cost recovery mechanism primarily due to higher levels of overcollections in 2006;
- Partially offset by increased interest expense of $34.9 million related to the $600 million Junior Subordinated Notes issued in October 2006;
- Partially offset by increased interest expense of $20.6 million related to Panhandle debt primarily due to higher debt balances in 2007 versus 2006; and
- Partially offset by increased interest expense of $4.8 million under the 6.15% Senior Notes issued in August 2006.

Year ended December 31, 2006 versus the year ended December 31, 2005. Interest expense was $81.6 million higher in 2006 compared with 2005 primarily due to:

- Interest expense of $49.2 million and debt issuance cost amortization of $7.8 million associated with the bridge loan facility entered into to finance the acquisition of the Sid Richardson Energy Services business;
- Increased interest expense of $10.8 million related to Panhandle debt primarily due to higher average interest rates in 2006 versus 2005;
- Interest expense of $2.5 million under the $465 million 2006 Term Loan;
- Interest expense of $8.3 million related to the $600 million Junior Subordinated Notes issued in 2006; and
- Increased interest expense of $4.4 million associated with borrowings under the Company's credit agreements primarily due to higher average outstanding balances and higher interest rates in 2006 compared to 2005.

Federal and State Income Taxes from Continuing Operations

Year ended December 31, 2007 versus the year ended December 31, 2006. The EITR from continuing operations for the years ended December 31, 2007 and 2006 was 29 percent and 33 percent, respectively. The decrease in the EITR from continuing operations was primarily due to:

- Tax benefits of $30.9 million in 2007 versus $11.5 million in 2006 associated with the increase in the dividends received deduction as a result of increased dividends from the Company's unconsolidated investment in Citrus;
- Reduced tax expense of $523,000 in 2007 versus $5.4 million in 2006 associated with the decrease in nondeductible executive compensation; and
- Partially offset by the release of $9.4 million of tax reserves in 2006 for uncertain tax positions established in prior years due to the completion of the Internal Revenue Service (*IRS*) audit for the fiscal year ended June 30, 2003 and expiring state statutes.

Year ended December 31, 2006 versus the year ended December 31, 2005. The EITR from continuing operations for the years ended December 31, 2006 and 2005 was 33 percent and 25 percent, respectively. The fluctuation in the EITR from continuing operations was primarily due to:

- The release in 2005 of an $11.9 million valuation allowance, which was originally established in 2004 for a deferred tax asset related to the difference between the book and tax basis of the Company's investment in CCE Holdings. The Company determined that this valuation allowance was no longer necessary because the book income from CCE Holdings was substantially greater than the taxable income for 2005 and was expected to continue to be higher for the foreseeable future;
- The release in 2006 of $9.4 million of tax reserves for uncertain tax positions established in prior years due to the completion of the IRS audit for the fiscal year ended June 30, 2003 and expiring state statutes; and
- $5.4 million of additional taxes resulting from the $14.5 million of non-deductible executive compensation paid in 2006.

IRS Audit.

In November 2006, the IRS completed its examination of the Company's federal income tax return for the fiscal year ended June 30, 2003. The Company realized a favorable settlement regarding the like-kind exchange structure under Section 1031 of the Internal Revenue Code related to the sale of the assets of its Southern Union

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Gas natural gas operating division and related assets to ONEOK Inc. for approximately $437 million in January 2003 and the acquisition of Panhandle in June 2003.

The Company was successful in sustaining all but $26.3 million of the original estimated $90 million of income tax deferral associated with the like-kind structure. However, the Company's net tax due to the IRS was reduced to $11.6 million, plus interest, primarily due to alternative minimum tax credits and other favorable audit results. As a result of the IRS examination, the Company paid $12.6 million of income tax to the IRS in November 2006, received a refund of $1 million from the IRS and paid $1.4 million to state and local jurisdictions in 2007. The Company also paid $2.4 million ($1.5 million net of tax) in 2007 representing interest payable to the IRS, and state and local jurisdictions as a result of the IRS examination of the year ended June 30, 2003. No penalties were assessed against the Company in this IRS examination.

The Company will be entitled to recover a corresponding $26.3 million of future income tax benefit over time from additional depreciation deductions in respect of the Panhandle assets due to the higher tax basis in such assets as a result of the reduction of income tax benefits from the like-kind exchange.

Net Earnings from Discontinued Operations

Earnings (loss) from discontinued operations included in the 2006 period are associated with the assets of the Company's PG Energy natural gas distribution division and the Rhode Island operations of its New England Gas Company natural gas distribution division, which were sold in August 2006. See *Item 8. Financial Statements and Supplementary Data, Note 19 – Discontinued Operations* for additional information.

Year ended December 31, 2006 versus the year ended December 31, 2005. *Earnings from discontinued operations before income taxes* for the year ended December 31, 2006 versus the same period in 2005 were $109.2 million higher primarily due to the $175 million goodwill impairment recognized in 2005, partially offset by a loss of $56.8 million resulting from the sales of assets in 2006 and lower earnings of $8.9 million primarily due to the inclusion of a full year of activity in 2005 versus activity only through August 24 in 2006. Significant components contributing to the $56.8 million loss include $19.4 million of asset impairment charges related to increases in plant, property and equipment during 2006, selling costs of $4.7 million, and charges associated with pre-closing arrangements between the Company and UGI Corporation and National Grid USA, principally consisting of $15.1 million of pension funding requirements and $5.8 million of premiums related to early retirement of debt.

The Company's EITR from discontinued operations was significantly higher in 2006 compared to 2005 primarily due to the following items that resulted from the sale of the assets of the PG Energy natural gas distribution division and the Rhode Island operations of the New England Gas Company natural gas distribution division:

- The Company incurred $142.4 million of income tax expense in 2006 resulting from $379.8 million of non-deductible goodwill related to the disposition of these assets in 2006 compared to $65.6 million of income tax expense resulting from $175 million of non-deductible goodwill impairment related to these assets recorded in 2005; and
- The Company incurred income tax expense of $17.6 million in 2006 as a result of the write-off of a tax-related regulatory asset of PG Energy.

LIQUIDITY AND CAPITAL RESOURCES

Cash generated from internal operations constitutes the Company's primary source of liquidity. The Company's $515.4 million working capital deficit at December 31, 2007 is primarily comprised of $425 million of debt maturing in August 2008. The Company plans to refinance its $425 million of debt maturing in August 2008 with new capital market debt or bank financings. See *Item 1A. Risk Factors* for additional information related to the refinancing. Additional sources of liquidity include use of available credit facilities, project and bank financings and proceeds from asset dispositions. The availability and terms relating to such liquidity will depend upon various factors and conditions such as the Company's combined cash flow and earnings, the Company's resulting capital structure and conditions in the financial markets at the time of such offerings. Acquisitions, which generally require a substantial increase in expenditures, and related financings also affect the Company's combined results. Future acquisitions or related financings or refinancings may involve the issuance of shares of the Company's common stock, which could have a dilutive effect on the then-current stockholders of the Company.

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Operating Activities

Year ended December 31, 2007 versus the year ended December 31, 2006. Cash flows provided by operating activities were $470.4 million for the year ended December 31, 2007 compared with cash flows provided by operating activities of $458.8 million for the same period in 2006. Cash flows provided by operating activities before changes in operating assets and liabilities for 2007 were $516.6 million compared with $393.6 million for 2006. Changes in operating assets and liabilities used cash of $46.2 million in 2007 and provided cash of $65.2 million in 2006, resulting in a decrease in cash of $111.4 million in 2007 compared to 2006. The $111.4 million decrease in cash is primarily due to the impact of $91.8 million of lower receivables from the Distribution segment attributable to higher December 2005 balances realized from the colder related winter period versus the subsequent winter periods and the receipt of $38.8 million less from cash settlements of put options in the Gathering and Processing segment in the 2007 period versus the 2006 period.

Year ended December 31, 2006 versus the year ended December 31, 2005. Cash flows provided by operating activities were $458.8 million for the year ended December 31, 2006 compared with cash flows provided by operating activities of $218.6 million for the same period in 2005. Cash flows provided by operating activities before changes in operating assets and liabilities for 2006 were $393.6 million compared with $356.6 million for 2005. Changes in operating assets and liabilities provided cash of $65.2 million in 2006 and used cash of $138 million in 2005, resulting in an increase in cash of $203.2 million in 2006 compared to 2005. The $203.2 million increase in cash is primarily due to the receipt in 2006 of $74.2 million from cash settlements of put options versus the purchase of $49.7 million of put options in 2005, higher net accounts receivable resulting from increased billings due to improved earnings and other increases of operating activities from the Gathering and Processing segment, partially offset by increased usage of cash primarily related to the replenishment of natural gas inventory levels in the 2006 period compared to 2005.

Investing Activities

Summary

The Company's business strategy includes making prudent capital expenditures across its base of interstate transmission, storage, gathering, processing and distribution assets and growing the businesses through the selective acquisition of assets in order to position itself favorably in the evolving North American natural gas markets.

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Cash flows used in investing activities in the years ended December 31, 2007 and 2006 were $666.6 million and $806.8 million, respectively. The $140.2 million decrease in invested cash is primarily due to the $1.54 billion (net of $53.7 million cash received) acquisition of the Sid Richardson Energy Services business completed on March 1, 2006, offset by the effect of the $1.08 billion disposition in August 2006 of the assets of the Company's PG Energy natural gas distribution division and the Rhode Island operations of its New England Gas Company natural gas distribution division. This decrease is partially offset by increased capital expenditures of $269 million for the same periods, primarily due to increased capital spending in the Transportation and Storage segment. The following table presents a summary of additions to property, plant and equipment in continuing operations by segment, including additions related to major projects for the periods presented.

	Years ended December 31,		
Property, Plant and Equipment Additions	**2007**	**2006**	**2005**
		(In thousands)	
Transportation and Storage Segment			
LNG Terminal Expansions/Enhancements	$ 133,469	$ 57,045	$ 75,263
Trunkline Field Zone Expansion	185,180	12,314	169
East End Enhancement	80,249	52,102	1,012
Compression Modernization	81,687	11,642	-
Other, primarily pipeline integrity, system reliability, information technology, air emission compliance	110,568	111,718	112,971
Total	591,153	244,821	189,415
Gathering and Processing Segment	48,633	35,101 (1)	-
Distribution Segment			
Missouri Safety Program	11,405	11,592	11,426
Other, primarily system replacement and expansion	33,364	36,362	73,470
Total	44,769	47,954	84,896
Corporate and other	4,173	4,798	2,306
Total (2)	$ 688,728	$ 332,674	$ 276,617

(1) Reflects expenditures for the period subsequent to the March 1, 2006 acquisition of Sid Richardson Energy Services.
(2) Includes net capital accruals totaling $71.8 million, $14.9 million and $(3.1) million for the years ended 2007, 2006 and 2005, respectively.

Principal Capital Expenditure Projects

The following is a summary of the Company's principal capital expenditure projects.

LNG Expansion Projects. Trunkline LNG's Phase I expansion project was placed into service on April 5, 2006 with a total project cost of $141 million, plus capitalized interest. The expanded vaporization capacity portion of the expansion was placed into service on September 18, 2005. Phase II went into service on July 8, 2006. The final cost of Phase II was $79 million, plus capitalized interest. The expansions increased sustainable send out capacity from .63 Bcf/d to 1.8 Bcf/d, and storage increased from 6.3 Bcf to 9 Bcf.

LNG Terminal Enhancement. The Company has commenced construction of an enhancement at its Trunkline LNG terminal. This infrastructure enhancement project, which was originally expected to cost approximately $250 million, plus capitalized interest, will increase send out flexibility at the terminal and lower fuel costs. Recent cost projections indicate the construction costs will likely be approximately $365 million, plus capitalized interest. The revised costs reflect increases in the quantities and cost of materials required, higher contract labor costs and an allowance for additional contingency funds, if needed. The negotiated rate with the project's customer, BG LNG Services, will be adjusted based on final capital costs pursuant to a contract-based formula. The project is now

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expected to be in operation in the second quarter of 2009. In addition, Trunkline LNG and BG LNG Services agreed to extend the existing terminal and pipeline services agreements through 2028, representing a five-year extension. Approximately $178.3 million and $40.8 million of costs are included in the line item *Construction work-in-progress* at December 31, 2007 and 2006, respectively.

Compression Modernization. The Company has received approval from FERC to modernize and replace various compression facilities on PEPL. Such replacements are ultimately expected to be made at eleven compressor stations, with three stations completed as of December 31, 2007. Three additional stations are in progress and planned to be completed by the end of 2009, with the remaining cost for these stations estimated at approximately $100 million, plus capitalized interest. Planning for the other five compressor stations on which construction has not yet begun is continuing, with the timing and scope of the work on these stations being evaluated on an individual station basis. The Company is also replacing approximately 32 miles of existing pipeline on the east end of the PEPL system at a current estimated cost of approximately $125 million, plus capitalized interest, which will further improve system integrity and reliability. The revised higher cost relates to various construction issues and delays which have resulted in current estimated in-service dates for the related facilities around the end of the first quarter of 2008 or in the second quarter of 2008. Approximately $124.7 million and $57.9 million of costs related to these projects are included in the line item *Construction work-in-progress* at December 31, 2007 and 2006, respectively.

Trunkline Field Zone Expansion Project. Trunkline has completed construction on its field zone expansion project. The expansion project included the north Texas expansion and creation of additional capacity on Trunkline's pipeline system in Texas and Louisiana to increase deliveries to Henry Hub. Trunkline has increased the capacity along existing rights-of-way from Kountze, Texas to Longville, Louisiana by approximately 625 MMcf/d with the construction of approximately 45 miles of 36-inch diameter pipeline. The project included horsepower additions and modifications at existing compressor stations. Trunkline has also created additional capacity to Henry Hub with the construction of a 13.5-mile, 36-inch diameter pipeline loop from Kaplan, Louisiana directly into Henry Hub. The Henry Hub lateral provides capacity of 1 Bcf/d from Kaplan, Louisiana to Henry Hub. The majority of the project was put into service in late December 2007 with the remainder placed in-service in February 2008. The Company currently estimates the final project costs will total approximately $250 million, plus capitalized interest. The estimated costs include a $40 million CIAC to a subsidiary of Energy Transfer, which was paid in January 2008 and is expected to be amortized over the life of the facilities. Approximately $26.4 million and $12.5 million of costs for this project are included in the line item *Construction work-in-progress* at December 31, 2007 and 2006, respectively, with $178.3 million closed to *Plant in service* in December 2007.

Hurricane Damage. Late in the third quarter of 2005, Hurricanes Katrina and Rita came ashore along the Upper Gulf Coast. These hurricanes caused damage to property and equipment owned by Sea Robin, Trunkline, and Trunkline LNG. As of December 31, 2007, the Company has incurred approximately $35 million of capital expenditures related to the hurricanes, primarily for replacement or abandonment of damaged property and equipment at Sea Robin and construction project delays at the Trunkline LNG terminal.

The Company anticipates reimbursement from its property insurance carriers for a significant portion of damages from the hurricanes in excess of its $5 million deductible. Such reimbursement is currently estimated by the Company's property insurance carrier ultimately to be limited to 70 percent of the portion of the claimed damages accepted by the insurance carrier, but the amount is subject to the level of total ultimate claims from all companies relative to the carrier's $1 billion total limit on payout per event. As of December 31, 2007, the Company has received payments of $7.6 million of the $19.5 million total estimated eligible recoveries from its insurance carriers. No receivables due from the insurance carriers have been recorded as of December 31, 2007.

In addition, after the 2005 hurricanes, the U.S. Mineral Management Service mandated inspections by leaseholders and pipeline operators along the hurricane tracks. The Company has detected exposed pipe and other facilities on Trunkline and Sea Robin that must be re-covered to comply with applicable regulations. Capital expenditures of approximately $3.7 million have been incurred as of December 31, 2007 to address these issues. The Company will seek recovery of these expense and capital amounts as part of the hurricane-related claims.

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Missouri Safety Program. Pursuant to a 1989 MPSC order, Missouri Gas Energy is engaged in a major gas safety program in its service territories (*Missouri Safety Program*). This program includes replacement of Company and customer-owned gas service and yard lines, the movement and resetting of meters, the replacement of cast iron mains and the replacement and cathodic protection of bare steel mains. In recognition of the significant capital expenditures associated with this safety program, the MPSC initially permitted the deferral and subsequent recovery through rates of depreciation expense, property taxes and associated carrying costs over a 10-year period. On August 28, 2003, the state of Missouri passed certain statutes that provided Missouri Gas Energy the ability to adjust rates periodically to recover depreciation expense, property taxes and carrying costs associated with the Missouri Safety Program, as well as investments in public improvement projects. The continuation of the Missouri Safety Program will result in significant levels of future capital expenditures. The Company incurred capital expenditures of $11.4 million in 2007 related to this program and estimates incurring approximately $141.3 million over the next 12 years, after which all service lines, representing about 40 percent of the annual safety program investment, will have been replaced.

For additional information related to the Company's strategy regarding other growth opportunities, see *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Business Strategy*.

Financing Activities

Summary

The Company continues to pursue opportunities to enhance its credit profile by reducing its ratio of total debt to total capital. At each of, December 31, 2007 and 2006, the Company's ratio of total debt to total capital was 61 percent. The issuance of common stock, equity units, preferred stock and asset sales and use of proceeds therefrom to reduce debt or limit use of debt in conjunction with acquisitions is continued evidence of the Company's commitment to strengthen its balance sheet and solidify its current investment grade status.

Cash flows provided by financing activities were $196.1 million and $336.8 million for the years ended December 31, 2007 and 2006, respectively. Financing activity cash flow changes were primarily due to the net impact of higher issuances of debt partially offset by higher payments on the revolving credit facilities in the 2006 period versus the 2007 period and the issuance of common stock in 2006.

Cash flows provided by financing activities were $336.8 million for the year ended December 31, 2006 compared with $50.8 million for the same period in 2005. Financing activity cash flow changes were primarily due to the net impact of acquisition financing and the repayment of such debt, net borrowings under the revolving credit facilities and the payment of common and preferred stock dividends.

Common Stock, Equity Units and Preferred Stock Issuances

On August 16, 2006, the Company remarketed the 2.75% Senior Notes. The interest rate on the Senior Notes was reset to 6.15 percent per annum effective on and after August 16, 2006. The Senior Notes will mature on August 16, 2008. On August 16, 2006, the Company issued 7,413,074 shares of common stock for $125 million in conjunction with the remarketing of its 2.75% Senior Notes.

On February 11, 2005, Southern Union issued 2,000,000 of its 5% Equity Units at a public offering price of $50 per unit, resulting in net proceeds, after underwriting discounts and commissions and other transaction related costs, of $97.4 million. Southern Union used the proceeds to repay the balance of the bridge loan used to fund a portion of the Company's investment in CCE Holdings (*CCE Holdings Bridge Loan*) and to repay borrowings under its credit facilities. Each 5% Equity Unit consisted of a 1/20th interest in a $1,000 principal amount of Southern Union's 4.375% Senior Notes due 2008 and a forward stock purchase contract that obligated the holder to purchase Southern Union common stock on February 16, 2008. On February 8, 2008, the Company remarketed the 4.375% Senior Notes. The interest rate on the Senior Notes was reset to 6.089 percent per annum effective on and after February 19, 2008. The Senior Notes will mature on February 16, 2010. On February 19, 2008, the Company issued 3,693,240 shares of common stock for $100 million in conjunction with the remarketing of its 4.375% Senior Notes. See *Item 8. Financial Statements and Supplementary Data, Note 25 – Subsequent Event*.

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For additional information related to the Company's remarketed debt obligations, see *Item 8. Financial Statements and Supplementary Data, Note 13 – Debt Obligations – Long-Term Debt* and *Note 25 – Subsequent Event*.

On February 9, 2005, Southern Union issued 14,913,042 shares of its common stock at $23.00 per share, resulting in net proceeds, after underwriting discounts and commissions, of $332.6 million. Southern Union used the net proceeds to repay a portion of the CCE Holdings Bridge Loan.

Debt Refinancing, Repayment and Issuance Activity

6.20% Senior Notes. On October 26, 2007, PEPL issued $300 million in senior notes due November 1, 2017 with an interest rate of 6.20 percent (*6.20% Senior Notes*). In connection with the issuance of the 6.20% Senior Notes, the Company incurred underwriting and discount costs of approximately $2.7 million. The debt was priced to the public at 99.741 percent, resulting in $297.3 million in proceeds to the Company. The proceeds were initially used to repay approximately $246 million outstanding under the credit facilities. The remaining proceeds of $51.3 million were invested by the Company and subsequently utilized to fund working capital obligations.

LNG Holdings Term Loans. On March 15, 2007, LNG Holdings, LLC (*LNG Holdings*), as borrower, and PEPL and Trunkline LNG, as guarantors, entered into a $455 million unsecured term loan facility due March 13, 2012 (*2012 Term Loan*). The interest rate under the 2012 Term Loan is a floating rate tied to a LIBOR rate or prime rate at the Company's option, in addition to a margin tied to the rating of PEPL's senior unsecured debt. The proceeds of the 2012 Term Loan were used to repay approximately $455 million in existing indebtedness that matured in March 2007, including the $200 million 2.75% Senior Notes and the LNG Holdings $255.6 million Term Loan. LNG Holdings has entered into interest rate swap agreements that effectively fixed the interest rate applicable to the 2012 Term Loan at 4.98 percent plus a credit spread of 0.625, based upon PEPL's credit rating for its senior unsecured debt. See *Item 8. Financial Statements and Supplementary Data, Note 11 – Derivative Instruments and Hedging Activities – Interest Rate Swaps* for information regarding interest rate swaps on the 2012 Term Loan.

In connection with the December 1, 2006 closing of the Redemption Agreement, LNG Holdings, as borrower, and PEPL and CrossCountry Citrus, LLC, as guarantors, entered into the $465 million 2006 Term Loan due April 4, 2008. On June 29, 2007, the parties entered into an amended and restated term loan facility (*Amended Credit Agreement*). The Amended Credit Agreement extended the maturity of the term loan from April 4, 2008 to June 29, 2012, and decreased the interest rate from LIBOR plus 87.5 basis points to LIBOR plus 55 basis points, based upon the current credit rating of PEPL's senior unsecured debt. The balance of the term loan facility at December 31, 2007 was $412.2 million.

Junior Subordinated Notes. On October 23, 2006, the Company issued $600 million in Junior Subordinated Notes due November 1, 2066 with an initial fixed interest rate of 7.20 percent. In connection with the issuance of the Junior Subordinated Notes, the Company incurred underwriting and discount costs of approximately $9 million. The debt was priced to the public at 99.844 percent, resulting in $590.1 million in proceeds to the Company. The outstanding balance of $525 million on the Sid Richardson Bridge Loan discussed below was retired using the proceeds from the debt offering and the remaining approximately $65 million of debt offering proceeds were used to pay down a portion of the Company's credit facilities. See related information in *Item 8. Financial Statements and Supplementary Data, Note 13 – Debt Obligations – Long-Term Debt – Junior Subordinated Notes*.

Short-Term Debt Obligations, Excluding Current Portion of Long-Term Debt.

Credit Facilities. On September 29, 2005, the Company entered into a Fourth Amended and Restated Revolving Credit Facility in the amount of $400 million (*Long-Term Facility*). The Long-Term Facility has a five-year term and matures on May 28, 2010. The Long-Term Facility replaced the Company's May 28, 2004 long-term credit facility in the same amount. Borrowings under the Long-Term Facility are available for Southern Union's working capital and letter of credit requirements and other general corporate purposes. The Long-Term Facility is subject to a commitment fee based on the rating of the Company's senior unsecured notes (*Senior Notes*). As of December 31, 2007, the commitment fees were an annualized 0.15 percent. The Company has an additional $30 million of availability under uncommitted lines of credit facilities with various banks.

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Balances of $123 million and $100 million were outstanding under the Company's credit facilities at effective interest rates of 5.82 percent and 6.02 percent at December 31, 2007 and December 31, 2006, respectively. The Company classifies its borrowings under the credit facilities due May 28, 2010 as short-term debt, as the individual borrowings are generally for periods of 15 to 180 days. At maturity, the Company may (i) retire the outstanding balance of each borrowing with available cash on hand and/or proceeds from a new borrowing, or (ii) at the Company's option, extend the borrowing's maturity date for up to an additional 90 days. As of February 22, 2008, there was a balance of $45 million outstanding under the Company's credit facilities at an average effective interest rate of 3.77 percent.

Sid Richardson Bridge Loan. On March 1, 2006, Southern Union acquired SUGS for $1.6 billion in cash. The acquisition was funded by a bridge loan facility in the amount of $1.6 billion that was entered into on March 1, 2006 between the Company and a group of banks as lenders. On August 24, 2006, the Company applied approximately $1.1 billion in net proceeds from the sales of the assets of its PG Energy natural gas distribution division and the Rhode Island operations of its New England Gas Company natural gas distribution division to repayment of the Sid Richardson Bridge Loan. On October 23, 2006, the Company retired the remainder of the Sid Richardson Bridge Loan using a portion of the $590.1 million in proceeds received from the $600 million Junior Subordinated Notes offering discussed above.

Interest expense totaling $49.2 million related to the Sid Richardson Bridge Loan was incurred during 2006 at an average interest rate of 5.72 percent. Debt issuance costs totaling $9.2 million were incurred in connection with the financing of the acquisition, of which $7.8 million was related to the Sid Richardson Bridge Loan and $1.4 million was related to the placement of permanent financing. The Company fully amortized the $7.8 million of the Sid Richardson Bridge Loan debt issuance cost to interest expense during 2006.

Expected Refinancing and Other Debt Matters

Expected Refinancing. The Company plans to refinance its $425 million of debt maturing in August 2008 with new capital market debt or bank financings. Alternatively, should the Company not be successful in its refinancing efforts, the Company may choose to retire such debt upon maturity by utilizing some combination of cash flows from operations, draw downs under existing credit facilities, and altering the timing of controllable expenditures, among other things. The Company believes, based on its investment grade credit ratings and general financial condition, successful historical access to capital and debt markets, current economic and capital market conditions and market expectations regarding the Company's future earnings and cash flows, that it will be able to refinance and/or retire these obligations under acceptable terms prior to their maturity. There can be no assurance, however, that the Company will be able to achieve acceptable refinancing terms in any negotiation of new capital market debt or bank financings. Moreover, there can be no assurance the Company will be successful in its implementation of these refinancing and/or retirement plans and the Company's inability to do so would cause a material adverse effect on the Company's financial condition and liquidity.

Credit Ratings. As of December 31, 2007, both Southern Union's and Panhandle's debt are rated Baa3 by Moody's Investor Services, Inc., BBB- by Standard & Poor's and BBB by Fitch Ratings. If its current credit ratings are downgraded below investment grade or if there are times when it is placed on "credit watch," both borrowing costs and the costs of maintaining certain contractual relationships could increase. Lower credit ratings could also adversely affect relationships with state regulators, who may be unwilling to allow the Company to pass along increased debt service costs to natural gas customers.

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OTHER MATTERS

Master Limited Partnership

On November 9, 2007, the Company announced its intention to pursue an initial public offering of units representing limited partner interests of a master limited partnership (*MLP*) to be formed by the Company to hold a portion of the gathering and processing assets of its SUGS business. In light of recent unfavorable conditions in the MLP market, including the delay or cancellation of other previously announced initial public offerings, the Company has determined to postpone filing of a registration statement until such time as market conditions improve.

This Annual Report on Form 10-K shall not constitute an offer to sell or the solicitation of an offer to buy any securities. Any offers, solicitations of offers to buy, or any sales of securities will only be made in accordance with the registration requirements of the Securities Act of 1933 or an exemption therefrom.

Off-Balance Sheet Arrangements and Aggregate Contractual Obligations

The following table summarizes the Company's expected contractual obligations by payment due date as of December 31, 2007:

	Contractual Obligations (In thousands)						
	Total	**2008**	**2009**	**2010**	**2011**	**2012**	**2013 and thereafter**
Long-term debt (1), (2)	$ 3,388,913	$ 434,831	$ 60,623	$ 140,500	$ -	$ 857,389	$ 1,895,570
Short-term borrowing, including credit facilities (1)	123,000	123,000	-	-	-	-	-
Gas purchases (3)	618,822	244,103	209,202	165,517	-	-	-
Missouri Gas Energy Safety Program	141,324	12,991	12,633	12,760	12,887	10,868	79,185
Transportation contracts	310,987	74,786	70,732	55,815	44,664	11,819	53,171
Storage contracts (4)	175,169	32,273	24,242	18,720	17,250	14,302	68,382
Operating lease payments	143,903	16,423	19,236	18,294	18,230	13,929	57,791
Interest payments on debt (5), (6)	4,196,668	213,424	190,243	184,631	182,961	151,448	3,273,961
Benefit plan contributions	24,314	24,314	-	-	-	-	-
Other (7)	4,116	1,690	980	872	389	185	-
Total contractual cash obligations	$ 9,127,216	$ 1,177,835	$ 587,891	$ 597,109	$ 276,381	$ 1,059,940	$ 5,428,060

(1) The Company is party to debt agreements containing certain covenants that, if not satisfied, would give rise to an event of default that would cause such debt to become immediately due and payable. Such covenants require the Company to maintain a certain level of net worth, to meet certain debt to total capitalization ratios, and to meet certain ratios of earnings before depreciation, interest and taxes to cash interest expense. At December 31, 2007, the Company was in compliance with all of its covenants. See *Item 8. Financial Statements and Supplementary Data, Note 13 – Debt Obligations*.
(2) The long-term debt principal payment obligations exclude $6.1 million of unamortized debt premium as of December 31, 2007.
(3) The Company has purchase gas tariffs in effect for all its utility service areas that provide for recovery of its purchased gas costs under defined methodologies.
(4) Represents charges for third party storage capacity.
(5) Interest payments on debt are based upon the applicable stated or variable interest rates as of December 31, 2007. Includes approximately $2.5 billion of interest payments associated with the $600 million Junior Subordinated Notes due November 1, 2066.
(6) Excludes interest on the $100 million 6.089% Senior Notes due February 16, 2010 entered into on February 19, 2008. See *Item 8. Financial Statements and Supplementary Data, Note 25 – Subsequent Event.*
(7) Includes FIN 48 unrecognized tax benefits and various other contractual obligations.

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Contingencies

See *Item 8. Financial Statements and Supplementary Data, Note 18 – Commitments and Contingencies*.

Inflation

The Company believes that inflation has caused, and will continue to cause, increases in certain operating expenses and has required, and will continue to require, it to replace assets at higher costs. The Company continually reviews the adequacy of its rates in relation to the impact of market conditions, the increasing cost of providing services and the inherent regulatory lag experienced in the Transportation and Storage and Distribution segments in adjusting those rates.

Regulatory

See *Item 8. Financial Statements and Supplementary Data, Note 16 – Regulation and Rates*.

Critical Accounting Policies

Summary

The Company's consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America. The preparation of these financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and related disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Estimates and assumptions about future events and their effects cannot be determined with certainty. On an ongoing basis, the Company evaluates its estimates based on historical experience, current market conditions and on various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying value of assets and liabilities that are not readily apparent from other sources. Nevertheless, actual results may differ from these estimates under different assumptions or conditions. The following is a summary of the Company's most critical accounting policies, which are defined as those policies whereby judgments or uncertainties could affect the application of those policies and materially different amounts could be reported under different conditions or using different assumptions. For a summary of all of the Company's significant accounting policies, see *Item 8. Financial Statements and Supplementary Data, Note 2 – Summary of Significant Accounting Policies.*

Effects of Regulation

The Company is subject to regulation by certain state and federal authorities in each of its reportable segments and for certain of its operations reported as discontinued operations. Missouri Gas Energy, New England Gas Company and Florida Gas have accounting policies that conform to FASB Statement No. 71, *Accounting for the Effects of Certain Types of Regulation (Statement No. 71)*, and which are in accordance with the accounting requirements and ratemaking practices of the applicable regulatory authorities. The application of these accounting policies allows the Company to defer expenses and revenues on the balance sheet as regulatory assets and liabilities when it is probable that those expenses and revenues will be allowed in the ratemaking process in a period different from the period in which they would have been reflected in the Consolidated Statement of Operations by an unregulated company. These deferred assets and liabilities then flow through the results of operations in the period in which the same amounts are included in rates and recovered from or refunded to customers. Management's assessment of the probability of recovery or pass through of regulatory assets and liabilities requires judgment and interpretation of laws and regulatory commission orders. If, for any reason, the Company ceases to meet the criteria for application of regulatory accounting treatment for all or part of its operations, the regulatory assets and liabilities related to those portions ceasing to meet such criteria would be eliminated from the Consolidated Balance Sheet and included in the Consolidated Statement of Operations for the period in which the discontinuance of regulatory accounting treatment occurs. The aggregate amount of regulatory assets reflected in the Consolidated Balance Sheet applicable to the Distribution segment are $64.2 million and $65.9 million at December 31, 2007 and 2006, respectively. The aggregate amount of regulatory liabilities reflected in the Consolidated Balance Sheet applicable to the Distribution segment are $6.5 million and $8.9 million at December 31, 2007 and 2006, respectively. For a summary of regulatory matters applicable to the

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Company, see *Item 8. Financial Statements and Supplementary Data, Note 16 – Regulation and Rates*. Panhandle and SUGS do not currently apply Statement No. 71.

Long-Lived Assets

Long-lived assets, including property, plant and equipment and goodwill, comprise a significant amount of the Company's total assets. The Company makes judgments and estimates about the carrying value of these assets, including amounts to be capitalized, depreciation methods and useful lives. The Company also reviews these assets for impairment on a periodic basis or whenever events or changes in circumstances indicate that the carrying amounts may not be recoverable. The impairment test consists of a comparison of an asset's fair value with its carrying value; if the carrying value of the asset exceeds its fair value, an impairment loss is recognized in the Consolidated Statement of Operations in an amount equal to that excess. When an asset's fair value is not readily apparent from other sources, management's determination of an asset's fair value requires it to make long-term forecasts of future net cash flows related to the asset. These forecasts require assumptions about future demand, future market conditions and regulatory developments. Significant and unanticipated changes to these assumptions could require a provision for impairment in a future period.

The Company assesses its goodwill for impairment at least annually based on FASB Statement 142, *Goodwill and Other Intangible Assets*. An initial assessment is made by comparing the fair value of the operations with goodwill, as determined in accordance with Statement 142, to the book value of each reporting unit. If the fair value is less than the book value, an impairment is indicated, and a second test is performed to measure the amount of the impairment. In the second test, the implied fair value of the goodwill is calculated by deducting the fair value of all tangible and intangible net assets of the operations with goodwill from the fair value determined in step one of the assessment. If the carrying value of the goodwill exceeds this calculated implied fair value of the goodwill, an impairment charge is recorded. As of November 30, 2007, the Company evaluated goodwill for impairment and no impairment was indicated. Execution of agreements for the sale of the Company's PG Energy natural gas distribution division and the Rhode Island operations of its New England Gas Company natural gas distribution division in the first quarter of 2006 constituted a subsequent event of the type that under generally accepted accounting principles in the United States of America required the Company to consider the fair value indicated by the definitive sale agreements in its 2005 goodwill impairment evaluation. Based on the purchase prices reflected in the definitive agreements, the Company reported a $175 million goodwill impairment in the fourth quarter of 2005.

Purchase Accounting

The Company's acquisition of Sid Richardson Energy Services was accounted for using the purchase method of accounting in accordance with FASB Statement No. 141, *Business Combinations*. CCE Holdings, a joint venture in which Southern Union owned a 50 percent equity interest until it became a wholly-owned subsidiary on December 1, 2006 in conjunction with the closing of the Redemption Agreement, also applied the purchase method of accounting for its acquisition of CrossCountry Energy on November 17, 2004. Under this statement, the purchase price paid by the acquirer, including transaction costs, is allocated to the net assets acquired as of the acquisition date based on their fair value. Determining the fair value of certain assets acquired and liabilities assumed is judgmental in nature and often involves the use of significant estimates and assumptions. Southern Union has generally used outside appraisers to assist in the initial determination of fair value. The appraisals related to Southern Union's acquisition of CCE Holdings and Sid Richardson Energy Services were finalized in 2005 and 2006, respectively.

Southern Union effectively acquired an additional 25 percent interest in Citrus on December 1, 2006 as a result of the transactions described in *Item 8. Financial Statements and Supplementary Data, Note 3 – Acquisitions and Sales – CCE Holdings Transactions*. The purchase price allocation associated with this incremental equity investment in Citrus is accounted for under Accounting Principles Board Opinion 18, *The Equity Method of Accounting for Investments in Common Stock*. For additional information, see *Item 8. Financial Statements and Supplementary Data, Note 9 – Unconsolidated Investments – CCE Holdings Goodwill Evaluation*.

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Pensions and Other Postretirement Benefits

Effective December 31, 2006, the Company adopted the recognition and disclosure provisions of FASB Statement No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans – an amendment of FASB Statements No. 87, 88, 106 and 132(R)* (*Statement No. 158*). Statement No. 158 does not amend the expense recognition provisions of Statements No. 87, 88 and 106, but requires employers to recognize in their balance sheets the overfunded or underfunded status of defined benefit postretirement plans, measured as the difference between the fair value of the plan assets and the benefit obligation (the projected benefit obligation for pension plans and the accumulated postretirement benefit obligation for other postretirement plans). Each overfunded plan is recognized as an asset and each underfunded plan is recognized as a liability. Employers must recognize the change in the funded status of the plan in the year in which the change occurs through *Accumulated other comprehensive loss* in stockholders' equity. Effective for years ending after December 15, 2008 (with early adoption permitted), Statement No. 158 also requires plan assets and benefit obligations to be measured as of the employers' balance sheet date. The Company has not yet adopted the measurement date provisions of Statement No. 158.

The Company accounted for the measurement of its defined benefit postretirement plans under Statement No. 87, *Employers Accounting for Pensions* (*Statement No. 87*) and Statement No. 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions* (*Statement No. 106*). Prior to the adoption of the recognition and disclosure provisions of Statement No. 158, Statement No. 87 required that a liability (minimum pension liability) be recorded when the accumulated benefit obligation liability exceeded the fair value of plan assets. Any adjustment was recorded as a non-cash charge to *Accumulated other comprehensive loss*. Statement No. 106 had no minimum liability provision. Under both Statements No. 87 and 106, changes in the funded status were not immediately recognized, rather they were deferred and recognized ratably over future periods. Upon adoption of the recognition provisions of Statement No. 158, the Company recognized the amounts of these prior changes in the funded status of its defined benefit postretirement plans through *Accumulated other comprehensive loss*.

The calculation of the Company's pension expense and projected benefit obligation requires the use of a number of assumptions. Changes in these assumptions can have a significant effect on the amounts reported in the financial statements. The Company believes that the two most critical assumptions are the assumed discount rate and the expected rate of return on plan assets.

The Company establishes the discount rate using the Citigroup Pension Discount Curve as published on the Society of Actuaries website as the hypothetical portfolio of high-quality debt instruments that would provide the necessary cash flows to pay the benefits when due. Pension expense and projected benefit obligation (*PBO*) increases and equity decreases as the discount rate is reduced. Lowering the discount rate assumption by 0.5 percent would increase the Company's 2007 pension expense and PBO at the end of 2007 by $400,000 and $13.1 million, respectively, and would decrease equity at the end of 2007 by $8.1 million.

The expected rate of return on plan assets is based on long-term expectations given current investment objectives and historical results. Pension expense increases as the expected rate of return on plan assets is reduced. Lowering the expected rate of return on plan assets assumption by 0.5 percent would increase the Company's 2007 pension expense by $550,000.

See *Item 8. Financial Statements and Supplementary Data, Note 14 – Benefits* for additional related information.

Derivatives and Hedging Activities

The Company follows FASB Statement No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended, to account for derivative and hedging activities. In accordance with this statement all derivatives are recognized on the balance sheet at their fair value. On the date the derivative contract is entered into, the Company designates the derivative as: (i) a hedge of the fair value of a recognized asset or liability or of an unrecognized firm commitment (fair value hedge); (ii) a hedge of a forecasted transaction or the variability of cash flows to be received or paid in conjunction with a recognized asset or liability (cash flow hedge); or (iii) an instrument that is held for trading or non-hedging purposes (a trading or economic hedging instrument). For derivatives treated as a fair value hedge, the effective portion of changes in fair value are recorded as an adjustment to the hedged item. The ineffective portion of a fair value hedge is recognized in earnings if the short cut method of assessing effectiveness is not used. Upon termination of a fair value hedge of a debt instrument, the resulting

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gain or loss is amortized to earnings through the maturity date of the debt instrument. For derivatives treated as a cash flow hedge, the effective portion of changes in fair value is recorded in *Accumulated other comprehensive loss* until the related hedged items impact earnings. Any ineffective portion of a cash flow hedge is reported in current-period earnings. For derivatives treated as trading or economic hedging instruments, changes in fair value are reported in current-period earnings. Fair value is determined based upon quoted market prices and mathematical models using current and historical data.

The Company formally assesses, both at the hedge's inception and on an ongoing basis, whether the derivatives that are used in hedging transactions have been highly effective in offsetting changes in the fair value or cash flows of hedged items and whether those derivatives may be expected to remain highly effective in future periods. The Company discontinues hedge accounting when: (i) it determines that the derivative is no longer effective in offsetting changes in the fair value or cash flows of a hedged item; (ii) the derivative expires or is sold, terminated, or exercised; (iii) it is no longer probable that the forecasted transaction will occur; or (iv) management determines that designating the derivative as a hedging instrument is no longer appropriate. In all situations in which hedge accounting is discontinued and the derivative remains outstanding, the Company will carry the derivative at its fair value on the balance sheet, recognizing changes in the fair value in current-period earnings. See *Item 8. Financial Statements and Supplementary Data, Note 11 – Derivative Instruments and Hedging Activities*.

Commitments and Contingencies

The Company is subject to proceedings, lawsuits and other claims related to environmental and other matters. Accounting for contingencies requires significant judgments by management regarding the estimated probabilities and ranges of exposure to potential liability. For further discussion of the Company's commitments and contingencies, see *Item 8. Financial Statements and Supplementary Data, Note 18 – Commitments and Contingencies.*

New Accounting Pronouncements

See *Item 8. Financial Statements and Supplementary Data, Note 2 – Summary of Significant Accounting Policies – New Accounting Principles*.

ITEM 7A. Quantitative and Qualitative Disclosures About Market Risk.

Interest Rate Risk

The Company is subject to the risk of loss associated with movements in market interest rates. The Company manages this risk through the use of fixed-rate debt, floating-rate debt and interest rate swaps. Fixed-rate swaps are used to reduce the risk of increased interest costs during periods of rising interest rates. Floating-rate swaps are used to convert the fixed rates of long-term borrowings into short-term variable rates. At December 31, 2007, the interest rate on 88 percent of the Company's long-term debt was fixed after considering the impact of interest rate swaps.

At December 31, 2007, $17.1 million is included in *Deferred Credits* in the Consolidated Balance Sheet related to the fixed-rate interest rate swaps on the $455 million Term Loan due 2012.

At December 31, 2007, a 100 basis point move in the annual interest rate on all outstanding floating-rate long-term debt would increase the Company's interest payments by approximately $434,000 for each month during which such increase continued. If interest rates changed significantly, the Company would take actions to manage its exposure to the change. No change has been assumed, as a specific action and the possible effects are uncertain.

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The Company also enters into treasury rate locks to manage its exposure against changes in future interest payments attributable to changes in the US treasury rates. By entering into these agreements, the Company locks in an agreed upon interest rate until the settlement of the contract. The Company accounts for the treasury rate locks as cash flow hedges. At December 31, 2007, $1.7 million is included in *Prepayments and Other* in the Consolidated Balance Sheet related to the treasury rate locks. The Company has treasury rate locks with an aggregate notional amount of $375 million outstanding as of December 31, 2007 to hedge the changes in cash flows of anticipated interest payments from changes in treasury rates prior to the issuance of new debt instruments.

The change in exposure to loss in earnings and cash flow related to interest rate risk for the year ended December 31, 2007 is not material to the Company.

See *Item 8. Financial Statements and Supplementary Data*, *Note 11 – Derivative Instruments and Hedging Activities* and *Note 13 - Debt Obligations*.

Commodity Price Risk

Gathering and Processing Segment. The Company markets natural gas and NGLs in its Gathering and Processing segment and manages associated commodity price risks using both economic and accounting hedge derivative financial instruments. These instruments involve not only the risk of transacting with counterparties and their ability to meet the terms of the contracts but also the risk associated with unmatched positions and market fluctuations. The Company is required to record its commodity derivative financial instruments at fair value, which is determined by commodity exchange prices, over-the-counter quotes, volatility, time value, counterparty credit and the potential impact on market prices of liquidating positions in an orderly manner over a reasonable period of time under current market conditions.

To manage its commodity price risk related to natural gas and NGLs, the Company uses a combination of crude oil puts, NGL gross processing spread puts, fixed-price physical forward sales contracts, exchange-traded futures and options, and fixed or floating index and basis swaps to manage commodity price risk. These derivative financial instruments allow the Company to preserve value and protect margins because changes in the value of the derivative financial instruments are highly effective in offsetting changes in the physical market and reducing basis risk. Basis risk exists primarily due to price differentials between cash market delivery locations and futures contract delivery locations. At December 31, 2007, the net asset derivative balance of the Company's economic hedging derivatives in the Gathering and Processing segment was $6.7 million. All previous accounting hedges designated as cash flow hedges in the Gathering and Processing segment expired at December 31, 2007.

The Company realizes NGL and/or natural gas volumes from its contractual arrangements associated with gas processing services it provides. The Company utilizes various economic hedge techniques to manage its price exposure of Company owned volumes, including processing spread puts and natural gas swaps. Expected NGL and/or natural gas volumes compared to the actual volumes sold and the effectiveness of the associated economic hedges utilized by the Company can be unfavorably impacted by:

- Processing plant outages;
- Higher than anticipated FF&U efficiency levels;
- Impact of commodity prices in general;
- Lower than expected recovery of NGLs from the residue gas stream; and
- Lower than expected recovery of natural gas volumes to be processed.

For the purpose of reducing its processing spread exposure, the Company purchased put options for the period February 1, 2008 through December 31, 2008. The put options reduce its processing spread exposure on 11,075 MMBtu/day, or approximately 25 percent of the Company's expected NGLs sales volumes based on 2007 historical processing trends. The put options set a floor for the Company's processing spread at $8.15 per MMBtu for such volumes. The cost of the December 2007 transaction was $5.2 million, or $1.41 per MMBtu.

Additionally, in February 2008, for the period March 1, 2008 through December 31, 2008, the Company entered into various natural gas swaps which have reduced its commodity price exposure related to 30,000 MMBtu/day. The natural gas swaps have effectively established an average fixed index price at locations where we sell natural gas, at the "basis adjusted price" of $8.28 per MMBtu for the related period. The combination of the processing spread put option with an equal MMBtu portion of the natural gas swap effectively establishes a floor of $15.02 per MMBtu for 25 percent of the Company's expected NGL sales volumes as noted above. In February 2008, the Company also entered into natural gas swaps associated with 10,000 MMBtu/day for the period January 1, 2009 through December 31, 2009, fixing the 2009 basis adjusted sales price of such volumes at $8.19 per MMBtu.

For further information related to SUGS' commodity-based put options and non-heding derivative instruments, see *Item 8. Financial Statements and Supplementary Data, Note 11 – Derivative Instruments and Hedging Activities – Gathering and Processing Segment*.

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Transportation and Storage Segment. The Company is exposed to commodity price risk as its interstate pipelines collect natural gas from its customers for operations or as part of their fee for services provided. When the amount of natural gas utilized in operations by these pipelines differs from the amount provided by their customers, the pipelines may use natural gas from inventory or could have to buy or sell natural gas to cover these operational needs, and thus have some exposure to commodity price risk. At December 31, 2007, there were no hedges in place in respect to natural gas price risk from its interstate pipeline operations.

Distribution Segment Economic Hedging Activities. During 2007, 2006 and 2005, the Company entered into natural gas commodity swaps and collars to mitigate price volatility of natural gas passed through to utility customers in the Distribution segment. The cost of the derivative products and the settlement of the respective obligations are recorded through the gas purchase adjustment clause as authorized by the applicable regulatory authority and therefore do not impact earnings. The fair values of the contracts are recorded as an adjustment to a regulatory asset or liability in the Consolidated Balance Sheet. As of December 31, 2007, the fair values of the contracts, which expire at various times through December 2009, are included in the Consolidated Balance Sheet as assets and liabilities, respectively, with matching adjustments to deferred cost of gas of $22.3 million.

ITEM 8. Financial Statements and Supplementary Data.

The information required here is included in the report as set forth in the *Index to Consolidated Financial Statements* on page F-1.

ITEM 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.

None.

ITEM 9A. Controls and Procedures.

EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

Southern Union has established disclosure controls and procedures to ensure that information required to be disclosed by the Company, including consolidated entities, in reports filed or submitted under the Securities Exchange Act of 1934, as amended (*Exchange Act*), is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. The Company's disclosure controls and procedures are designed to ensure that information required to be disclosed in the reports it files or submits under the Exchange Act is accumulated and communicated to management, including the Company's Chief Executive Officer (*CEO*) and Chief Financial Officer (*CFO*), as appropriate, to allow timely decisions regarding required disclosure. The Company performed an evaluation under the supervision and with the participation of management, including its CEO and CFO, and with the participation of personnel from its Legal, Internal Audit, Risk Management and Financial Reporting Departments, of the effectiveness of the design and operation of the Company's disclosure controls and procedures (as defined in Exchange Act Rule 13a-15(e)) as of the end of the period covered by this report. Based on the evaluation, Southern Union's CEO and CFO concluded that the Company's disclosure controls and procedures were effective as of December 31, 2007.

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MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The Company's management is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is defined in Exchange Act Rule 13a-15(f) as a process designed by, or under the supervision of, the Company's principal executive officer and principal financial officers, or persons performing similar functions, and effected by the Company's board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles, and includes those policies and procedures that:

- Provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company;
- Pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the Company; and
- Provide reasonable assurance regarding the prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the financial statements.

Exchange Act Rules 13a-15(c) and 15d-15(c) and Section 404 of the Sarbanes-Oxley Act of 2002 require management of the Company to conduct an annual evaluation of the Company's internal control over financial reporting and to provide a report on management's assessment, including a statement as to whether or not internal control over financial reporting is effective.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management's evaluation of the effectiveness of the Company's internal control over financial reporting was based on the framework in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (*COSO*). Based on its evaluation under that framework and applicable SEC rules, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2007.

The Company's internal control over financial reporting as of December 31, 2007 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report, which is included herein.

Southern Union Company
February 29, 2008

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is not aware of any change in Southern Union's internal control over financial reporting that occurred during the quarter ended December 31, 2007 that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

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ITEM 9B. Other Information.

All information required to be reported on Form 8-K for the quarter ended December 31, 2007 was appropriately reported.

PART III

ITEM 10. Directors, Executive Officers and Corporate Governance.

There is incorporated in this Item 10 by reference the information that will appear in the Company's definitive proxy statement for the 2008 Annual Meeting of Stockholders under the captions *Meetings and Committees of the Board – Board of Directors, 2007 Executive Compensation – Named Executive Officers, Section 16(a) Beneficial Ownership Reporting Compliance, Corporate Governance – Code of Ethics, Meetings and Committees of the Board – Board Committees – Corporate Governance Committee* and – *Audit Committee*.

The Company has adopted a Code that applies to its CEO, CFO, Controller and other individuals in the finance department performing similar functions. The Code is available on the Company's website at www.sug.com. If any substantive amendment to the Code is made or any waiver is granted thereunder, including any implicit waiver, the Company's CEO, CFO or other authorized officer will disclose the nature of such amendment or waiver on the website at www.sug.com or in a Current Report on Form 8-K.

The CEO Certification and Annual Written Affirmation required by the NYSE Listing Standards, Section 303A.12(a), relating to the Company's compliance with the NYSE Corporate Governance Listing Standards, was submitted to the NYSE on May 25, 2007.

ITEM 11. Executive Compensation.

There is incorporated in this Item 11 by reference the information that will appear in the Company's definitive proxy statement for the 2008 Annual Meeting of Stockholders under the captions *Compensation Discussion and Analysis, 2007 Executive Compensation - Summary Compensation Table - Grants of Plan-Based Awards - Outstanding Equity Awards at December 31, 2007 - Option Exercises and Stock Vested - Non-Qualified Deferred Compensation* and - *Potential Payments Upon Termination or Change of Control,* and *2007 Director Compensation,* and *Meetings and Committees of the Board – Board Committees – Compensation Committee*.

ITEM 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.

There is incorporated in this Item 12 by reference the information that will appear in the Company's definitive proxy statement for the 2008 Annual Meeting of Stockholders under the captions *Security Ownership of Certain Beneficial Owners and Management*.

ITEM 13. Certain Relationships and Related Transactions, and Director Independence.

There is incorporated in this Item 13 by reference the information that will appear in the Company's definitive proxy statement for the 2008 Annual Meeting of Stockholders under the caption *Corporate Governance – Transactions with Related Persons* and – *Review, Approval or Ratification of Transactions with Related Persons,* and *Corporate Governance – Director Independence* and – *Independent Director Chairman*.

ITEM 14. Principal Accounting Fees and Services.

There is incorporated in this Item 14 by reference the information that will appear in the Company's definitive proxy statement for the 2008 Annual Meeting of Stockholders under the caption *Meetings and Committees of the Board – Board Committees and Meetings – Audit Committee*.

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PART IV

ITEM 15. Exhibits, Financial Statement Schedules.

(a)(1) and (2) **Financial Statements and Financial Statement Schedules.**

(a)(3) **Exhibits.**

Exhibit No.	Description
2(a)	Purchase and Sale Agreement by and among SRCG, Ltd. and SRG Genpar, L.P., as Sellers and Southern Union Panhandle LLC and Southern Union Gathering Company LLC, as Buyers, dated as of December 15, 2005. (Filed as Exhibit 10.1 to Southern Union's Current Report on Form 8-K filed on December 16, 2005 and incorporated herein by reference.)
2(b)	Purchase and Sale Agreement between Southern Union Company and UGI Corporation, dated as of January 26, 2006. (Filed as Exhibit 10.1 to Southern Union's Current Report on Form 8-K filed on January 30, 2006 and incorporated herein by reference.)
2(c)	First Amendment to the Purchase and Sale Agreement between Southern Union Company and UGI Corporation, dated as of August 24, 2006. (Filed as Exhibit 10.1 to Southern Union's Current Report on Form 8-K filed on August 30, 2006 and incorporated herein by reference.)
2(d)	Purchase and Sale Agreement between Southern Union Company and National Grid USA, dated as of February 15, 2006. (Filed as Exhibit 10.1 to Southern Union's Current Report on Form 8-K filed on February 17, 2006 and incorporated herein by reference.)
2(e)	Limited Settlement Agreement between Southern Union Company, Narragansett Electric Company d/b/a National Grid, the Department of the Attorney General for the State of Rhode Island and the Rhode Island Department of Environmental Management, dated as of August 24, 2006. (Filed as Exhibit 10.2 to Southern Union's Current Report on Form 8-K filed on August 30, 2006 and incorporated herein by reference.)
2(f)	First Amendment to the Purchase and Sale Agreement between Southern Union Company and National Grid USA, dated as of August 24, 2006. (Filed as Exhibit 10.3 to Southern Union's Current Report on Form 8-K filed on August 30, 2006 and incorporated herein by reference.)
2(g)	Redemption Agreement by and between CCE Holdings, LLC and Energy Transfer Partners, L.P., dated as of September 18, 2006. (Filed as Exhibit 10.1 to Southern Union's Current Report on Form 8-K filed on September 18, 2006 and incorporated herein by reference.)
2(h)	Letter Agreement by and between Southern Union Company and Energy Transfer Partners, L.P., dated as of September 14, 2006. (Filed as Exhibit 10.2 to Southern Union's Current Report on Form 8-K filed on September 18, 2006 and incorporated herein by reference)
3(a)	Amended and Restated Certificate of Incorporation of Southern Union Company. (Filed as Exhibit 3(a) to Southern Union's Annual Report on Form 10-K filed on March 16, 2006 and incorporated herein by reference.)
3(b)	By-Laws of Southern Union Company, as amended through January 3, 2007. (Filed as Exhibit 3.1 to Southern Union's Current Report on Form 8-K filed on January 3, 2007 and incorporated herein by reference.)
3(c)	Certificate of Designations, Preferences and Rights re: Southern Union Company's 7.55% Noncumulative Preferred Stock, Series A. (Filed as Exhibit 4.1 to Southern Union's Form 8-A/A dated October 17, 2003 and incorporated herein by reference.)

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4(a) Specimen Common Stock Certificate. (Filed as Exhibit 4(a) to Southern Union's Annual Report on Form 10-K for the year ended December 31, 1989 and incorporated herein by reference.)

4(b) Indenture between The Bank of New York Trust Company, N.A., as successor to Chase Manhattan Bank, N.A., as trustee, and Southern Union Company dated January 31, 1994. (Filed as Exhibit 4.1 to Southern Union's Current Report on Form 8-K dated February 15, 1994 and incorporated herein by reference.)

4(c) Officers' Certificate dated January 31, 1994 setting forth the terms of the 7.60% Senior Debt Securities due 2024. (Filed as Exhibit 4.2 to Southern Union's Current Report on Form 8-K dated February 15, 1994 and incorporated herein by reference.)

4(d) Officer's Certificate of Southern Union Company dated November 3, 1999 with respect to 8.25% Senior Notes due 2029. (Filed as Exhibit 99.1 to Southern Union's Current Report on Form 8-K filed on November 19, 1999 and incorporated herein by reference.)

4(e) Form of Supplemental Indenture No. 1, dated June 11, 2003, between Southern Union Company and The Bank of New York Trust Company, N.A., as successor to JP Morgan Chase Bank (formerly the Chase Manhattan Bank, National Association). (Filed as Exhibit 4.5 to Southern Union’s Form 8-A/A dated June 20, 2003 and incorporated herein by reference.)

4(f) Supplemental Indenture No. 2, dated February 11, 2005, between Southern Union Company and The Bank of New York Trust Company, N.A., as successor to JP Morgan Chase Bank, N.A. (f/n/a JP Morgan Chase Bank). (Filed as Exhibit 4.4 to Southern Union’s Form 8-A/A dated February 22, 2005 and incorporated herein by reference.)

4(g) Subordinated Debt Securities Indenture between Southern Union Company and The Bank of New York Trust Company, N.A., as successor to JP Morgan Chase Bank (as successor to The Chase Manhattan Bank, N.A.), as Trustee. (Filed as Exhibit 4-G to Southern Union’s Registration Statement on Form S-3 (No. 33-58297) and incorporated herein by reference.)

4(h) Second Supplemental Indenture, dated October 23, 2006, between Southern Union Company and The Bank of New York Trust Company, N.A., successor to JP Morgan Chase Bank, N.A., formerly known as JPMorgan Chase Bank, formerly known as The Chase Manhattan Bank (National Association). (Filed as Exhibit 4.1 to Southern Union’s Form 8-K/A dated October 24, 2006 and incorporated herein by reference.)

4(i) 2006 Series A Junior Subordinated Notes Due November 1, 2066 dated October 23, 2006 (Filed as Exhibit 4.2 to Southern Unions Current Report on Form 8-K/A filed on October 24, 2006 and incorporated herein by reference.)

4(j) Replacement Capital Covenant, dated as of October 23, 2006 by Southern Union Company, a Delaware corporation with its successors and assigns, in favor of and for the benefit of each Covered Debtor (as defined in the Covenant). (Filed as Exhibit 4.3 to Southern Union’s Current Report on Form 8-K/A filed on October 24, 2006 and incorporated herein by reference.)

4(k) Southern Union is a party to other debt instruments, none of which authorizes the issuance of debt securities in an amount which exceeds 10% of the total assets of Southern Union. Southern Union hereby agrees to furnish a copy of any of these instruments to the Commission upon request.

10(a) Construction and Term Loan Agreement between Citrus Corp., as borrower, and Pipeline Funding Company, LLC, as lender and administrative agent, dated as of February 5, 2008. (Filed as Exhibit 10.1 to Southern Union’s Current Report on Form 8-K filed on February 8, 2008 and incorporated herein by reference.)

10(b) Amended and Restated Credit Agreement between Trunkline LNG Holdings, LLC, as borrower, Panhandle Eastern Pipeline Company, LP and CrossCountry Citrus, LLC, as guarantors, the financial institutions listed therein Bayerische Hypo-Und Vereinsbank AG, New York Branch, as administrative

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agent, dated as of June 29, 2007. (Filed as Exhibit 10.1 to Southern Union's Current Report on Form 8-K filed on July 6, 2007 and incorporated herein by reference.)

10(c) Credit Agreement between Trunkline LNG Holdings, LLC, as borrower, Panhandle Eastern Pipeline Company, LP and Trunkline LNG Company, LLC, as guarantors, the financial institutions listed therein and Hypo-Und Vereinsbank AG, New York Branch, as administrative agent, dated as of March 15, 2007. (Filed as Exhibit 10.1 to Southern Union's Current Report on Form 8-K filed on March 21, 2007 and incorporated herein by reference.)

10(d) Fourth Amended and Restated Revolving Credit Agreement between Southern Union Company and the Banks named therein dated September 29, 2005. (Filed as Exhibit 10.1 to Southern Union's Current Report on Form 8-K filed on October 5, 2005 and incorporated herein by reference.)

10(e) First Amendment to the Fourth Amended and Restated Revolving Credit Agreement between Southern Union Company and the Banks named therein. (Filed as Exhibit 10.1 to Southern Union's Current Report on Form 8-K filed on March 6, 2006 and incorporated herein by reference.)

10(f) Second Amendment to Fourth Amended and Restated Revolving Credit Agreement dated September 29, 2005, among the Company, as borrower, and the lenders party there. (Filed as Exhibit 10.1 to Southern Union's Current Report on Form 8-K filed on October 23, 2007 and incorporated herein by reference.)

10(g) Form of Indemnification Agreement between Southern Union Company and each of the Directors of Southern Union Company. (Filed as Exhibit 10(i) to Southern Union's Annual Report on Form 10-K for the year ended December 31, 1986 and incorporated herein by reference.)

10(h) Southern Union Company 1992 Long-Term Stock Incentive Plan, As Amended. (Filed as Exhibit 10(l) to Southern Union's Annual Report on Form 10-K for the year ended June 30, 1998 and incorporated herein by reference.)

10(i) Southern Union Company Director's Deferred Compensation Plan. (Filed as Exhibit 10(g) to Southern Union's Annual Report on Form 10-K for the year ended December 31, 1993 and incorporated herein by reference.)

10(j) First Amendment to Southern Union Company Director's Deferred Compensation Plan, effective April 1, 2007. (Filed as Exhibit 10(h) to Southern Union Company's Quarterly Report for the quarter ended September 30, 2007 and incorporated herein by reference.)

10(k) Southern Union Company Amended Supplemental Deferred Compensation Plan with Amendments. (Filed as Exhibit 4 to Southern Union's Form S-8 filed May 27, 1999 and incorporated herein by reference.)

10(l) Separation Agreement and General Release Agreement between Thomas F. Karam and Southern Union Company dated November 8, 2005. (Filed as Exhibit 10.1 to Southern Union's Current Report on Form 8-K filed on November 8, 2005 and incorporated herein by reference.)

10(m) Separation Agreement and General Release Agreement between John E. Brennan and Southern Union Company dated July 1, 2005. (Filed as Exhibit 10.1 to Southern Union's Current Report on Form 8-K filed on July 5, 2005 and incorporated herein by reference.)

10(n) Separation Agreement and General Release Agreement between David J. Kvapil and Southern Union Company dated July 1, 2005. (Filed as Exhibit 10.4 to Southern Union's Current Report on Form 8-K filed on July 5, 2005 and incorporated herein by reference.)

10(o) Second Amended and Restated Southern Union Company 2003 Stock and Incentive Plan. (Filed as Exhibit 4 to Form S-8, SEC File No. 333-138524, filed on November 8, 2006 and incorporated herein by reference.)

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10(p) Southern Union Company Pennsylvania Division Stock Incentive Plan. (Filed as Exhibit 4 to Form S-8, SEC File No. 333-36146, filed on May 3, 2000 and incorporated herein by reference.)

10(q) Southern Union Company Pennsylvania Division 1992 Stock Option Plan. (Filed as Exhibit 4 to Form S-8, SEC File No. 333-36150, filed on May 3, 2000 and incorporated herein by reference.)

10(r) Form of Long Term Incentive Award Agreement, dated December 28, 2006, between Southern Union Company and the undersigned. (Filed as Exhibit 99.1 to Southern Union's Form 8-K dated January 3, 2007) and incorporated herein by reference.)

10(s) Capital Stock Agreement dated June 30, 1986, as amended April 3, 2000 ("Agreement"), among El Paso Energy Corporation (as successor in interest to Sonat, Inc.); CrossCountry Energy, LLC (assignee of Enron Corp., which is the successor in interest to InterNorth, Inc. by virtue of a name change and successor in interest to Houston Natural Gas Corporation by virtue of a merger) and Citrus Corp. (Filed as Exhibit 10(p) to Southern Union's Form 10-K dated March 1, 2007 and incorporated herein by reference.)

10(t) Certificate of Incorporation of Citrus Corp. (Filed as Exhibit 10(q) to Southern Union's Form 10-K dated March 1, 2007 and incorporated herein by reference.)

10(u) By-Laws of Citrus Corp., filed herewith. (Filed as Exhibit 10(r) to Southern Union's Form 10-K dated March 1, 2007 and incorporated herein by reference.)

12 Ratio of earnings to fixed charges.

14 Code of Ethics and Business Conduct. (Filed as Exhibit 14 to Southern Union's Annual Report on Form 10-K filed on March 16, 2006 and incorporated herein by reference.)

21 Subsidiaries of the Registrant.

23.1 Consent of Independent Registered Public Accounting Firm for Southern Union Company.

23.2 Consent of Independent Registered Public Accounting Firm for Citrus Corp.

24 Power of Attorney.

31.1 Certificate by Chief Executive Officer pursuant to Rule 13a-14(a) or Rule 15d-14(a) promulgated under the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.2 Certificate by Chief Financial Officer pursuant to Rule 13a-14(a) or Rule 15d-14(a) promulgated under the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32.1 Certificate by Chief Executive Officer pursuant to Rule 13a-14(b) or Rule 15d-14(b) promulgated under the Securities Exchange Act of 1934 and Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350.

32.2 Certificate by Chief Financial Officer pursuant to Rule 13a-14(b) or Rule 15d-14(b) promulgated under the Securities Exchange Act of 1934 and Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, Southern Union has duly caused this report to be signed by the undersigned, thereunto duly authorized, on February 29, 2008.

SOUTHERN UNION COMPANY

By: /s/ George L. Lindemann
George L. Lindemann
Chairman of the Board, President and
Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of Southern Union and in the capacities indicated as of February 29, 2008.

Signature/Name	Title
/s/ George L. Lindemann* George L. Lindemann	Chairman of the Board, President and Chief Executive Officer (Principal Executive Officer)
/s/ Richard N. Marshall Richard N. Marshall	Senior Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ George E. Aldrich George E. Aldrich	Vice President and Controller (Chief Accounting Officer)
/s/ David Brodsky* David Brodsky	Director
/s/ Frank W. Denius* Frank W. Denius	Director
/s/ Kurt A. Gitter, M.D.* Kurt A. Gitter, M.D	Director
/s/ Herbert H. Jacobi* Herbert H. Jacobi	Director
/s/ Adam M. Lindemann* Adam M. Lindemann	Director
/s/ Thomas N. McCarter, III* Thomas N. McCarter, III	Director
/s/ George Rountree, III* George Rountree, III	Director
/s/ Allan D. Scherer* Allan Scherer	Director

*By: /s/ RICHARD N. MARSHALL
Richard N. Marshall
Senior Vice President and Chief Financial Officer
Attorney-in-fact

*By: /s/ ROBERT M. KERRIGAN, III
Robert M. Kerrigan, III
Vice President, Assistant General Counsel and
Secretary
Attorney-in-fact

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SOUTHERN UNION COMPANY AND SUBSIDIARIES
INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

All schedules are omitted as the required information is not applicable or the information is presented in the consolidated financial statements or related notes.

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SOUTHERN UNION COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF OPERATIONS

	Years Ended December 31, 2007	2006	2005
	(In thousands, except per share amounts)		
Operating revenues (Note 21):			
Gas distribution	$ 732,109	$ 668,721	$ 752,699
Gas transportation and storage	658,446	577,182	505,233
Gas gathering and processing	1,221,747	1,090,216	-
Other	4,363	4,025	8,950
Total operating revenues	2,616,665	2,340,144	1,266,882
Operating expenses:			
Cost of gas and other energy	1,483,715	1,377,147	529,450
Revenue-related taxes	38,584	35,281	40,080
Operating, maintenance and general	444,408	381,844	302,025
Depreciation and amortization	177,999	152,103	92,562
Taxes, other than on income and revenues	44,874	38,684	33,648
Total operating expenses	2,189,580	1,985,059	997,765
Operating income	427,085	355,085	269,117
Other income (expenses):			
Interest expense	(203,146)	(210,043)	(128,470)
Earnings from unconsolidated investments	100,914	141,370	70,742
Other, net (Note 4)	(883)	39,918	(8,241)
Total other expenses, net	(103,115)	(28,755)	(65,969)
Earnings from continuing operations before income taxes	323,970	326,330	203,148
Federal and state income taxes (Note 15)	95,259	109,247	50,052
Earnings from continuing operations	228,711	217,083	153,096
Discontinued operations (Note 19):			
Loss from discontinued operations before income taxes	-	(2,369)	(111,588)
Federal and state income taxes	-	150,583	20,825
Loss from discontinued operations	-	(152,952)	(132,413)
Net earnings	228,711	64,131	20,683
Preferred stock dividends	(17,365)	(17,365)	(17,365)
Net earnings available for common stockholders	$ 211,346	$ 46,766	$ 3,318
Net earnings available for common stockholders from continuing operations per share (Note 5):			
Basic	$ 1.76	$ 1.74	$ 1.24
Diluted	$ 1.75	$ 1.70	$ 1.20
Net earnings available for common stockholders per share (Note 5):			
Basic	$ 1.76	$ 0.41	$ 0.03

Diluted	$ 1.75	$ 0.40	$ 0.03
Cash dividends declared on common stock per share:	$ 0.45	$ 0.40	N/A
Weighted average shares outstanding (Note 5):			
Basic	119,930	114,787	109,395
Diluted	120,674	117,344	112,794

The accompanying notes are an integral part of these consolidated financial statements.

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SOUTHERN UNION COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEET

ASSETS

	Years Ended December 31, 2007	2006
	(In thousands)	
Current assets:		
Cash and cash equivalents	$ 5,690	$ 5,751
Accounts receivable, billed and unbilled, net of allowances of $4,144 and $4,830, respectively	358,521	298,231
Accounts receivable – affiliates	29,943	3,546
Inventories	263,618	241,137
Deferred gas purchase costs	3,496	-
Gas imbalances - receivable	105,371	69,877
Prepayments and other assets	41,685	72,317
Total current assets	808,324	690,859
Property, plant and equipment (Note 6):		
Plant in service	5,509,992	5,025,631
Construction work in progress	377,918	178,935
	5,887,910	5,204,566
Less accumulated depreciation and amortization	(785,623)	(620,139)
Net property, plant and equipment	5,102,287	4,584,427
Deferred charges:		
Regulatory assets (Note 8)	64,193	65,865
Deferred charges	60,468	61,602
Total deferred charges	124,661	127,467
Unconsolidated investments (Note 9)	1,240,420	1,254,749
Goodwill (Note 7)	89,227	89,227
Other	32,994	36,061
Total assets	$ 7,397,913	$ 6,782,790

The accompanying notes are an integral part of these consolidated financial statements.

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SOUTHERN UNION COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEET

STOCKHOLDERS' EQUITY AND LIABILITIES

	Years Ended December 31, 2007	2006
	(In thousands)	
Stockholders' equity (Note 10):		
Common stock, $1 par value; 200,000 shares authorized; 121,102 shares issued at December 31, 2007	$ 121,102	$ 120,718
Preferred stock, no par value; 6,000 shares authorized; 920 shares issued at December 31, 2007 (Note 12)	230,000	230,000
Premium on capital stock	1,784,223	1,775,763
Less treasury stock: 1,063 and 1,059 shares, respectively, at cost	(27,839)	(27,708)
Less common stock held in trust: 783 and 863 shares, respectively	(15,085)	(14,628)
Deferred compensation plans	15,148	14,691
Accumulated other comprehensive loss	(11,594)	(901)
Retained earnings (deficit)	109,851	(47,527)
Total stockholders' equity	2,205,806	2,050,408
Long-term debt obligations (Note 13)	2,960,326	2,689,656
Total capitalization	5,166,132	4,740,064
Current liabilities:		
Long-term debt due within one year (Note 13)	434,680	461,011
Notes payable (Note 13)	123,000	100,000
Accounts payable and accrued liabilities	335,253	316,764
Federal, state and local taxes payable	35,461	30,828
Accrued interest	45,911	46,342
Customer deposits	17,589	14,670
Deferred gas purchases	-	15,551
Gas imbalances - payable	272,850	146,995
Other	58,969	68,663
Total current liabilities	1,323,713	1,200,824
Deferred credits	215,063	224,725
Accumulated deferred income taxes (Note 15)	693,005	617,177
Commitments and contingencies (Note 18)		
Total stockholders' equity and liabilities	$ 7,397,913	$ 6,782,790

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The accompanying notes are an integral part of these consolidated financial statements.

SOUTHERN UNION COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF CASH FLOWS

	Years Ended December 31,		
	2007	2006	2005
		(In thousands)	
Cash flows provided by (used in) operating activities:			
Net earnings	$ 228,711	$ 64,131	$ 20,683
Adjustments to reconcile net earnings to net cash flows provided by (used in) operating activities:			
Depreciation and amortization	177,999	154,601	126,393
Goodwill impairment	-	-	175,000
Amortization of debt expense, net	743	12,130	2,186
Deferred income taxes	71,147	225,843	61,211
Provision for bad debts	11,391	20,151	22,519
Provision for impairment of other assets	7,660	6,500	2,338
(Gain) loss on derivative	9	(55,146)	-
Loss on sale of subsidiaries and other assets	-	56,815	-
Non-cash stock compensation	3,345	6,804	3,848
Earnings from unconsolidated investments, adjusted for cash distributions	2,636	(92,607)	(55,742)
Other	12,999	(5,643)	(1,821)
Changes in operating assets and liabilities, net of acquisitions:			
Accounts receivable, billed and unbilled	(76,778)	147,450	(126,590)
Accounts payable and accrued liabilities	(22,788)	(67,021)	43,681
Customer deposits	2,919	3,542	2,940
Deferred gas purchase costs	(19,047)	(35,906)	59,385
Inventories	41,113	(14,369)	(52,420)
Deferred charges and credits	(3,443)	(37,459)	(26,849)
Prepaids and other assets	47,700	104,889	(41,256)
Taxes and other liabilities	(15,908)	(35,900)	3,131
Net cash flows provided by operating activities	470,408	458,805	218,637
Cash flows (used in) provided by investing activities:			
Additions to property, plant and equipment	(616,883)	(347,896)	(279,721)
Acquisitions of operations, net of cash received	-	(1,537,627)	-
Proceeds (payments) from sale of subsidiaries	(49,304)	1,076,714	-
Other	(417)	2,005	(2,808)
Net cash flows used in investing activities	(666,604)	(806,804)	(282,529)
Cash flows provided by (used in) financing activities:			
Decrease in book overdraft	(7,738)	(4,941)	(17,091)
Issuance of long-term debt	755,000	1,065,000	255,626
Issuance costs of debt and equity	(5,794)	(10,590)	(3,536)
Issuance of common stock and equity units	-	125,000	431,772
Issuance of Bridge Loan	-	1,600,000	-
Repayment of Bridge Loan	-	(1,600,000)	-
Dividends paid on common and preferred stock	(65,295)	(51,695)	(17,365)
Repayment of debt and capital lease obligation	(508,406)	(470,365)	(335,567)
Net (payments) borrowings under revolving credit facilities	23,000	(320,000)	(279,000)
Proceeds from exercise of stock options	3,718	9,216	22,242
Other	1,650	(4,813)	(6,304)
Net cash flows provided by financing activities	196,135	336,812	50,777
Change in cash and cash equivalents	(61)	(11,187)	(13,115)
Cash and cash equivalents at beginning of period	5,751	16,938	30,053
Cash and cash equivalents at end of period	$ 5,690	$ 5,751	$ 16,938

Cash paid for interest, net of amounts capitalized	$ 213,656	$ 204,573	$ 139,770
Cash paid for income taxes, net of refunds	13,979	50,750	(2,007)

The accompanying notes are an integral part of these consolidated financial statements.

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SOUTHERN UNION COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY AND COMPREHENSIVE INCOME

	Common Stock, $1 Par Value	Preferred Stock, No Par Value	Premium on Capital Stock	Treasury Stock, at cost	Common Stock Held In Trust	Deferred Compen-sation Plans	Accumulated Other Comprehensive Income (Loss)	Retained Earnings (Deficit)	To St Ho Eq
					(In thousands)				
Balance December 31, 2004	$ 90,763	$ 230,000	$ 1,204,590	$ (12,870)	$ (17,980)	$ 14,128	$ (59,118)	$ 48,044	$ 1,
Comprehensive income (loss):									
Net earnings	-	-	-	-	-	-	-	20,683	
Unrealized gain on hedging activities, net of tax	-	-	-	-	-	-	1,075	-	
Minimum pension liability adjustment, net of tax	-	-	-	-	-	-	1,771	-	
Comprehensive income									
Preferred stock dividends	-	-	-	-	-	-	-	(17,365)	(
Distibution of common stock held in trust	-	-	3,130	-	4,186	-	-	-	
Issuance of common stock	14,913	-	316,859	-	-	-	-	-	
Issuance cost of equity units	-	-	(2,622)	-	-	-	-	-	
Restricted stock award	-	-	4,998	-	-	(4,998)	-	-	
Restricted stock amortization	-	-	-	-	-	2,198	-	-	
Contract adjustment payment	-	-	(1,759)	-	-	-	-	-	
Purchase of treasury stock	-	-	-	(15,032)	-	-	-	-	(
5% stock dividend	5,294	-	129,121	-	-	-	-	(134,415)	
Stock option award	-	-	3,848	-	-	-	-	-	
Exercise of stock options	1,560	-	20,617	336	(271)	-	-	-	
Payment on note receivable	-	-	2,385	-	-	-	-	-	
Contributions to Trust	-	-	-	-	(1,025)	1,025	-	-	

Disbursements from Trust	-	-	-	-	2,180	(2,180)	-	-	
Balance December 31, 2005	$ 112,530	$ 230,000	$ 1,681,167	$ (27,566)	$ (12,910)	$ 10,173	$ (56,272)	$ (83,053)	$ 1,
Comprehensive income (loss):									
Net earnings	-	-	-	-	-	-	-	64,131	
Unrealized loss on hedging activities, net of tax	-	-	-	-	-	-	918	-	
Change in fair value of hedging derivatives, net of tax	-	-	-	-	-	-	5,276	-	
Reversal of minimum pension liability related to disposition	-	-	-	-	-	-	26,331	-	
Minimum pension liability adjustment, net of tax	-	-	-	-	-	-	6,803	-	
Comprehensive income									
Adjustment to initially apply FASB Statement No. 158	-	-	-	-	-	-	16,043	-	
Preferred stock dividends	-	-	(8,683)	-	-	-	-	(8,682)	(
Cash dividends declared	-	-	(26,366)	-	-	-	-	(19,923)	(
Share-based compensation	-	-	6,804	-	-	-	-	-	
Implementation of FAS 123R	-	-	(2,800)	-	-	2,800	-	-	
Restricted stock awards	146	-	(146)	(142)	-	-	-	-	
Exercise of stock options	629	-	9,544	-	-	-	-	-	
Contributions to Trust	-	-	-	-	(3,079)	3,079	-	-	
Disbursements from Trust	-	-	-	-	1,361	(1,361)	-	-	
Equity Units Conversion	7,413	-	116,243	-	-	-	-	-	
Balance December 31, 2006	$ 120,718	$ 230,000	$ 1,775,763	$ (27,708)	$ (14,628)	$ 14,691	$ (901)	$ (47,527)	$ 2,

The accompanying notes are an integral part of these consolidated financial statements.

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SOUTHERN UNION COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY AND COMPREHENSIVE INCOME

(Continued)

	Common Stock, $1 Par Value	Preferred Stock, No Par Value	Premium on Capital Stock	Treasury Stock, at cost	Common Stock Held In Trust	Deferred Compensation Plans	Accumulated Other Comprehensive Income (Loss)	Retained Earnings (Deficit)	Total Stockholders' Equity
					(In thousands)				
Balance December 31, 2006	$120,718	$ 230,000	$1,775,763	$ (27,708)	$ (14,628)	$ 14,691	$ (901)	$ (47,527)	$2,050,408
Comprehensive income (loss):									
Net earnings	-	-	-	-	-	-	-	228,711	228,711
Reclassification of unrealized gain on hedging activities, net of tax	-	-	-	-	-	-	(4,001)	-	(4,001)
Change in fair value of hedging derivatives, net of tax	-	-	-	-	-	-	(11,320)	-	(11,320)
Realized gain (loss) on interest rate hedges, net of tax	-	-	-	-	-	-	(2,366)		(2,366)
Recognized actuarial gain (loss) and prior service credit (cost), net of tax	-	-	-	-	-	-	6,994	-	6,994
Comprehensive income	-	-	-	-	-	-	-	-	218,018
Preferred stock dividends	-	-	-	-	-	-	-	(17,365)	(17,365)
Cash dividends declared	-	-	-	-	-	-	-	(53,968)	(53,968)
Share-based compensation	-	-	3,345	-	-	-	-	-	3,345
Restricted stock issuances	111	-	(111)	(131)	-	-	-	-	(131)
Exercise of stock options	273	-	5,226	-	-	-	-	-	5,499
Contributions to Trust	-	-	-	-	(769)	769	-	-	-
Disbursements from Trust	-	-	-	-	312	(312)	-	-	-
Balance December 31, 2007	$121,102	$ 230,000	$1,784,223	$ (27,839)	$ (15,085)	$ 15,148	$ (11,594)	$109,851	$2,205,806

The Company's common stock is $1 par value. Therefore, the change in Common Stock, $1 par value, is equivalent to the change in the number of shares of common stock issued.

The accompanying notes are an integral part of these consolidated financial statements.

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SOUTHERN UNION COMPANY AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Corporate Structure

Operations. Southern Union Company (*Southern Union* and, together with its subsidiaries, the *Company*) was incorporated under the laws of the State of Delaware in 1932. The Company owns and operates assets in the regulated and unregulated natural gas industry and is primarily engaged in the gathering, processing, transportation, storage and distribution of natural gas in the United States. Through Southern Union's wholly-owned subsidiary, Panhandle Eastern Pipe Line Company, LP (*PEPL*), and its subsidiaries (collectively, *Panhandle*), the Company owns and operates approximately 10,000 miles of interstate pipelines that transport up to 5.3 billion cubic feet per day (*Bcf/d*) of natural gas from the Gulf of Mexico, South Texas and the Panhandle regions of Texas and Oklahoma to major U.S. markets in the Midwest and Great Lakes regions. Panhandle also owns and operates a liquefied natural gas (*LNG*) import terminal, located on Louisiana's Gulf Coast, which is one of the largest operating LNG facilities in North America. Through its investment in Citrus Corp. (*Citrus*), the Company has an interest in and operates Florida Gas Transmission Company (*Florida Gas*), an interstate pipeline company that transports natural gas from producing areas in South Texas through the Gulf Coast region to Florida. See the related discussion of the change in ownership interests of CCE Holdings, LLC (*CCE Holdings*) on December 1, 2006 applicable to Florida Gas and Transwestern Pipeline Company, LLC (*Transwestern*) in *Note 3 – Acquisitions and Sales – CCE Holdings Transactions*. Through Southern Union's wholly-owned subsidiary, Southern Union Gas Services (*SUGS),* the Company owns approximately 4,800 miles of natural gas and natural gas liquids (*NGLs*) pipelines, four active cryogenic plants with a combined capacity of 410 million cubic feet per day (*MMcf/d*) and five active natural gas treating plants with a combined throughput of 470 MMcf/d. SUGS is primarily engaged in connecting wells of natural gas producers to its gathering system, treating natural gas to remove impurities to meet pipeline quality specifications, processing natural gas for the removal of NGLs, and redelivering natural gas and NGLs to a variety of markets. The operations are located primarily throughout Texas and in the southwestern United States. Through Southern Union's regulated utility operations, Missouri Gas Energy and the Massachusetts operations of New England Gas Company, the Company serves natural gas end-user customers in Missouri and Massachusetts, respectively. The Company's discontinued operations relate to its PG Energy natural gas distribution division in Pennsylvania and the Rhode Island operations of its New England Gas Company natural gas distribution division, which were sold on August 24, 2006.

2. Summary of Significant Accounting Policies

Basis of Presentation. The Company's consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America (*GAAP*).

Principles of Consolidation. The consolidated financial statements include the accounts of Southern Union and its wholly-owned subsidiaries. Investments in which the Company has significant influence over the operations of the investee are accounted for using the equity method. All significant intercompany accounts and transactions are eliminated in consolidation. Certain reclassifications have been made to prior years' financial statements to conform to the current year presentation.

Purchase Accounting. The Company's March 1, 2006 acquisition of Sid Richardson Energy Services, Ltd. and related entities (collectively, *Sid Richardson Energy Services*) was accounted for using the purchase method of accounting in accordance with Financial Accounting Standards Board (*FASB*) Statement No. 141, *Business Combinations*. Under this statement, the purchase price paid by the acquirer, including transaction costs, is allocated to the assets and liabilities acquired as of the acquisition date based on their fair value. Determining the fair value of certain assets and liabilities assumed is judgmental in nature and often involves the use of significant estimates and assumptions. Southern Union generally has used outside appraisers to assist in the initial determination of fair value. The appraisal related to Southern Union's acquisition of Sid Richardson Energy Services was finalized in 2006. See *Note 3 – Acquisitions and Sales – Acquisition of Sid Richardson Energy Services.*

Southern Union effectively acquired an additional 25 percent interest in Citrus on December 1, 2006 as a result of the transactions described in *Note 3 – Acquisitions and Sales – CCE Holdings Transactions*. The allocation of fair value associated with this incremental equity investment in Citrus is accounted for under Accounting

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SOUTHERN UNION COMPANY AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Principles Board Opinion 18, *The Equity Method of Accounting for Investments in Common Stock* (*APB 18*). For additional information, see *Note 9 – Unconsolidated Investments – CCE Holdings Goodwill Evaluation*.

Property, Plant and Equipment. Ongoing additions of property, plant and equipment (*PP&E*) are stated at cost. The Company capitalizes all construction-related direct labor and material costs, as well as indirect construction costs. The cost of renewals and betterments that extend the useful life of PP&E is also capitalized. The cost of repairs and replacements of minor PP&E items is charged to expense as incurred.

When PP&E is retired, the original cost less salvage value is charged to accumulated depreciation and amortization. When entire regulated operating units of PP&E are retired or sold or non-regulated properties are retired or sold, the property and related accumulated depreciation and amortization accounts are reduced, and any gain or loss is recorded in earnings.

The Company computes depreciation expense using the straight-line method. Depreciation rates for the utility plants are approved by the applicable regulatory commissions.

Computer software, which is a component of PP&E, is stated at cost and is generally amortized on a straight-line basis over its useful life on a product-by-product basis.

For additional information, see *Note 6 – Property, Plant and Equipment*.

Use of Estimates. The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Cash and Cash Equivalents. The Company considers all highly liquid investments with an original maturity of three months or less to be cash equivalents. Short-term investments are highly liquid investments with maturities of more than three months when purchased, and are carried at cost, which approximates market. The Company places its temporary cash investments with a high credit quality financial institution that, in turn, invests the temporary funds in a variety of high-quality short-term financial securities.

Under the Company's cash management system, checks issued but not presented to banks frequently result in book overdraft balances for accounting purposes and are classified in accounts payable in the Consolidated Balance Sheet. At December 31, 2007 and December 31, 2006, such book overdraft balances classified in accounts payable were approximately $37.5 million and $45.3 million, respectively.

Segment Reporting. FASB Statement No. 131, *Disclosures about Segments of an Enterprise and Related Information*, requires disclosure of segment data based on how management makes decisions about allocating resources to segments and measuring performance. The Company is principally engaged in the transportation and storage, gathering and processing and distribution of natural gas in the United States, and reports these operations under three reportable segments: the Transportation and Storage segment, the Gathering and Processing segment and the Distribution segment. See *Note 21 – Reportable Segments*.

Transportation and Storage Revenues. In the Transportation and Storage segment, revenues from transportation and storage of natural gas and LNG terminalling are based on capacity reservation charges and commodity usage charges. Reservation revenues are based on contracted rates and capacity reserved by customers and are recognized monthly. Revenues from commodity usage charges are also recognized monthly, based on the volumes received from or delivered to customers, depending on the tariff of that particular entity, with any differences in received and delivered volumes resulting in an imbalance. Volume imbalances generally are settled in-kind with no impact on revenues, with the exception of PEPL's subsidiary, Trunkline Gas Company, LLC (*Trunkline*), which settles imbalances in cash pursuant to its tariff, and records gains and losses on such cashout sales as a component of revenue, to the extent not owed back to customers.

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SOUTHERN UNION COMPANY AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Gathering and Processing Revenues and Cost of Sales Recognition. Revenue and the related cost of sales for natural gas and NGLs are recognized in the period when the physical product is delivered to the customer at the contractually agreed-upon price and title is transferred. Cost of sales primarily includes the cost of purchased natural gas and NGLs.

SUGS accounts for sale and purchase arrangements on a gross basis in the Consolidated Statement of Operations as *Operating revenues* and *Cost of gas and other energy*, respectively. Contractual arrangements establish the purchase of natural gas and NGLs at specified locations and the sale at different locations on the same or other specified dates. Both purchase and sale transactions require physical delivery of the natural gas and NGLs. The transfer of ownership is evidenced by the purchaser's assumption of title, price risk, credit risk, counterparty nonperformance risk, environmental risk, and transportation scheduling.

Gas Distribution Revenues and Gas Purchase Costs. In the Distribution segment, gas utility customers are billed on a monthly-cycle basis. The related cost of gas and revenue taxes are matched with cycle-billed revenues through utilization of purchased gas adjustment provisions in tariffs approved by the regulatory agencies having jurisdiction. Revenues from gas delivered but not yet billed are accrued, along with the related gas purchase costs and revenue-related taxes. Unbilled receivables related to the Distribution segment recorded in *Accounts receivable* in the Consolidated Balance Sheet at December 31, 2007 and 2006 were $56.8 million and $47.3 million, respectively.

Accounts Receivable and Allowance for Doubtful Accounts. The Company manages trade credit risks to minimize exposure to uncollectible trade receivables. In the Transportation and Storage and Gathering and Processing segments, prospective and existing customers are reviewed for creditworthiness based upon pre-established standards. Customers that do not meet minimum standards are required to provide additional credit support. In the Distribution segment, concentrations of credit risk in trade receivables are limited due to the large customer base with relatively small individual account balances. Additionally, the Company requires a deposit from customers in the Distribution segment who lack a credit history or whose credit rating is substandard. The Company utilizes the allowance method for recording its allowance for uncollectible accounts, which is primarily based on the application of historical bad debt percentages applied against its aged accounts receivable. Increases in the allowance are recorded as a component of operating expenses. Reductions in the allowance are recorded when receivables are written off or subsequently collected.

The following table presents the balance in the allowance for doubtful accounts and activity for the years ended December 31, 2007, 2006 and 2005:

	Years Ended December 31, 2007	2006	2005
		(In thousands)	
Beginning balance	$ 4,830	$ 15,893	$ 15,424
Additions: charged to cost and expenses (1)	11,391	9,646	22,519
Deductions: write-off of uncollectible accounts	(12,657)	(9,756)	(22,751)
Balance related to discontinued operations (2)	-	(10,968)	-
Other	580	15	701
Ending balance	$ 4,144	$ 4,830	$ 15,893

(1) Additions charged to cost and expenses applicable to continuing operations for the years ended December 31, 2007, 2006 and 2005 were $11.4 million, $9.6 million and $8.5 million, respectively.
(2) Represents elimination of the allowance for doubtful accounts balance resulting from the Company's August 24, 2006 sale of the assets of the PG Energy natural gas distribution division and the Rhode Island operations of its New England Gas Company natural gas distribution division.

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SOUTHERN UNION COMPANY AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Earnings Per Share. The Company's earnings per share (*EPS*) presentation conforms to FASB Statement No. 128, *Earnings per Share*. All share and per share data have been appropriately restated for all stock dividends, unless otherwise stated. See *Note 10 – Stockholders' Equity – Dividends*.

Stock-Based Compensation. The Company follows FASB Statement No. 123(R), *Accounting for Stock-Based Compensation* (*Statement No. 123R*), to account for stock-based employee compensation. The Company adopted Statement No. 123R effective January 1, 2006, using the modified prospective method. The statement requires the Company to measure all employee stock-based compensation using a fair value method and record such expense in its Consolidated Statement of Operations. Prior to adoption of Statement No. 123R, the Company used the intrinsic value method of accounting for stock-based compensation awards in accordance with APB Opinion No. 25, *Accounting for Stock Issued to Employees*, which generally resulted in no compensation expense for employee stock options with an exercise price not less than fair value on the date of grant. For more information, see *Note 24 – Stock-Based Compensation.*

Pursuant to the modified prospective application method of transition, the Company has not adjusted results of operations for prior periods. The following table reflects pro forma net earnings and net EPS adjusted for subsequent stock dividends that the Company would have reported if it had elected to adopt the fair value approach of Statement No. 123 prior to January 1, 2006:

	Year Ended December 31, 2005	
	(In thousands, except per share amounts)	
Net earnings, as reported	$	20,683
Add stock-based compensation expense included in reported net earnings, net of related taxes		3,767
Deduct total stock-based employee compensation expense determined under fair value based method for all awards, net of related taxes		4,355
Pro forma net earnings	$	20,095
Net earnings available for common stockholders per share:		
Basic- as reported	$	0.03
Basic- pro forma	$	0.02
Diluted- as reported	$	0.03
Diluted- pro forma	$	0.02

Accumulated Other Comprehensive Loss. The Company reports comprehensive income and its components in accordance with FASB Statement No. 130, *Reporting Comprehensive Income*. The main components of comprehensive income that relate to the Company are net earnings, unrealized gain (loss) on hedging activities and unrealized actuarial gain (loss) and prior service credits (cost) on pension and other postretirement plans, all of which are presented in the Consolidated Statement of Stockholders' Equity and Comprehensive Income. For more information, see *Note 22 – Accumulated Other Comprehensive Loss.*

Inventories. In the Transportation and Storage segment, inventories consist of gas held for operations and materials and supplies, both of which are carried at the lower of weighted average cost or market, while gas received from or owed back to customers is valued at market. The gas held for operations that the Company

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does not expect to consume in its operations in the next 12 months is reflected in non-current assets. Gas held for operations at December 31, 2007 was $187 million, or 26,001,000 million British thermal units (*MMBtu*), of which $19 million was classified as non-current. Gas held for operations at December 31, 2006 was $129 million, or 20,965,000 MMBtu, of which $14.9 million was classified as non-current. Materials and supplies include spare parts which are critical to the pipeline system operations and are valued at the lower of cost or market. Materials and supplies inventory in the Transportation and Storage segment were $12.8 million and $13.2 million at December 31, 2007 and 2006, respectively.

In the Gathering and Processing segment, inventories consist of materials and supplies and are stated at the lower of weighted average cost or market. Materials and supplies in the Gathering and Processing segment, primarily comprised of compressor components and parts, were $6.2 million and $6.9 million at December 31, 2007 and 2006, respectively.

In the Distribution segment, inventories consist of natural gas in underground storage and materials and supplies, both of which are carried at weighted average cost. Natural gas in underground storage at December 31, 2007 and 2006 was $72.8 million and $103.5 million, respectively, and consisted of 11,823,474 and 14,702,000 MMBtu, respectively. Materials and supplies inventories in the Distribution segment were $3.8 million and $3.7 million at December 31, 2007 and 2006, respectively.

Unconsolidated Investments. Investments in affiliates over which the Company may exercise significant influence, generally 20 percent to 50 percent ownership interests, are accounted for using the equity method. Any excess of the Company's investment in affiliates, as compared to its share of the underlying equity, that is not recognized as goodwill is amortized over the estimated economic service lives of the underlying assets. Other investments over which the Company may not exercise significant influence are accounted for under the cost method. The Company reviews its portfolio of unconsolidated investment securities on a quarterly basis to determine whether a decline in value is other-than-temporary. Factors that are considered in assessing whether a decline in value is other-than-temporary include, but are not limited to, the following: earnings trends and asset quality; near term prospects and financial condition of the issuer, including the availability and terms of any additional financing requirements; financial condition and prospects of the issuer's region and industry, customers and markets; and the Company's intent and ability to retain the investment. If the Company determines that a decline in value of an investment security is other-than-temporary, the Company will record a charge in its Consolidated Statement of Operations to reduce the carrying value of the security to its estimated fair value. Write-downs associated with equity-method investments are recognized in *Earnings from unconsolidated investments* in the Consolidated Statement of Operations, and write-downs associated with cost-method investments are recognized in *Other income (expenses), net*, in the Consolidated Statement of Operations. See *Note 9 – Unconsolidated Investments*.

Regulatory Assets and Liabilities. The Company is subject to regulation by certain state and federal authorities. In its Distribution segment and for certain of its operations reported as discontinued operations, the Company has accounting policies that conform to FASB Statement No. 71, *Accounting for the Effects of Certain Types of Regulation* (*Statement No. 71*), and are in accordance with the accounting requirements and ratemaking practices of the regulatory authorities. The application of these accounting policies allows the Company to defer expenses and revenues on the balance sheet as regulatory assets and liabilities when it is probable that those expenses and revenues will be allowed in the ratemaking process in a period different from the period in which they would have been reflected in the Consolidated Statement of Operations by an unregulated company. These deferred assets and liabilities then flow through the results of operations in the period in which the same amounts are included in rates and recovered from or refunded to customers. Management's assessment of the probability of recovery or pass through of regulatory assets and liabilities requires judgment and interpretation of laws and regulatory commission orders. If, for any reason, the Company ceases to meet the criteria for application of regulatory accounting treatment for all or part of its operations, the regulatory assets and liabilities related to those portions ceasing to meet such criteria would be eliminated from the Consolidated Balance Sheet and included in the Consolidated Statement of Operations for the period in which the discontinuance of regulatory accounting treatment occurs. See *Note 8 – Regulatory Assets.*

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Goodwill. The Company accounts for its goodwill and other intangible assets in accordance with FASB Statement No. 142, *Accounting for Goodwill and Other Intangible Assets*. Goodwill acquired in a purchase business combination and determined to have an indefinite useful life is not amortized, but instead is tested for impairment at a reporting unit level at least annually by applying a fair-value based test. The Company's goodwill is related to its Distribution segment. See *Note 7 – Goodwill*.

Fair Value of Financial Instruments. The carrying amounts reported in the Consolidated Balance Sheet for cash and cash equivalents, accounts receivable, accounts payable, derivative instruments and notes payable approximate their fair value. The fair value of the Company's long-term debt is estimated using current market quotes and other estimation techniques. See *Note 13 – Debt Obligations*.

Gas Imbalances. In the Transportation and Storage and Gathering and Processing segments, gas imbalances occur as a result of differences in volumes of gas received and delivered. In the Transportation and Storage segment, the Company records gas imbalance in-kind receivables and payables at cost or market, based on whether net imbalances have reduced or increased system gas balances, respectively. Net imbalances that have reduced system gas are valued at the cost basis of the system gas, while net imbalances that have increased system gas and are owed back to customers are priced, along with the corresponding system gas, at market.

In the Gathering and Processing segment, the Company records gas imbalances at the lower of cost or market. Imbalances due to a pipeline are recorded at market and imbalances due from a pipeline are recorded at the lower of cost or market. Market prices are based upon gas daily indexes.

Fuel Tracker. Liability accounts are maintained in the Transportation and Storage segment for net volumes of fuel gas owed to customers collectively. Whenever fuel is due from customers from prior under-recovery based on contractual and specific tariff provisions, Trunkline and Trunkline LNG Company, LLC (*Trunkline LNG*) record an asset. Panhandle's other companies that are subject to fuel tracker provisions record an expense when fuel is under-recovered. The pipelines' fuel reimbursement is in-kind and non-discountable.

Interest Cost Capitalized. The Company capitalizes interest on certain qualifying assets that are undergoing activities to prepare them for their intended use in accordance with FASB Statement No. 34, *Capitalization of Interest Cost*. Interest costs incurred during the construction period are capitalized and amortized over the life of the assets. Capitalized interest for the years ended December 31, 2007, 2006 and 2005 was $14.7 million, $5.4 million and $9 million, respectively.

Derivative Instruments and Hedging Activities. The Company follows FASB Statement No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended (*Statement No. 133*), to account for derivative and hedging activities. In accordance with this statement, all derivatives are recognized on the Consolidated Balance Sheet at their fair value. On the date the derivative contract is entered into, the Company designates the derivative as (i) a hedge of the fair value of a recognized asset or liability or of an unrecognized firm commitment (*a fair value hedge*); (ii) a hedge of a forecasted transaction or the variability of cash flows to be received or paid in conjunction with a recognized asset or liability (*a cash flow hedge*); or (iii) an instrument that is held for trading or non-hedging purposes (*a trading or economic hedging instrument*). For derivatives treated as a fair value hedge, the effective portion of changes in fair value are recorded as an adjustment to the hedged item. The ineffective portion of a fair value hedge is recognized in earnings if the short cut method of assessing effectiveness is not used. Upon termination of a fair value hedge of a debt instrument, the resulting gain or loss is amortized to earnings through the maturity date of the debt instrument. For derivatives treated as a cash flow hedge, the effective portion of changes in fair value is recorded in *Accumulated other comprehensive loss* until the related hedged items impact earnings. Any ineffective portion of a cash flow hedge is reported in current-period earnings. For derivatives treated as trading or economic hedging instruments, changes in fair value are reported in current-period earnings. Fair value is determined based upon quoted market prices and mathematical models using current and historical data. See *Note 11 – Derivative Instruments and Hedging Activities*.

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Asset Retirement Obligations. The Company accounts for its asset retirement obligations in accordance with FASB Statement No. 143, *Accounting for Asset Retirement Obligations (ARO) (Statement No. 143*) and FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations (FIN No. 47*). These accounting principles require legal obligations associated with the retirement of long-lived assets to be recognized at their fair value at the time the obligations are incurred. Upon initial recognition of a liability, costs are capitalized as part of the related long-lived asset and allocated to expense over the useful life of the asset. The liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related long-lived asset. In certain rate jurisdictions, the Company is permitted to include annual charges for cost of removal in its regulated cost of service rates charged to customers.

For more information, see *Note 20 – Asset Retirement Obligations*.

Income Taxes. Income taxes are accounted for under the asset and liability method in accordance with the provisions of FASB Statement No. 109, *Accounting for Income Taxes*. Under this method, deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis. Deferred tax assets and liabilities are measured using enacted tax rates in effect for the year in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rate is recognized in earnings in the period that includes the enactment date. Valuation allowances are established when necessary to reduce deferred tax assets to the amounts more likely than not to be realized

The determination of the Company's provision for income taxes requires significant judgment, use of estimates, and the interpretation and application of complex tax laws. Significant judgment is required in assessing the timing and amounts of deductible and taxable items. Reserves are established when, despite management's belief that the Company's tax return positions are fully supportable, management believes that certain positions may be successfully challenged. When facts and circumstances change, these reserves are adjusted through the provision for income taxes. Effective January 1, 2007, with the adoption of FIN 48, *Accounting for Uncertainty in Income Tax*es (*FIN 48*), the Company began evaluating its tax reserves under the recognition, measurement and derecognition thresholds as prescribed by FIN 48.

Pensions and Other Postretirement Benefit Plans. Effective December 31, 2006, the Company adopted the recognition and disclosure provisions of Statement No. 158. Statement No. 158 does not amend the expense recognition provisions of Statements No. 87, 88 and 106, but requires employers to recognize in their balance sheets the overfunded or underfunded status of defined benefit postretirement plans, measured as the difference between the fair value of the plan assets and the benefit obligation (the projected benefit obligation for pension plans and the accumulated postretirement benefit obligation for other postretirement plans). Each overfunded plan is recognized as an asset and each underfunded plan is recognized as a liability. Employers must recognize the change in the funded status of the plan in the year in which the change occurs through *Accumulated other comprehensive loss* in stockholders' equity. Effective for years ending after December 15, 2008 (with early adoption permitted), Statement No. 158 also requires plan assets and benefit obligations to be measured as of the employers' balance sheet date. The Company has not yet adopted the measurement date provisions of Statement No. 158.

The Company accounted for the measurement of its defined benefit postretirement plans under Statement No. 87 and Statement No. 106. Prior to the adoption of the recognition and disclosure provisions of Statement No. 158, Statement No. 87 required that a liability (minimum pension liability) be recorded when the accumulated benefit obligation liability exceeded the fair value of plan assets. Any adjustment was recorded as a non-cash charge to *Accumulated other comprehensive loss*. Statement No. 106 had no minimum liability provisions. Under both Statements No. 87 and 106, changes in the funded status were not immediately recognized, rather they were deferred and recognized ratably over future periods. Upon adoption of the recognition provisions of Statement No. 158, the Company recognized the amounts of these prior changes in the funded status of its defined benefit postretirement plans through *Accumulated other comprehensive loss*.

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Commitments and Contingencies. The Company is subject to proceedings, lawsuits and other claims related to environmental and other matters. Accounting for contingencies requires significant judgments by management regarding the estimated probabilities and ranges of exposure to potential liability. For further discussion of the Company's commitments and contingencies, see *Note 18 – Commitments and Contingencies.*

New Accounting Principles

Accounting Principles Recently Adopted.

FIN 48, "Accounting for Uncertainty in Income Taxes - an Interpretation of FASB Statement 109": Issued by the FASB in June 2006, FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with FASB Statement No. 109, *Accounting for Income Taxes*. FIN 48 prescribes a recognition and measurement threshold attributable for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosures and transition. FIN 48 became effective for fiscal years beginning after December 15, 2006. The Company's consolidated financial statements have not been materially impacted by the adoption of FIN 48 as of January 1, 2007. See *Note 15 - Taxes on Income*.

FSP No. FIN 48-1, "Definition of 'Settlement' in FASB Interpretation No. 48" (FIN 48-1): Issued by the FASB in May 2007, FIN 48-1 provides guidance on how an enterprise should determine whether a tax position is effectively settled for the purpose of recognizing previously unrecognized tax benefits. The Company's adoption of FIN 48, effective January 1, 2007, was consistent with FIN 48-1.

Accounting Principles Not Yet Adopted.

FASB Statement No. 157, "Fair Value Measurements": Issued by the FASB in September 2006, this Statement defines fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements. Where applicable, this Statement simplifies and codifies related guidance within GAAP. Except for certain non financial assets and liabilities more fully discussed in FSP No. FAS 157-2, "*Effective Date of FASB Statement No. 157*" (*FSP No. FAS 157*-2) which was issued by the FASB in February 2008, this Statement is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. For those non financial assets and liabilities deferred pursuant to FSP No. FAS 157-2, this Statement is effective for financial statements for fiscal years beginning after November 15, 2008. The Company is currently evaluating the impact of this Statement on its consolidated financial statements.

FASB Statement No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities – Including an Amendment of FASB Statement No. 115": Issued by the FASB in February 2007, this Statement permits entities to choose to measure many financial instruments and certain other items at fair value that are not currently required to be measured at fair value. Unrealized gains and losses on items for which the fair value option has been elected are reported in earnings. The Statement does not affect any existing accounting literature that requires certain assets and liabilities to be carried at fair value. The Statement is effective for fiscal years beginning after November 15, 2007. At January 1, 2008, the Company did not elect the fair value option under the Statement and, therefore, there was no impact to the Company's consolidated financials statements.

FSP No. FIN 39-1, "Amendment of FASB Interpretation No. 39" (FIN 39-1): Issued by the FASB in April 2007, FIN 39-1 impacts entities that enter into master netting arrangements as part of their derivative transactions by allowing net derivative positions to be offset in the financial statements against the fair value of amounts (or amounts that approximate fair value) recognized for the right to reclaim cash collateral or the obligation to return cash collateral under those arrangements. FIN 39-1 is effective for fiscal years beginning after November 15, 2007. The Company has determined the impact of FIN 39-1 will not have a material impact on its consolidated financial statements.

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FASB Statement No. 141 (revised), "Business Combinations". Issued by the FASB in December 2007, this Statement changes the accounting for business combinations including the measurement of acquirer shares issued in consideration for a business combination, the recognition of contingent consideration, the accounting for preacquisition gain and loss contingencies, the recognition of capitalized in-process research and development costs, the accounting for acquisition-related restructuring cost accruals, the treatment of acquisition related transaction costs and the recognition of changes in the acquirer's income tax valuation allowance. The Statement is effective for fiscal years beginning after December 15, 2008, with early adoption prohibited.

FASB Statement No. 160, "Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51". Issued by the FASB in December 2007, this Statement changes the accounting for noncontrolling (minority) interests in consolidated financial statements, including the requirements to classify noncontrolling interests as a component of consolidated stockholders' equity, and the elimination of minority interest accounting in results of operations with earnings attributable to noncontrolling interests reported as part of consolidated earnings. Additionally, the Statement revises the accounting for both increases and decreases in a parent's controlling ownership interest. The Statement is effective for fiscal years beginning after December 15, 2008, with early adoption prohibited. The Company is currently evaluating the impact of this statement on its consolidated financial statements.

Staff Accounting Bulletin No. 110 (SAB 110): Issued by the Securities and Exchange Commission (*SEC*) in December 2007, SAB 110 expresses the views of the SEC staff regarding the use of a "simplified" method, as discussed in SAB No. 107, in developing an estimate of expected term of "plain vanilla" share options in accordance with FAS 123R. The SEC staff indicated in SAB No. 107 that it would accept a company's election to use the simplified method, regardless of whether the company has sufficient information to make more refined estimates of expected term, for options granted prior to December 31, 2007. In SAB 110, the SEC staff states that it will continue to accept, under certain circumstances, the use of the simplified method beyond December 31, 2007. The Company is currently evaluating the impact of SAB 110 on its consolidated financial statements.

3. Acquisitions and Sales

Acquisition of Sid Richardson Energy Services. On March 1, 2006, Southern Union acquired 100 percent of the partnership interests in Sid Richardson Energy Services for approximately $1.6 billion in cash. The acquisition was undertaken by the Company to increase its investment in higher growth businesses. The acquisition was funded under a short-term bridge loan facility in the amount of $1.6 billion (*Sid Richardson Bridge Loan*). See *Note 13 – Debt Obligations – Short-Term Debt Obligations, Excluding Current Portion of Long-Term Debt* for additional information related to the bridge loan facility.

The principal assets of the acquired Sid Richardson Energy Services business, now known as SUGS, are located in the Permian Basin of Texas and New Mexico and include approximately 4,800 miles of natural gas and NGLs pipelines, four active cryogenic plants and five active natural gas treating plants. SUGS' operations are located primarily throughout Texas and in the southwestern United States. SUGS is primarily engaged in connecting wells of natural gas producers to its gathering system, treating natural gas to remove impurities to meet pipeline quality specifications, processing natural gas for the removal of NGLs, and redelivering natural gas and NGLs to a variety of markets. SUGS' primary sales customers include producers, power generating companies, utilities, energy marketers, and industrial users located primarily in the southwestern United States. SUGS receives hydrocarbons for purchase or transportation to market from over 240 producers and suppliers. SUGS' major natural gas pipeline interconnects are with ATMOS Pipeline, El Paso Natural Gas Company, Energy Transfer Fuel, LP, DCP Guadalupe Pipeline, LP, Enterprise Texas Pipeline, Northern Natural Gas Company, Oasis Pipeline, LP, ONEOK Wes Tex Transmission, LP, Public Service Company of New Mexico and Transwestern, a former affiliate of the Company (see *Note 9 – Unconsolidated Investments*). Its major NGLs pipeline interconnects are with Chapparal, Louis Dreyfus and Chevron.

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The acquisition was accounted for using the purchase method of accounting, with the purchase price paid by the Company allocated to SUGS' net assets as of the acquisition date based on their fair values. SUGS' assets acquired and liabilities assumed have been recorded in the Consolidated Balance Sheet beginning March 1, 2006 at their estimated fair values and have been adjusted to reflect the results of a third-party appraisal and final working capital adjustments. SUGS' results of operations have been included in the Consolidated Statement of Operations since March 1, 2006. Thus, the Consolidated Statement of Operations for the periods subsequent to the acquisition are not comparable to the same periods in prior years.

The following table summarizes the estimated fair values of SUGS' assets acquired and liabilities assumed at the date of acquisition.

	At March 1, 2006 (In thousands)
Property, plant and equipment (1)	$ 1,562,835
Current assets (2)	162,793
Unconsolidated investment (3)	5,767
Other non-current assets (4)	2,618
Total assets acquired	1,734,013
Current liabilities	141,244
Deferred taxes	8,427
Other non-current liabilities	634
Total liabilities assumed	150,305
Net assets acquired	$ 1,583,708

(1) Includes an allocation of $13.5 million to other intangibles for leases and software with weighted average lives of 4 years and 1 year respectively.
(2) Includes cash and cash equivalents of approximately $53.7 million.
(3) Represents a 50 percent ownership interest in Grey Ranch Plant LP (*Grey Ranch*).
(4) Except for $33,000 of other non-current assets, balance is comprised of intangibles for customer relationships with a weighted-average life of 3 years.

The following unaudited pro forma financial information for the periods presented is reported as though the acquisition of Sid Richardson Energy Services and the related permanent financing, including utilization of the proceeds from the sales of the Company's Pennsylvania and Rhode Island natural gas distribution divisions,
occurred at January 1, 2005. The pro forma financial information is not necessarily indicative of the results that would have been obtained if the acquisition of Sid Richardson Energy Services and the related financing had been completed as of the assumed date for the period presented or of the results that may be obtained in the future.

	Year Ended December 31, 2006	2005
	(In thousands, except per share amounts)	
Operating revenue	$ 2,570,693	$ 2,636,056
Net earnings available for common shareholders from continuing operations	209,807	163,471
Net earnings available for common shareholders from continuing operations per share:		
Basic	$ 1.83	$ 1.49
Diluted	$ 1.79	$ 1.45

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Sale of PG Energy. On August 24, 2006, the Company completed the sale of the assets of its PG Energy natural gas distribution division to UGI Corporation for approximately $580 million in cash, excluding certain working capital adjustment reductions of approximately $24.4 million, which were paid in the first quarter of 2007. Proceeds from the sale were used to retire a portion of the acquisition debt incurred in connection with Southern Union's $1.6 billion purchase of Sid Richardson Energy Services.

Sale of the Rhode Island Operations of New England Gas Company. On August 24, 2006, the Company completed the sale of the Rhode Island operations of its New England Gas Company natural gas distribution division to National Grid USA for $575 million in cash, less the assumption of approximately $77 million of debt and excluding certain working capital adjustment reductions of approximately $24.9 million, which were paid in the first quarter of 2007. Proceeds from the sale were used to retire a portion of the acquisition debt incurred in connection with Southern Union's $1.6 billion purchase of Sid Richardson Energy Services.

See *Note 7 – Goodwill* and *Note 19 – Discontinued Operations* for additional information, including loss on sales amounts, related to the sales of the assets of the PG Energy natural gas distribution division and the Rhode Island operations of the New England Gas Company natural gas distribution division.

CCE Holdings Transactions.

On December 1, 2006, the Company completed a series of transactions that resulted in it increasing its effective ownership interest in Citrus from 25 percent to 50 percent and eliminating its effective 50 percent ownership interest in Transwestern. On September 14, 2006, Energy Transfer Partners, L.P. (*Energy Transfer*) entered into a definitive purchase agreement to acquire the 50 percent interest in CCE Holdings held by GE Financial Services and other investors. At the same time, Energy Transfer and CCE Holdings entered into a definitive redemption agreement, pursuant to which Energy Transfer's 50 percent ownership interest in CCE Holdings would be redeemed in exchange for 100 percent of the equity interests in Transwestern (*Redemption Agreement*). Upon the closing of the transactions under the Redemption Agreement on December 1, 2006, the Company became the sole owner of 100 percent of CCE Holdings, whose principal remaining asset was its 50 percent interest in Citrus which, in turn, owns 100 percent of Florida Gas. This resulted in the elimination of the Company's prior equity investment in CCE Holdings of $680.9 million from its Consolidated Balance Sheet as of December 1, 2006, and the separate inclusion of Citrus as an equity investment with a balance of $1.23 billion in the Company's Consolidated Balance Sheet. Prior to December 1, 2006, Citrus was a 50 percent equity investment of CCE Holdings and was included within the Company's 50 percent equity interest in CCE Holdings. The resulting increase in the Company's equity investment from CCE Holdings to Citrus is primarily attributable to the Company becoming obligated to retire $455 million of debt held by CCE Holdings and recognition of a pre-tax $74.8 million gain associated with the transaction. The debt was simultaneously paid off using the proceeds of the $465 million LNG Holdings 2006 Term Loan more fully described in *Note 13 – Debt Obligations*.

Florida Gas is an open-access interstate pipeline system extending approximately 5,000 miles with a capacity of 2.1 Bcf/d from south Texas through the Gulf Coast region of the United States to south Florida. Florida Gas' pipeline system primarily receives natural gas from natural gas producing basins along the Louisiana and Texas Gulf Coast, Mobile Bay and offshore Gulf of Mexico. Florida Gas is the principal transporter of natural gas to the Florida energy market, delivering over 70 percent of the natural gas consumed in the state. In addition, Florida Gas' pipeline system operates and maintains 60 interconnects with major interstate and intrastate natural gas pipelines, which provide Florida Gas' customers access to diverse natural gas producing regions.

At December 1, 2006, Transwestern was an open-access natural gas interstate pipeline extending approximately 2,500 miles with a capacity of 2.1 Bcf/d from the gas producing regions of west Texas, Oklahoma, eastern and northwest New Mexico and southern Colorado primarily to pipeline interconnects off the east end of its system and to the California market. Transwestern has access to three significant gas basins: the Permian Basin in west Texas and eastern New Mexico; the San Juan Basin in northwest New Mexico and southern Colorado; and the Anadarko Basin in the Texas and Oklahoma panhandle.

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4. Other Income and Expense Items

Operating, maintenance and general expense for the year ended December 31, 2007 includes a $6.9 million impairment of the Company's former corporate office building due to a change in the Company's expected proceeds from the sale of the building.

Other, net income of $39.9 million for the year ended December 31, 2006 primarily includes $37.2 million of pre-acquisition mark-to-market gains on put options associated with the acquisition of Sid Richardson Energy Services and $3.2 million in gains on sales of certain assets. See *Note 11 – Derivative Instruments and Hedging Activities – Gathering and Processing Segment*, for more information related to the gain on put options mentioned above.

Other, net expense for the year ended December 31, 2005 of $8.2 million primarily includes charges of $6.3 million to reserve for the other-than-temporary impairment of the Company's investment in separate technology companies and to record a liability for a related loan guaranty (see *Note 9 – Unconsolidated Investments*), partially offset by a $1.8 million gain related to the mark-to-market accounting of put options purchased in connection with the agreement to acquire Sid Richardson Energy Services. See *Note 11 – Derivative Instruments and Hedging Activities – Gathering and Processing Segment* for additional information related to the put options.

5. Earnings Per Share

The following table summarizes the Company's basic and diluted earnings EPS calculations for the years ended December 31, 2007, 2006 and 2005:

	Years Ended December 31,		
	2007	2006	2005
	(In thousands, except per share amounts)		
Net earnings from continuing operations	$ 228,711	$ 217,083	$ 153,096
Loss from discontinued operations	-	(152,952)	(132,413)
Preferred stock dividends	(17,365)	(17,365)	(17,365)
Net earnings available for common stockholders	$ 211,346	$ 46,766	$ 3,318
Weighted average shares outstanding - Basic	119,930	114,787	109,395
Weighted average shares outstanding - Diluted	120,674	117,344	112,794
Basic earnings per share:			
Net earnings available for common stockholders from continuing operations	$ 1.76	$ 1.74	$ 1.24
Loss from discontinued operations	-	(1.33)	(1.21)
Net earnings available for common stockholders	$ 1.76	$ 0.41	$ 0.03
Diluted earnings per share:			
Net earnings available for common stockholders from continuing operations	$ 1.75	$ 1.70	$ 1.20
Loss from discontinued operations	-	(1.30)	(1.17)
Net earnings available for common stockholders	$ 1.75	$ 0.40	$ 0.03

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Basic EPS is computed based on the weighted-average number of common shares outstanding during each period. Diluted EPS is computed based on the weighted-average number of common shares outstanding during each period, increased by common stock equivalents from stock options, stock appreciation rights (*SARs*), warrants, restricted stock and convertible equity units. A reconciliation of the shares used in the basic and diluted EPS calculations is shown in the following table.

	Years Ended December 31,		
	2007	**2006**	**2005**
		(In thousands)	
Weighted average shares outstanding - Basic	119,930	114,787	109,395
Add assumed vesting of restricted stock	35	35	16
Add assumed conversion of equity units	248	2,021	2,141
Add assumed exercise of stock options and stock appreciation rights	461	501	1,242
Weighted average shares outstanding - Dilutive	120,674	117,344	112,794

For the years ended December 31, 2007, 2006 and 2005, no adjustments were required in *Net earnings available for common stockholders* in the diluted EPS calculations.

The Company repurchased nil, nil and 649,343 shares of its common stock outstanding during the years ended December 31, 2007, 2006 and 2005, respectively. The 2005 repurchases substantially occurred in private off-market large-block transactions.

There were nil, nil and 87,346 "anti-dilutive" options outstanding for the years ended December 31, 2007, 2006 and 2005, respectively. At December 31, 2007, 783,445 shares of common stock were held by various rabbi trusts for certain of the Company's benefit plans. From time to time, the Company's benefit plans may purchase shares of Southern Union common stock subject to regular restrictions.

See *Note 10 – Stockholders' Equity – 2005 Equity Issuances* and *2006 Equity Issuances* for information related to the 5.75% and 5% Equity Units issued on June 11, 2003 and February 11, 2005, respectively, which had a dilutive effect on EPS for the years 2005 through 2007.

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6. Property, Plant and Equipment

The following table provides a summary of PP&E at the dates indicated:

Property, Plant and Equipment	Lives in Years (1)	December 31, 2007	December 31, 2006
		(In thousands)	
Gathering and processing plant	3-50	$ 1,678,953	$ 1,623,265
Transmission plant	36-46	1,770,742	1,400,547
Distribution plant	10-75	930,349	897,075
General - LNG	20-40	624,250	619,018
Underground storage plant	36-46	290,753	279,845
General plant and other	1-50	214,945	205,881
Plant in service (2)		5,509,992	5,025,631
Construction work in progress		377,918	178,935
		5,887,910	5,204,566
Less accumulated depreciation and amortization (2)		785,623	620,139
Net property, plant and equipment		$ 5,102,287	$ 4,584,427

(1) The composite weighted-average depreciation rates for the years ended December 31, 2007, 2006 and 2005 were 3.4 percent, 3.0 percent and 3.0 percent, respectively.

(2) Includes capitalized computerized software cost totaling:

	2007	2006
Unamortized computer software cost	$ 109,167	$ 96,556
Less accumulated amortization	45,824	41,186
Net capitalized computer software costs	$ 63,343	$ 55,370

Amortization expense of capitalized computer software costs for the years ended December 31, 2007, 2006 and 2005 was $10.6 million, $9.8 million and $11 million, respectively. Computer software costs are amortized between four and fifteen years.

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7. Goodwill

The following table displays changes in the carrying amount of goodwill, which relates solely to the Distribution segment:

Goodwill Analysis	Amounts (In thousands)
Balance as of December 31, 2004	640,547
Impairment losses	(175,000)
Balance as of December 31, 2005	465,547
Impairment losses	-
Write-off associated with sales	(376,320)
Balance as of December 31, 2006	89,227
Impairment losses	-
Balance as of December 31, 2007	$ 89,227

During 2005, the Company changed the date upon which its annual goodwill impairment assessment is performed from May 31 to November 30 to correspond with the Company's change in its fiscal year end from June 30 to December 31 and related change in the timing of completing the Company's annual operating and capital budgets. The Company believes this change is preferable. The determination of whether an impairment has occurred is based on an estimate of discounted future cash flows attributable to the Company's reporting units that have goodwill, as compared to the carrying value of those reporting units' net assets. No impairment was evident based upon the evaluations performed as of May 31, 2005 and November 30, 2005. Execution of agreements for the sale of the assets of the Company's PG Energy natural gas distribution division and the Rhode Island operations of its New England Gas Company natural gas distribution division constituted a subsequent event of the type that, under GAAP, required the Company to consider the market value indicated by the definitive sale agreements in its 2005 goodwill impairment evaluation. Accordingly, based on the fair values of these reporting units derived principally from the definitive sales agreements, a goodwill impairment charge of $175 million was recorded in the 2005 period in *Loss from discontinued operations before income taxes* in the Consolidated Statement of Operations. Goodwill of $376.3 million was written off on August 24, 2006 upon the completion of the sale of the assets of the PG Energy natural gas distribution division and the Rhode Island operations of the New England Gas Company natural gas distribution division. See *Note 19 – Discontinued Operations* for related information. All goodwill reflected in the Company's Consolidated Balance Sheet is applicable to its Distribution segment. There were no goodwill impairment indicators evident for the year ended December 31, 2007 or 2006.

8. Regulatory Assets

The Company records regulatory assets and liabilities with respect to its Distribution segment operations in accordance with Statement No. 71. Although Panhandle's natural gas transmission systems and storage operations are subject to the jurisdiction of the Federal Energy Regulatory Commission (*FERC*) in accordance with the Natural Gas Act of 1938 and Natural Gas Policy Act of 1978, it does not currently apply Statement No. 71 in accounting for its operations. In 1999, prior to its acquisition by Southern Union, Panhandle discontinued the application of Statement No. 71 primarily due to the level of discounting from tariff rates and its inability to recover specific costs.

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The following table provides a summary of regulatory assets at the dates indicated:

Regulatory Assets	December 31, 2007	December 31, 2006
	(In thousands)	
Pension and Postretirement Benefits	$ 32,889	$ 33,969
Environmental	21,782	15,571
Missouri Safety Program	5,546	8,751
Other	3,976	7,574
	$ 64,193	$ 65,865

The Company's regulatory assets at December 31, 2007 relating to Distribution segment operations that are being recovered through current rates totaled $44.8 million. The Company expects that the $19.4 million of regulatory assets not currently in rates will be included in its rates as rate cases occur in the future. The remaining recovery period associated with these assets ranged from 7 months to 93 months. The Company's regulatory assets at December 31, 2006 relating to Distribution segment operations that are being recovered through current rates totaled $30.7 million. The remaining recovery period associated with these assets ranged from 12 months to 93 months.

9. Unconsolidated Investments

A summary of the Company's unconsolidated investments at the dates indicated is as follows:

Unconsolidated Investments	December 31, 2007	December 31, 2006
	(In thousands)	
Equity investments:		
Citrus	$ 1,219,009	$ 1,233,172
Other	21,411	20,802
Investments at cost	-	775
	$ 1,240,420	$ 1,254,749

Equity Investments. Unconsolidated investments at December 31, 2007 and 2006 included the Company's 50 percent, 50 percent, 29 percent and 49.9 percent investments in Citrus, Grey Ranch, Lee 8 and PEI Power II, respectively. The Company accounts for these investments using the equity method. The Company's share of net earnings or loss from these equity investments is recorded in *Earnings from unconsolidated investments* in the Consolidated Statement of Operations.

Dividends. During the year ended December 31, 2007, Citrus paid dividends of $103.6 million to the Company. Citrus also declared a dividend in December 2007, payable in January 2008, of which the Company's share of $21.3 million is included in *Accounts receivable — affiliates* in the Consolidated Balance Sheet at December 31, 2007. The Company received this dividend on January 18, 2008.

For the eleven months ended November 30, 2006 and the year ended December 31, 2005, prior to becoming a wholly-owned subsidiary of the Company on December 1, 2006, CCE Holdings paid the Company distributions totaling $48.8 million and $15 million, respectively.

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Summarized financial information for the Company's equity investments is as follows:

	At December 31, 2007		At December 31, 2006	
	Citrus	Other Equity Investments	Citrus	Other Equity Investments
	(In thousands)			
Balance Sheet Data:				
Current assets	$ 59,644	$ 7,324	$ 64,295	$ 3,552
Non-current assets	3,049,214	38,008	3,056,818	37,633
Current liabilities	208,508	1,040	191,341	1,589
Non-current liabilities	1,697,218	1,792	1,636,671	1,802

	Year Ended December 31, 2007		Year Ended December 31, 2006		
	Citrus	Other Equity Investments	CCE Holdings (1)	Citrus (4)	Other Equity Investments
			(In thousands)		
Statement of Operations Data:					
Revenues	$ 495,513	$ 13,061	$ -	$ 37,598	$ 5,386
Operating income (loss)	283,203	4,424	(5,729)	21,201	1,157
Equity earnings	-	-	70,086 (2)	-	-
Interest expense	73,871	127	25,445	7,109	146
Earnings from discontinued operations	-	-	156,612 (3)	-	-
Net earnings	157,092	5,256	196,857	9,579	1,005

(1) The statement of operations information of CCE Holdings is through the period ended December 1, 2006. See *Note 3 - Acquisitions and Sales - CCE Holdings Transactions* for a description of the transactions that led to the Company's consolidation of CCE Holdings as of December 1, 2006.
(2) Represents equity earnings of CCE Holdings in Citrus through the period ending December 1, 2006.
(3) Earnings from discontinued operations for CCE Holdings relates primarily to the eleven months of operations of Transwestern and to the closing of the transactions on December 1, 2006 included in the Redemption Agreement, resulting in Energy Transfer's interest in CCE Holdings being exchanged for CCE Holdings' interest in Transwestern. The year ended December 31, 2006 includes a pre-tax gain of $74.8 million related to the closing of the transactions included in the Redemption Agreement. See *Note 3 - Acquisitions and Sales - CCE Holdings Transactions* for a description of the transaction.
(4) Includes Citrus results for the post-Redemption Agreement period of December 2006.

Citrus and CCE Holdings. On December 1, 2006, as more fully described in *Note 3 – Acquisitions and Sales – CCE Holdings Transactions*, the Company completed a series of transactions that resulted in it increasing its effective ownership interest in Florida Gas from 25 percent to 50 percent and eliminating its effective 50 percent ownership interest in Transwestern. Upon closing of the transactions under the Redemption Agreement on December 1, 2006, the Company became the sole owner of 100 percent of CCE Holdings, whose principal remaining asset was its 50 percent interest in Citrus. This resulted in the elimination of the Company's equity investment in CCE Holdings as of December 1, 2006 and the separate presentation of Citrus as an equity investment. Prior to December 1, 2006, Citrus was a 50 percent equity investment of CCE Holdings and included within the Company's 50 percent equity interest in CCE Holdings.

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The Company's equity investment balances include amounts in excess of the Company's share of the underlying equity of the investee of $617.4 million and $585.6 million as of December 31, 2007 and 2006, respectively. These amounts relate to the Company's 50 percent equity ownership interest in Citrus. The equity goodwill includes an allocation of $208.4 million of excess purchase cost associated with the increased interest in Citrus effectively acquired on December 1, 2006. The combined fair value amount recorded in excess of the Company's 50 percent share of the underlying Citrus equity at December 31, 2007 was as follows:

	Excess Purchase Costs (In thousands)	Amortization Period
Property, plant and equipment	$ 2,885	40 years
Capitalized software	1,478	5 years
Long-term debt (1)	(80,204)	4-20 years
Deferred taxes (1)	(6,883)	40 years
Other net liabilities	(541)	N/A
Goodwill (2)	664,609	N/A
Sub-total	581,344	
Accumulated, net accretion to equity earnings	36,102	
Net investment in excess of underlying equity	$ 617,446	

(1) Accretion of this amount increases equity earnings and accumulated net accretion.
(2) The Company's tax basis in the investment in Citrus includes equity goodwill. See "Goodwill Evaluation" below.

Other. The Company's investments in Grey Ranch, the Lee 8 partnership and PEI Power are accounted for under the equity method. The Grey Ranch Plant, LP is a 225 MMcf/d carbon dioxide treatment facility. The Lee 8 partnership operates a 3.0 Bcf natural gas storage facility in Michigan. PEI Power II is a 45-megawatt, natural gas-fired electric generation plant operated through a joint venture with Cayuga Energy in Pennsylvania.

Investments at Cost. As of December 31, 2007, the Company, either directly or through a subsidiary, owned common and preferred stock in two non-public companies, Advent Networks, Inc. (*Advent*) and PointServe, Inc. (*PointServe*), whose fair values are not readily determinable. These investments are accounted for under the cost method. Realized gains and losses on sales of these investments, as determined on a specific identification basis, are included in the Consolidated Statement of Operations when incurred, and dividends are recognized within earnings when received. Various officers, directors and employees of Southern Union either directly or through a partnership also have an equity ownership interest in Advent. As of December 31, 2007, the Company had fully reserved the related book balances for other-than-temporary impairments. See *Note 4 – Other Income and Expense Items* for additional related information.

Contingent Matters Potentially Impacting Southern Union Through the Company's Investment in Citrus.

Phase VIII Expansion. Florida Gas plans to seek FERC approval to construct an expansion to increase its natural gas capacity into Florida by approximately 800 MMcf/d (*Phase VIII Expansion*). The proposed Phase VIII Expansion includes construction of approximately 500 miles of additional large diameter pipeline and the installation of approximately 170,000 horsepower of additional compression. Pending FERC approval, which is expected in 2009, Florida Gas anticipates an in-service date of 2011, at an approximate cost of $2 billion. Florida Gas has signed a 25-year agreement with Florida Power and Light Company, a wholly–owned subsidiary of FPL Group, Inc., for 400 MMcf/d of capacity.

On February 5, 2008, Citrus entered into a $500 million unsecured construction and term loan agreement (*Citrus Credit Agreement*) with a wholly-owned subsidiary of FPL Group Capital Inc, which is a wholly–owned subsidiary of FPL Group, Inc. Citrus will contribute the proceeds of this loan to Florida Gas in order to finance a portion of the Phase VIII Expansion.

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The Citrus Credit Agreement provides for a single $500 million draw after Florida Gas' receipt of a certificate from the FERC authorizing construction of the Phase VIII Expansion and Citrus' satisfaction of customary conditions precedent, which are expected to be met in the second half of 2009. On or before the Phase VIII Expansion in-service date, the construction loan will convert to an amortizing 20-year term loan with a $300 million balloon payment at maturity. The loan requires semi-annual payments of principal beginning five years and six months after the conversion to a term loan. The Citrus Credit Agreement provides for interest on the outstanding principal amount at the rate of six-month LIBOR plus 535 basis points prior to conversion to a term loan and at the twenty-year treasury rate plus 535 basis points after conversion to a term loan. The loan is not guaranteed by Florida Gas and does not include a prepayment option. The Citrus Credit Agreement contains certain customary representations, warranties and covenants and requires the execution of a negative pledge agreement by Florida Gas.

Environmental Matters. Florida Gas is responsible for environmental remediation of contamination resulting from past releases of hydrocarbons and chlorinated compounds at certain sites on its gas transmission systems. Florida Gas is implementing a program to remediate such contamination. Activities vary with site conditions and locations, the extent and nature of the contamination, remedial requirements and complexity. The ultimate liability and total costs associated with these sites will depend upon many factors. These sites are generally managed in the normal course of business or operations. The Company believes the outcome of these matters will not have a material adverse effect on its consolidated financial position, results of operations or cash flows.

Spill Prevention, Control and Countermeasure Rules (SPCC). In May 2007, the U.S. EPA extended the SPCC rule compliance dates until July 1, 2009 permitting owners and operators of facilities to prepare or amend and implement SPCC Plans in accordance with previously enacted modifications to the regulations. In October of 2007, the U.S. EPA proposed amendments to the SPCC rules with the stated intention of providing greater clarity, tailoring requirements, and streamlining requirements. The Company is currently reviewing the impact of the modified regulations on its operations and may incur costs for tank integrity testing, alarms and other associated corrective actions as well as potential upgrades to containment structures. Costs associated with such activities cannot be estimated with certainty at this time, but the Company believes such costs will not have a material adverse effect on its consolidated financial position, results of operations or cash flows.

CCE Holdings' Goodwill Evaluation. CCE Holdings applied the purchase method of accounting for its acquisition of CrossCountry Energy on November 17, 2004. Goodwill associated with CCE Holdings' equity investment in Citrus accounted for under APB 18 was approximately $664.6 million and $642.2 million at December 31, 2007 and 2006, respectively. The amounts recorded at December 31, 2007 includes final purchase price allocations related to the December 1, 2006 redemption of Transwestern and the resulting increase in Southern Union's equity interest in Citrus. See *Note 3 – Acquisitions and Sales – CCE Holdings Transactions*.

Regulatory Assets and Liabilities. Florida Gas is subject to regulation by certain state and federal authorities. Florida Gas has accounting policies that conform to Statement No. 71 and are in accordance with the accounting requirements and ratemaking practices of applicable regulatory authorities. Management's assessment for Florida Gas of the probability of its recovery or pass through of regulatory assets and liabilities requires judgment and interpretation of laws and regulatory commission orders. If, for any reason, Florida Gas ceases to meet the criteria for application of regulatory accounting treatment for all or part of its operations, the regulatory assets and liabilities related to those portions ceasing to meet such criteria would be eliminated from its consolidated balance sheet, resulting in an impact to the Company's share of its equity earnings. Florida Gas' regulatory asset and liability balances at December 31, 2007 were $19.2 million and $14.8 million, respectively.

Federal Pipeline Integrity Rules. On December 15, 2003, the U.S. Department of Transportation issued a final rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the regulation defines as "high consequence areas" (*HCAs*). This rule resulted from the enactment of the Pipeline Safety Improvement Act of 2002. The rule requires operators to have identified HCAs along their pipelines by December 2004 and to have begun baseline integrity assessments, comprised of in-line inspection (smart pigging), hydrostatic testing or direct assessment, by June 2004. Operators were required to rank the risk of their pipeline segments containing

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HCAs and to complete assessments on at least 50 percent of the segments using one or more of these methods by December 2007. Assessments will generally be conducted on the higher risk segments first, with the balance being completed by December 2012. As of December 31, 2007, Florida Gas completed 62 percent of the risk assessments. In addition, some system modifications will be necessary to accommodate the in-line inspections. All systems operated by the Company will be compliant with the rule; however, while identification and location of all HCAs has been completed, it is not practicable to determine with certainty the total scope of required remediation activities prior to completion of the assessments and inspections. For Florida Gas, the required modifications and inspections are currently estimated to be in the range of approximately $21 million to $28 million per year through 2012.

Florida Gas Pipeline Relocation Costs. The Florida Department of Transportation, Florida's Turnpike Enterprise (*FDOT/FTE*) has various turnpike widening projects that have impacted or may, over time, impact one or more of Florida Gas' mainline pipelines co-located in FDOT/FTE rights-of-way. The first phase of the turnpike project includes replacement of approximately 11.3 miles of its existing 18- and 24- inch pipelines located in FDOT/FTE right-of-way in Florida. Estimated cost of such replacement would be $110 million. Florida Gas is also in discussions with the FDOT/FTE related to additional projects that may affect Florida Gas' 18- and 24-inch pipelines within FDOT/FTE rights-of-way. The total miles of pipe that may ultimately be affected by all of the FDOT/FTE widening projects, and any associated relocation and/or right-of-way costs, cannot be determined at this time.

Under certain conditions, existing agreements between Florida Gas and the FDOT/FTE require the FDOT/FTE to provide any new rights-of-way needed for relocation of the pipelines and for Florida Gas to pay for rearrangement or relocation costs. Under certain other conditions, Florida Gas may be entitled to reimbursement for the costs associated with relocation, including construction and right-of-way costs. On January 25, 2007, Florida Gas filed a complaint against the FDOT/FTE in the Seventeenth Judicial Circuit, Broward County, Florida, seeking relief with respect to three specific sets of FDOT/FTE widening projects in Broward County. The complaint seeks damages for breach of easement and relocation agreements for the one set of projects on which construction has already commenced, and injunctive relief as well as damages for the two other sets of projects on which construction has yet to commence. The FDOT/FTE filed an amended answer and counterclaim against Florida Gas on February 5, 2008 in the Broward County action. The counterclaim alleges Florida Gas is subject to estoppel and breach of contract regarding removal from service of the existing pipelines on the project currently under construction and seeks a declaratory judgment that Florida Gas is responsible for all relocation costs and is not entitled to workspace and uniform minimum area precluding FDOT/FTE activity. On February 14, 2008, the case was transferred to the Broward County Complex Business Civil Division 07. As a result, the March 10, 2008 hearing on the motion by Florida Gas for a temporary injunction enjoining the FDOT/FTE interference with the pipelines of Florida Gas will be rescheduled. On April 24, 2007, the FDOT/FTE filed a complaint against Florida Gas in the Ninth Judicial Circuit, Orange County, Florida, seeking a declaratory judgment that, under existing agreements, Florida Gas is liable for the costs of relocation associated with such projects and is not entitled to certain other rights. On August 7, 2007, the Orange County Court granted a motion by Florida Gas to abate and stay the Orange County action.

On October 24, 2007, Florida Gas filed a complaint in the US District Court of the Northern District of Florida, Tallahassee Division, against Stephanie C. Kopelousos (*Kopelousos*) in her official capacity as the Secretary of the Florida Department of Transportation, seeking to enjoin Kopelousos from violating federal law in connection with construction of the FDOT/FTE Golden Glades project, a new toll plaza in Miami-Dade County, Florida. Florida Gas seeks a declaratory judgment that certain Florida statutes are preempted by federal law to the extent such state statutes purport to regulate the abandonment or relocation schedule for the federally regulated pipelines of Florida Gas and prospective preliminary and permanent injunctive relief enjoining Kopelousos from proceeding with construction on the Golden Glades project over and around such pipelines. Kopelousos has filed a motion to dismiss and Florida Gas has responded. Based upon representations by the FDOT/FTE that work would not begin on the Golden Glades project until 2013, the parties entered into a joint stipulation of dismissal without prejudice on February 15, 2008.

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Should Florida Gas be denied reimbursement by the FDOT/FTE for any possible relocation expenses, such costs are expected to be covered by operating cash flows and additional borrowings. Florida Gas expects to seek rate recovery at FERC for all reasonable and prudent costs incurred in relocating its pipelines to accommodate the FDOT/FTE to the extent not reimbursed by the FDOT/FTE. There can be no assurance that Florida Gas will be successful in obtaining complete reimbursement for any such relocation costs from the FDOT/FTE or from its customers or that the timing of reimbursement will fully compensate Florida Gas for its costs.

Citrus Trading Litigation. On January 29, 2007, Citrus Trading, Citrus, Southern Union and El Paso Corporation (collectively, *Citrus Parties*) entered into a settlement regarding litigation with Spectra Energy LNG Sales, Inc., formerly known as Duke Energy LNG Sales, Inc. (*Duke*), and its parent company, Spectra Energy Corporation (collectively, *Spectra*), whereby Spectra agreed to pay $100 million to Citrus Trading. The litigation related to a natural gas purchase contract between Citrus Trading and Duke that had been terminated in 2003. Citrus recorded a net gain of $15 million in the first quarter of 2007, $7.5 million of which is included in *Earnings from unconsolidated investments* in the Consolidated Statement of Operations. The Citrus Parties also entered into a settlement on January 29, 2007 with Enron Corp. pursuant to which CCE Holdings' obligation to remit to Enron Corp. certain proceeds of any Duke settlement was reduced, resulting in a $7.6 million gain recorded in *Earnings from unconsolidated investments* in the Consolidated Statement of Operations.

Citrus Enron Bankruptcy Receivable. Citrus previously filed bankruptcy related claims against an Enron-affiliated bankrupt company. The parties reached a settlement in the amount of $22.7 million on the allowed claim, which was approved by the bankruptcy court in March 2007. Citrus fully reserved for the amounts in 2001 and sold the receivable claim in the second quarter of 2007 to a third-party for $11.4 million, resulting in a gain. *Earnings from unconsolidated investments* includes $5.7 million of the gain ($3.6 million, net of tax), representing the Company's 50 percent equity share of the gain.

Litigation.

Jack Grynberg. Jack Grynberg, an individual, has filed actions against a number of companies, including Florida Gas, alleging mis-measurement of gas volumes and Btu content, resulting in lower royalties to mineral interest owners. For additional information related to these filed actions, see *Note 18 – Commitments and Contingencies – Litigation.*

10. Stockholders' Equity

Dividends. The table below presents the amount of cash dividends declared and paid in the respective periods:

Shareholder Record Date	Date Paid	Amount Per Share	Amount Paid (In thousands)
December 28, 2007	January 11, 2008	$ 0.15	$ 17,999
September 28, 2007	October 12, 2007	0.10	11,997
June 29, 2007	July 13, 2007	0.10	11,995
March 30, 2007	April 13, 2007	0.10	11,977
December 29, 2006	January 12, 2007	$ 0.10	$ 11,961
September 29, 2006	October 13, 2006	0.10	11,956
June 30, 2006	July 14, 2006	0.10	11,197
March 31, 2006	April 14, 2006	0.10	11,175

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For the year ended December 31, 2006, the Company reduced *Retained earnings (deficit)* and *Premium on capital stock* in the Consolidated Statement of Stockholders' Equity and Comprehensive Income by $19.9 million (to the extent that retained earnings were available) and $26.4 million, respectively.

Prior to 2006, the Company distributed common stock dividends in lieu of cash dividend payments. On September 1, 2005, the Company distributed its then annual five percent common stock dividend to stockholders of record on August 22, 2005. Unless otherwise stated, all per share and share data in this report for periods prior to 2006 have been restated to give effect to the stock dividend.

Under the terms of the indenture governing its Senior Notes, Southern Union may not declare or pay any cash or asset dividends on its common stock (other than dividends and distributions payable solely in shares of its common stock or in rights to acquire its common stock) or acquire or retire any shares of its common stock, unless no event of default exists and certain financial ratio requirements are satisfied. Currently, the Company is in compliance with these requirements and, therefore, the Senior Note indenture does not prohibit the Company from paying cash dividends.

Stock Award Plans. On May 9, 2005, the stockholders of the Company adopted the Southern Union Company Amended and Restated 2003 Stock and Incentive Plan (*Amended 2003 Plan*). The Amended 2003 Plan allows for awards in the form of stock options (either incentive stock options or non-qualified options), SARs, stock bonus awards, restricted stock, performance units or other equity-based rights. The persons eligible to receive awards under the Amended 2003 Plan include all of the employees, directors, officers and agents of, and other service providers to, the Company and its affiliates and subsidiaries. The Amended 2003 Plan provides that each non-employee director will receive annually a restricted stock award, or at the election of the non-employee director options having an equivalent value, which will be granted at such time or times as the compensation committee shall determine. Under the Amended 2003 Plan: (i) no participant may receive in any calendar year awards covering more than 500,000 shares; (ii) the exercise price for a stock option may not be less than 100 percent of the fair market value of the common stock on the date of grant; and (iii) no award may be granted more than ten years after the date of the Amended 2003 Plan.

On May 2, 2006, the stockholders of the Company adopted the Second Amended and Restated 2003 Plan (*Second Amended 2003 Plan*), which included the following changes to the Amended 2003 Plan:

- An increase from 7,000,000 to 9,000,000 in the aggregate number of shares of stock that may be issued under the plan;
- An increase from 725,000 to 1,500,000 in the total number of shares of stock that may be issued pursuant to stock awards, performance units and other equity-based rights; and
- An increase from 4,000 to 5,000 in the maximum number of shares of restricted common stock that each non-employee director is eligible to receive annually.

On July 1, 2005, pursuant to the respective separation agreements between the Company and each of its former Vice Chairman of the Board of Directors and former Chief Financial Officer, the Company modified the terms of approximately 307,000 options to purchase its common stock that had previously been granted to and were exercisable by these executives under the Company's 1992 Long-Term Stock Incentive Plan (*1992 Plan*) and Amended 2003 Plan. As a result of the modification and re-valuation of the options as of July 1, 2005, the Company recorded $3.8 million of non-cash compensation expense during the quarter ended September 30, 2005. All of these options were exercised as of December 31, 2006.

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The Company maintains its 1992 Plan, under which options to purchase 8,491,540 shares of its common stock were authorized to be granted until July 1, 2002 to officers and key employees at prices not less than the fair market value on the date of grant. The 1992 Plan allowed for the granting of SARs, dividend equivalents, performance shares and restricted stock. Options granted under the 1992 Plan are exercisable for ten years from the date of grant or such lesser period as may be designated for particular options, and become exercisable after a specified period of time from the date of grant in cumulative annual installments. Options typically vest at the rate of 20 percent per year, but may vest over a longer or shorter period as designated for a particular option grant. At December 31, 2006, there were no shares available for future option grants under the 1992 Plan.

In connection with the acquisition of Pennsylvania Enterprises, Inc., the Company adopted the Pennsylvania Division 1992 Stock Option Plan (*Pennsylvania Option Plan*) and the Pennsylvania Division Stock Incentive Plan (*Pennsylvania Incentive Plan* and, together with the Pennsylvania Option Plan, *the Pennsylvania Plans*). At December 31, 2007, no options were outstanding and no additional options will be granted under the Pennsylvania Plans. During the year ended December 31, 2005, options exercised under the Pennsylvania Option Plan were 466,127. During the year ended December 31, 2005, 139,837 and 91,831 options were exercised and canceled, respectively, under the Pennsylvania Incentive Plan.

For more information on share-based awards, see *Note 24 – Share-Based Compensation*.

2006 Equity Issuances. On August 16, 2006, the Company received $125 million from the issuance of 7,413,074 shares of common stock in conjunction with the remarketing of its 2.75% Senior Notes and the consummation of the forward stock purchase contracts that were issued with the 2.75% Senior Notes as part of the June 2003 5.75% Equity Units issuance. See *Note 13 – Debt Obligations – Long-Term Debt*.

2005 Equity Issuances. On February 11, 2005, Southern Union issued 2,000,000 of its 5% Equity Units at a public offering price of $50 per unit, resulting in net proceeds to the Company, after underwriting discounts and commissions and other transaction related costs, of $97.4 million. Southern Union used the proceeds to repay the balance of the bridge loan used to finance a portion of its investment in CCE Holdings and to repay borrowings under its credit facilities. Each 5% Equity Unit consisted of a $1/20^{th}$ interest in a $1,000 principal amount of Southern Union's 4.375% Senior Notes due 2008 (see *Note 13 – Debt Obligations*) and a forward stock purchase contract that obligated the holder to purchase Southern Union common stock on February 16, 2008, at a price based on the preceding 20-day average closing price (subject to a minimum and maximum conversion price per share of $22.74 and $28.42, respectively, which were subject to adjustments for future stock splits or stock dividends). On February 19, 2008, the Company issued 3,693,240 shares of its common stock upon the consummation of the forward purchase contracts. The 5% Equity Units carried a total annual coupon of 5.00 percent (4.375 percent annual face amount of the senior notes plus 0.625 percent annual contract adjustment payments). The present value of the 5% Equity Units' contract adjustment payments was initially charged to stockholders' equity, with an offsetting credit to liabilities. The liability was accreted over three years by interest charges to the Consolidated Statement of Operations. Before the issuance of Southern Union's common stock upon settlement of the purchase contracts, the 5% Equity Units were reflected in the Company's diluted EPS calculations using the treasury stock method. See *Note 25 – Subsequent Event*.

On February 9, 2005, Southern Union issued 14,913,042 shares of common stock at a public offering price of $23.00 per share, resulting in net proceeds, after underwriting discounts and commissions of $332.6 million. Southern Union used the net proceeds to repay a portion of the bridge loan used to finance a portion of its investment in CCE Holdings.

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11. Derivative Instruments and Hedging Activities

Interest Rate Swaps. The Company uses interest rate swaps to reduce interest rate risks and to manage interest expense. By entering into these agreements, the Company converts floating-rate debt into fixed-rate debt, or alternatively converts fixed-rate debt to floating-rate debt. Interest differentials paid or received under the swap agreements are reflected as an adjustment to interest expense. These interest rate swaps are financial derivative instruments that qualify for hedge treatment. The notional amounts of the interest rate swaps are not exchanged and do not represent exposure to credit loss. In the event of default by a counterparty, the risk in these transactions is the cost of replacing the agreements at current market rates. For the years ended December 31, 2007, 2006 and 2005, there was no swap ineffectiveness. At December 31, 2007, $17.1 million is included in *Deferred Credits* in the Consolidated Balance Sheet related to the fixed-rate interest rate swaps on the $455 million Term Loan due 2012. As of December 31, 2007, approximately $3.2 million of net after-tax losses in *Accumulated other comprehensive loss* will be amortized into interest expense during the next twelve months related to the swap agreements. Current market pricing models were used to estimate fair values of interest rate swap agreements.

Treasury Rate Locks. The Company enters into treasury rate locks to hedge the changes in cash flows of anticipated interest payments from changes in treasury rates prior to the issuance of new debt instruments. The Company accounts for the treasury rate locks as cash flow hedges. At December 31, 2007, $1.7 million is included in *Prepayments and Other* in the Consolidated Balance Sheet related to the treasury rate locks entered into during 2007. As of December 31, 2007, approximately $1 million of net after-tax losses in *Accumulated other comprehensive loss* will be amortized into interest expense during the next twelve months related to these treasury rate locks.

Distribution Segment

Economic Hedging Activities. During 2007, 2006 and 2005, the Company entered into natural gas commodity swaps and collars to mitigate price volatility of natural gas passed through to utility customers in the Distribution Segment. The cost of the derivative products and the settlement of the respective obligations are recorded through the gas purchase adjustment clause as authorized by the applicable regulatory authority and therefore do not impact earnings. The fair values of the contracts are recorded as an adjustment to a regulatory asset or liability in the Consolidated Balance Sheet. As of December 31, 2007 and 2006, the fair values of the contracts, which expire at various times through December 2009, are included in the Consolidated Balance Sheet as assets and liabilities, respectively, with matching adjustments to deferred cost of gas of $22.3 million and $19 million, respectively.

Gathering and Processing Segment

The Company markets natural gas and NGLs in its Gathering and Processing segment and manages associated commodity price risks using derivative financial instruments. These instruments involve not only the risk of transacting with counterparties and their ability to meet the terms of the contracts but also the risk associated with unmatched positions and market fluctuations. The Company is required to record derivative financial instruments at fair value, which is determined by commodity exchange prices, over-the-counter quotes, volatility, time value, counterparty credit and the potential impact on market prices of liquidating positions in an orderly manner over a reasonable period of time under current market conditions.

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Economic Hedging Derivatives. The Company uses various derivative financial instruments to manage commodity price risk and to take advantage of pricing anomalies among derivative financial instruments related to natural gas and NGLs. The Company uses a combination of crude oil puts, NGL gross processing spread puts, fixed-price physical forward contracts, exchange-traded futures and options, and fixed or floating index and basis swaps to manage sales commodity price risk. These economic hedge derivative financial instruments allow the Company to preserve value and protect margins because changes in the value of the derivative financial instruments are effective in offsetting changes in the physical market and reducing basis risk. Basis risk exists primarily due to price differentials between cash market delivery locations and futures contract delivery locations. For the year ended December 31, 2007 and the ten-months ended December 31, 2006, gains of $1.2 million and $1.2 million, respectively, were recorded for the economic hedging activities. At December 31, 2007 and 2006, the net asset derivative balance was $6.7 million and $10.3 million, respectively.

The Company realizes NGL and/or natural gas volumes from its contractual arrangements associated with gas processing services it provides. The Company utilizes various economic hedge techniques to manage its price exposure of Company owned volumes, including processing spread puts and natural gas swaps. Expected NGL and/or natural gas volumes compared to the actual volumes sold and the effectiveness of the associated economic hedges utilized by the Company can be unfavorably impacted by:

- Processing plant outages;
- Higher than anticipated FF&U efficiency levels;
- Impact of commodity prices in general;
- Lower than expected recovery of NGLs from the residue gas stream; and
- Lower than expected recovery of natural gas volumes to be processed.

For the purpose of reducing its processing spread exposure, the Company purchased put options for the period February 1, 2008 through December 31, 2008. The put options reduce its processing spread exposure on 11,075 MMBtu/day, or approximately 25 percent of the Company's expected NGLs sales volumes based on 2007 historical processing trends. The put options set a floor for the Company’s processing spread at $8.15 per MMBtu for such volumes. The cost of the December 2007 transaction was $5.2 million, or $1.41 per MMBtu.

Additionally, in February 2008, for the period March 1, 2008 through December 31, 2008, the Company entered into various natural gas swaps which have reduced its commodity price exposure related to 30,000 MMBtu/day. The natural gas swaps have effectively established an average fixed index price at locations where we sell natural gas, at the “basis adjusted price” of $8.28 per MMBtu for the related period. The combination of the processing spread put option with an equal MMBtu portion of the natural gas swap effectively establishes a floor of $15.02 per MMBtu for 25 percent of the Company’s expected NGL sales volumes as noted above. In February 2008, the Company also entered into natural gas swaps associated with 10,000 MMBtu/day for the period January 1, 2009 through December 31, 2009, fixing the 2009 basis adjusted sales price of such volumes at $8.19 per MMBtu.

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Accounting Hedges Designated as Cash Flow Hedges. In accordance with Statement No. 133, the Company designated its natural gas, propane and ethane put options as accounting (cash flow) hedges. The Company used such accounting hedges to manage its commodity price risk and reduce fluctuations in operating cash flows. All of the Company's put options on its natural gas, propane and ethane products expired as of December 31, 2007.

The table below summarizes the financial statement impact of hedged put options related to natural gas and NGLs the Company had in place during the respective periods.

	Years Ended December 31,	
	2007	2006
	(In thousands)	
Change in fair value of commodity hedges - increase (decrease) in *Accumulated other comprehensive loss,* excluding tax expense effect of $(775) and $7,556, respectively	$ (2,054)	$ 19,826
Reclassification of unrealized gain on commodity hedges - increase of *Operating Revenues*, excluding tax expense effect of $2,425 and $4,266, respectively	6,422	11,350
Loss realized upon cash settlement - decrease of *Operating revenues*	718	45
Loss on ineffectiveness of commodity hedges	-	1,634
Cash realized on settlement of commodity hedges	35,374	74,214

At December 31, 2007 and 2006, the Company reported in the Consolidated Balance Sheet in *Prepayments and other assets*, derivative asset balances for its hedged put options of nil and $38.1 million, respectively. During 2007, the Company reclassified all previously deferred gains included in *Accumulated other comprehensive loss* into earnings.

12. Preferred Securities

On October 8, 2003, the Company issued 9,200,000 depositary shares, each representing a 1/10th interest in a share of its 7.55% Noncumulative Preferred Stock, Series A (Liquidation Preference $250 Per Share) (*Preferred Stock*), at the public offering price of $25 per share, or $230 million in the aggregate. The total net proceeds were used to repay debt under the Company's revolving credit facilities. The Company may redeem the Preferred Stock beginning on October 8, 2008.

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13. Debt Obligations

The following table sets forth the debt obligations of Southern Union and Panhandle under their respective notes, debentures and bonds at the dates indicated:

	December 31, 2007		December 31, 2006	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In thousands)			
Long-Term Debt Obligations:				
Southern Union				
7.60% Senior Notes due 2024	$ 359,765	$ 378,473	$ 359,765	$ 384,948
8.25% Senior Notes due 2029	300,000	336,090	300,000	371,367
7.24% to 9.44% First Mortgage Bonds due 2020 to 2027	19,500	19,500	19,500	19,500
4.375% Senior Notes due 2008	100,000	100,000	100,000	100,000
6.15% Senior Notes due 2008	125,000	124,538	125,000	125,655
7.20% Junior Subordinated Notes due 2066	600,000	590,280	600,000	598,572
	1,504,265	1,548,881	1,504,265	1,600,042
Panhandle				
2.75% Senior Notes due 2007	-	-	200,000	200,000
4.80% Senior Notes due 2008	300,000	298,140	300,000	300,000
6.05% Senior Notes due 2013	250,000	252,650	250,000	251,053
6.20% Senior Notes due 2017	300,000	297,240	-	-
6.50% Senior Notes due 2009	60,623	62,132	60,623	61,721
8.25% Senior Notes due 2010	40,500	43,396	40,500	43,180
7.00% Senior Notes due 2029	66,305	65,198	66,305	71,947
Term Loan due 2007	-	-	255,626	255,626
Term Loan due 2012 (1)	412,220	412,220	465,000	465,000
Term Loan due 2012	455,000	455,000	-	-
Net premiums on long-term debt	6,093	6,093	9,613	9,613
	1,890,741	1,892,069	1,647,667	1,658,140
Total Long-Term Debt Obligations	3,395,006	3,440,950	3,151,932	3,258,182
Credit Facilities	123,000	123,000	100,000	100,000
Total consolidated debt obligations	3,518,006	$ 3,563,950	3,251,932	$ 3,358,182
Less fair value swaps of Panhandle	-		1,265	
Less current portion of long-term debt (2), (3)	434,680		461,011	
Less short-term debt	123,000		100,000	
Total consolidated long-term debt obligations	$ 2,960,326		$ 2,689,656	

(1) At December 31, 2006, this Term Loan was due in 2008. See the following *LNG Holdings Term Loans* discussion for information related
to the extension of the maturity date from April 4, 2008 to June 29, 2012.

(2) Includes nil and $1.3 million of fair value of swaps related to debt classified as current at December 31, 2007 and 2006, respectively.

(3) Excludes $100 million related to the 4.375% Senior Notes that were remarketed in February 2008 resulting in a change of the

maturity
date to February 16, 2010. See Note 25 — Subsequent Event for additional related information.

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Long-Term Debt.

Southern Union has $3.4 billion of long-term debt, including net premiums of $6.1 million, recorded at December 31, 2007, of which $434.7 million is current. Debt of $2.98 billion is at fixed rates ranging from 4.38 percent to 9.44 percent. Southern Union also has floating rate debt totaling $412.2 million, bearing an interest rate of 5.37 percent as of December 31, 2007.

As of December 31, 2007, the Company has scheduled long-term debt payments, excluding credit facility payments and net premiums on debt, as follows:

	2008	2009	2010	2011	2012	2013 and thereafter
			(In thousands)			
Southern Union Company	$ 125,000	$ -	$ 100,000	$ -	$ -	$ 1,279,265
Panhandle	309,831	60,623	40,500	-	857,389	616,305
Total	$ 434,831	$ 60,623	$ 140,500	$ -	$ 857,389	$ 1,895,570

Each note, debenture or bond is an obligation of Southern Union or a unit of Panhandle, as noted above. Panhandle's debt is non-recourse to Southern Union. All debts that are listed as debt of Southern Union are direct obligations of Southern Union. None of the Company's long-term debt is cross-collateralized and most of its long-term debt obligations contain cross-default provisions.

6.20% Senior Notes. On October 26, 2007, PEPL issued $300 million in senior notes due November 1, 2017 with an interest rate of 6.20 percent (*6.20% Senior Notes*). In connection with the issuance of the 6.20% Senior Notes, the Company incurred underwriting and discount costs of approximately $2.7 million. The debt was priced to the public at 99.741 percent, resulting in $297.3 million in proceeds to the Company. The proceeds were initially used to repay approximately $246 million outstanding under the credit facilities. The remaining proceeds of $51.3 million were invested by the Company and subsequently utilized to fund working capital obligations.

LNG Holdings Term Loans. On March 15, 2007, LNG Holdings, as borrower, and PEPL and Trunkline LNG, as guarantors, entered into a $455 million unsecured term loan facility due March 13, 2012 (*2012 Term Loan*). The interest rate under the 2012 Term Loan is a floating rate tied to a LIBOR rate or prime rate at the Company's option, in addition to a margin tied to the rating of PEPL's senior unsecured debt. The proceeds of the 2012 Term Loan were used to repay approximately $455 million in existing indebtedness that matured in March 2007, including the $200 million 2.75% Senior Notes and the LNG Holdings $255.6 million Term Loan. LNG Holdings has entered into interest rate swap agreements that effectively fixed the interest rate applicable to the 2012 Term Loan at 4.98 percent plus a credit spread of 0.625, based upon PEPL's credit rating for its senior unsecured debt. See *Note 11 – Derivative Instruments and Hedging Activities – Interest Rate Swaps* for information regarding interest rate swaps.

In connection with the December 1, 2006 closing of the Redemption Agreement, LNG Holdings, as borrower, and PEPL and CrossCountry Citrus, LLC, as guarantors, entered into a $465 million unsecured term loan facility due April 4, 2008 (*2006 Term Loan*). On June 29, 2007, the parties entered into an amended and restated term loan facility (*Amended Credit Agreement*). The Amended Credit Agreement extended the maturity of the 2006 Term Loan from April 4, 2008 to June 29, 2012, and decreased the interest rate from LIBOR plus 87.5 basis points to LIBOR plus 55 basis points, based upon the current credit rating of PEPL's senior unsecured debt. The balance of the term loan facility at December 31, 2007 was $412.2 million.

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Junior Subordinated Notes. On October 23, 2006, the Company issued $600 million in junior subordinated notes due November 1, 2066 with an initial fixed interest rate of 7.20 percent (*Junior Subordinated Notes*). In connection with the issuance of the Junior Subordinated Notes, the Company incurred underwriting and discount costs of approximately $9 million. The debt was priced to the public at 99.844 percent, resulting in $590.1 million in proceeds to the Company. The outstanding Sid Richardson Bridge Loan balance of approximately $525 million was retired using the proceeds from the debt offering and the remaining approximately $65 million of debt offering proceeds were used to pay down a portion of the Company's credit facilities.

Pursuant to the terms of the Junior Subordinated Notes, the Company may at its discretion defer interest payments for up to ten consecutive years at a time. The Company may make such election on more than one occasion, provided that payment of all previously deferred interest has been made and the deferral period does not extend beyond the November 1, 2066 maturity date, at which time all deferred interest would become due and payable.

The Company has entered into a covenant agreement for the benefit of holders of a designated series of indebtedness, other than the Junior Subordinated Notes, that it will not redeem or repurchase the Junior Subordinated Notes, in whole or in part, on or before October 31, 2036, unless, subject to certain limitations, during the 180 days prior to the date of that redemption or repurchase, the Company has received an equal or greater amount of net cash proceeds from the sale of common stock or other qualifying securities.

Remarketing Obligation. In June 2003, the Company issued $125 million aggregate principal amount of 2.75% senior notes due August 16, 2006 in conjunction with the issuance of its 5.75% equity units. Each equity unit was comprised of a senior note in the principal amount of $50 and a forward purchase contract under which the equity unit holder agreed to purchase shares of Southern Union common stock on August 16, 2006 at a price based on the preceding 20-trading day average closing price subject to a minimum conversion price per share of $13.82 (in which case 9.044 million shares would be issued) and a maximum conversion price of $16.86 (in which case 7.413 million shares would be issued). On August 16, 2006, the Company remarketed the 2.75% senior notes, which are now due August 16, 2008.

As part of the remarketing, the interest rate on the senior notes was reset to 6.15 percent. The senior notes paid interest in arrears on each February 16 and August 16, which commenced on February 16, 2007. The senior notes will mature on August 16, 2008. The senior notes are unsecured and rank equally with all of the Company's other unsecured and unsubordinated indebtedness from time to time outstanding.

Short-Term Debt Obligations, Excluding Current Portion of Long-Term Debt.

Credit Facilities. On September 29, 2005, Southern Union entered into a Fourth Amended and Restated Revolving Credit Facility in the amount of $400 million (*Long-Term Facility*). The Long-Term Facility has a five-year term and matures on May 28, 2010. The Long-Term Facility replaced the Company's May 28, 2004 long-term credit facility in the same amount. Borrowings under the Long-Term Facility are available for Southern Union's working capital and letter of credit requirements and for other general corporate purposes. The Long-Term Facility is subject to a commitment fee based on the rating of the Company's senior unsecured notes (*Senior Notes*). As of December 31, 2007, the commitment fees were an annualized 0.15 percent. The Company has an additional $30 million of availability under uncommitted line of credit facilities with various banks.

Balances of $123 million and $100 million were outstanding under the Company's credit facilities at effective interest rates of 5.82 percent and 6.02 percent at December 31, 2007 and 2006, respectively. The Company classifies its borrowings under the credit facilities due May 28, 2010 as short-term debt, as the individual borrowings are generally for periods of 15 to 180 days. At maturity, the Company may (i) retire the outstanding balance of each borrowing with available cash on hand and/or proceeds from a new borrowing, or (ii) at the Company's option, extend the borrowing's maturity date for up to an additional 90 days. As of February 22, 2008, there was a balance of $45 million outstanding under the Company's credit facilities, with an effective interest rate of 3.77 percent.

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Sid Richardson Bridge Loan. On March 1, 2006, Southern Union acquired Sid Richardson Energy Services for approximately $1.6 billion in cash. The acquisition was funded under a bridge loan facility in the amount of $1.6 billion that was entered into on March 1, 2006 between the Company and a group of banks as lenders. On August 24, 2006, the Company applied approximately $1.1 billion in net proceeds from the sales of the assets of its PG Energy natural gas distribution division and the Rhode Island operations of its New England Gas Company natural gas distribution division to repayment of the Sid Richardson Bridge Loan. See *Note 19 – Discontinued Operations* for related information. On October 23, 2006, the Company retired the remainder of the Sid Richardson Bridge Loan using a portion of the proceeds received from the Company's issuance of $600 million in Junior Subordinated Notes.

Interest expense totaling $49.2 million related to the Sid Richardson Bridge Loan was incurred during 2006 at an average interest rate of 5.72 percent. Debt issuance costs totaling $9.2 million were incurred in connection with the financing of the acquisition, of which $7.8 million was related to the Sid Richardson Bridge Loan and $1.4 million was related to the placement of permanent financing. The Company fully amortized the $7.8 million of the Sid Richardson Bridge Loan debt issuance cost to interest expense during 2006.

Other Debt Activity.

In conjunction with the Company's sale of the assets of its PG Energy natural gas distribution division, $15 million of the Company's First Mortgage Bonds were repaid. National Grid USA assumed $77 million of the Company's First Mortgage Bonds in conjunction with its purchase of the Rhode Island operations of the Company's New England Gas Company natural gas distribution division. See *Note 19 – Discontinued Operations* for related information.

On July 14, 2005, the Company amended an existing short-term bank note to increase the principal amount thereunder from $15 million to $65 million in order to provide additional liquidity. The note is repayable upon demand. The Company borrowed $50 million under the note on July 19, 2005 at an initial interest rate of 4.54 percent, which was based on LIBOR plus 70 basis points. The Company repaid the $50 million additional principal amount on April 17, 2006.

Restrictive Covenants. The Company is not party to any lending agreement that would accelerate the maturity date of any obligation due to a failure to maintain any specific credit rating. Certain covenants exist in certain of the Company's debt agreements that require the Company to maintain a certain level of net worth, to meet certain debt to total capitalization ratios and to meet certain ratios of earnings before depreciation, interest and taxes to cash interest expense. A failure by the Company to satisfy any such covenant would give rise to an event of default under the associated debt, which could become immediately due and payable if the Company did not cure such default within any permitted cure period or if the Company did not obtain amendments, consents or waivers from its lenders with respect to such covenants.

The Company's restrictive covenants include restrictions on debt levels, restrictions on liens securing debt and guarantees, restrictions on mergers and on the sales of assets, capitalization requirements, dividend restrictions, cross default and cross-acceleration and prepayment of debt provisions. A breach of any of these covenants could result in acceleration of Southern Union's debt and other financial obligations and that of its subsidiaries. Under the current credit agreements, the significant debt covenants and cross defaults are as follows:

(a) Under the Company's Long-Term Facility, the consolidated debt to total capitalization ratio, as defined therein, cannot exceed 65 percent.
(b) Under the Company's Long-Term Facility, the Company must maintain an earnings before interest, tax, depreciation and amortization interest coverage ratio of at least 2.00 times.
(c) Under the Company's First Mortgage Bond indentures for the Fall River Gas division of New England Gas Company, the Company's consolidated debt to total capitalization ratio, as defined therein, cannot exceed 70 percent at the end of any calendar quarter.
(d) All of the Company's major borrowing agreements contain cross-defaults if the Company defaults on an agreement involving at least $3 million of principal.

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In addition to the above restrictions and default provisions, the Company and/or its subsidiaries are subject to a number of additional restrictions and covenants. These restrictions and covenants include limitations on additional debt at some of its subsidiaries; limitations on the use of proceeds from borrowing at some of its subsidiaries; limitations, in some cases, on transactions with its affiliates; limitations on the incurrence of liens; potential limitations on the abilities of some of its subsidiaries to declare and pay dividends and potential limitations on some of its subsidiaries to participate in the cash management program; and limitations on the Company's ability to prepay debt.

Retirement of Debt Obligations

The Company plans to refinance its $425 million of debt maturing in August 2008 with new capital market debt or bank financings. Alternatively, should the Company not be successful in its refinancing efforts, the Company may choose to retire such debt upon maturity by utilizing some combination of cash flows from operations, draw downs under existing credit facilities, and altering the timing of controllable expenditures, among other things. The Company believes, based on its investment grade credit ratings and general financial condition, successful historical access to capital and debt markets, current economic and capital market conditions and market expectations regarding the Company's future earnings and cash flows, that it will be able to refinance and/or retire these obligations under acceptable terms prior to their maturity. There can be no assurance, however, that the Company will be able to achieve acceptable refinancing terms in any negotiation of new capital market debt or bank financings. Moreover, there can be no assurance the Company will be successful in its implementation of these refinancing and/or retirement plans and the Company's inability to do so would cause a material adverse effect on the Company's financial condition and liquidity.

14. Benefits

Pension and Other Postretirement Benefit Plans. The Company has funded non-contributory defined benefit pension plans (*pension plans*) which cover substantially all Distribution segment employees. Normal retirement age is 65, but certain plan provisions allow for earlier retirement. Pension benefits are calculated under formulas principally based on average earnings and length of service for salaried and non-union employees and average earnings and length of service or negotiated non-wage based formulas for union employees. At the beginning of 2006, the Company had eight pension plans. Effective August 24, 2006, the Company's responsibility for benefit obligations under five of these plans was relieved upon the transfer of the plans to the buyers of the assets of PG Energy and the Rhode Island operations of New England Gas Company.

The Company has postretirement health care and life insurance plans (*other postretirement plans*) which cover substantially all Distribution and Transportation and Storage segment employees and effective January 1, 2008, all Corporate employees. The health care plans generally provide for cost sharing between the Company and its retirees in the form of retiree contributions, deductibles, coinsurance and a fixed cost cap on the amount the Company pays annually to provide future retiree health care coverage under certain of these plans. At the beginning of 2006, the Company had six other postretirement plans. Effective August 24, 2006, the Company's responsibility for benefit obligations under two of these plans was relieved upon the transfer of the plans to the buyer of the Rhode Island operations of New England Gas Company.

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The following tables summarize the impact of the adoption of Statement No. 158, after recognition of the current period change in additional minimum liabilities (*AML*) under Statement No. 87, on the Company's pension plans and other postretirement plans reported in the Consolidated Balance Sheet at December 31, 2006:

	Pension Plans				
	Pre-SFAS 158 without AML adjustment	AML adjustment	Pre-SFAS 158 with AML adjustment	SFAS 158 adoption adjustment	Post-SFAS 158
	(in thousands)				
Intangible asset (included in *Deferred charges*)	$ 4,883	$ (1,085)	$ 3,798	$ (3,798)	$ -
Pension liabilities, current (included in *Other current liabilities*)	-	-	-	13	13
Pension liabilities, noncurrent (included in *Deferred credits*)	58,062	(12,016)	46,046	7,066	53,112
Accumulated deferred income taxes (benefit)	(16,234)	4,128	(12,106)	(4,107)	(16,213)
Accumulated other comprehensive income (loss), net of tax	(26,711)	6,803	(19,908)	(6,770)	(26,678)
Accumulated other comprehensive income (loss), pre-tax	(42,945)	10,931	(32,014)	(10,877)	(42,891)

	Other Postretirement Plans				
	Pre-SFAS 158 without AML adjustment	AML adjustment	Pre-SFAS 158 with AML adjustment	SFAS 158 adoption adjustment	Post-SFAS 158
	(in thousands)				
Prepaid postretirement costs (included in *Deferred charges*)	$ -	$ -	$ -	$ 248	$ 248
Postretirement liabilities, current (included in *Other current liabilities*)	-	-	-	87	87
Postretirement liabilities, noncurrent (included in *Deferred credits*)	57,258	-	57,258	(29,402)	27,856
Accumulated deferred income taxes	-	-	-	6,750	6,750
Accumulated other comprehensive income (loss), net of tax	-	-	-	22,813	22,813
Accumulated other comprehensive income (loss), pre-tax	-	-	-	29,563	29,563

The adoption of Statement No. 158 had no effect on the Consolidated Statement of Operations for the year ended December 31, 2006, or for any prior period presented and has not negatively impacted any financial covenants.

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Obligations and Funded Status.

Pension and other postretirement benefit liabilities are accrued on an actuarial basis during the years an employee provides services. The following tables contain information about the obligations and funded status of the Company's pension and other postretirement plans on a combined basis:

	Pension Benefits At December 31,		Other Postretirement Benefits At December 31,	
	2007	2006	2007	2006
	(In thousands)			
Change in benefit obligation:				
Benefit obligation at beginning of period	$ 162,955	$ 415,338	$ 74,082	$ 115,148
Service cost	2,715	7,443	1,788	2,507
Interest cost	9,388	20,889	4,053	5,556
Benefits paid, net	(9,900)	(19,668)	(2,893)	(4,418)
Medicare Part D subsidy receipts	-	-	289	-
Actuarial (gain) loss and other	(3,512)	(24,347)	(3,780)	(9,925)
Plan amendments	1,178	-	2,734	972
Curtailment recognition	-	(28,119)	-	(2,250)
Settlement recognition and other (1)	-	(208,581)	-	(33,508)
Benefit obligation at end of period	$ 162,824	$ 162,955	$ 76,273	$ 74,082
Change in plan assets:				
Fair value of plan assets at beginning of period	$ 108,633	$ 298,289	$ 46,233	$ 45,509
Return on plan assets and other	12,796	17,187	1,494	3,203
Employer contributions	16,813	28,399	9,176	14,926
Benefits paid, net	(9,900)	(19,668)	(2,893)	(4,418)
Settlement recognition and other (1)	-	(215,574)	-	(12,987)
Fair value of plan assets at end of period	$ 128,342	$ 108,633	$ 54,010	$ 46,233
Funded status:				
Funded status at measurement date	$ (34,482)	$ (54,322)	$ (22,263)	$ (27,849)
Contributions subsequent to measurement date	4,025	1,197	440	154
Funded status at end of period	$ (30,457)	$ (53,125)	$ (21,823)	$ (27,695)
Amounts recognized in the Consolidated Balance Sheet consist of:				
Noncurrent assets	$ -	$ -	$ 1,418	$ 248
Current liabilities	(13)	(13)	(57)	(87)
Noncurrent liabilities	(30,444)	(53,112)	(23,184)	(27,856)
	$ (30,457)	$ (53,125)	$ (21,823)	$ (27,695)
Amounts recognized in Accumulated other comprehensive loss (pre-tax basis) consist of:				
Net actuarial loss (gain)	$ 24,376	$ 39,093	$ (12,831)	$ (11,128)
Prior service cost (credit)	4,353	3,798	(12,892)	(18,435)
	$ 28,729	$ 42,891	$ (25,723)	$ (29,563)

(1) Effective August 24, 2006, the Company transferred five pension plans and two other postretirement plans to the buyers of the assets of the Company's PG Energy natural gas distribution division and the Rhode Island operations of its New England Gas Company

natural gas distribution division.

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The accumulated benefit obligation for all defined benefit pension plans was $155 million and $155.9 million at December 31, 2007 and 2006, respectively.

The following table summarizes information for plans with an accumulated benefit obligation in excess of plan assets:

	Pension Benefits December 31, 2007	Pension Benefits December 31, 2006	Other Postretirement Benefits December 31, 2007	Other Postretirement Benefits December 31, 2006
	(In thousands)			
Projected benefit obligation	$ 162,824	$ 162,955	N/A	N/A
Accumulated benefit obligation	154,950	155,876	$ 71,571	$ 68,033
Fair value of plan assets	128,342	108,633	47,890	39,937

Net Periodic Benefit Cost.

Net periodic benefit cost for the years ended December 31, 2007, 2006 and 2005 includes the components noted in the table below. The table below has been reclassified for all prior periods to present net periodic benefit cost included in operating expenses from continuing operations, and excludes the net periodic benefit cost of the Company's discontinued operations. Net periodic pension cost for discontinued operations totaled $50.4 million and $7.9 million for the years ended December 31, 2006 and 2005, respectively. Net periodic other postretirement benefit costs for discontinued operations totaled $(13.8) million and $2.9 million for the years ended December 31, 2006 and 2005, respectively. See *Note 19 – Discontinued Operations* for additional related information.

	Pension Benefits Years Ended December 31, 2007	2006	2005	Other Postretirement Benefits Years Ended December 31, 2007	2006	2005
	(In thousands)					
Net Periodic Benefit Cost:						
Service cost	$ 2,715	$ 2,599	$ 2,550	$ 1,788	$ 1,890	$ 2,908
Interest cost	9,388	8,899	9,355	4,053	3,615	4,908
Expected return on plan assets	(9,619)	(8,909)	(8,728)	(2,858)	(1,871)	(1,375)
Prior service cost amortization	623	584	782	(2,809)	(3,011)	(551)
Actuarial (gain) loss amortization	8,029	7,236	5,364	(768)	(145)	(163)
Curtailment recognition	-	-	3,172	-	-	-
Settlement recognition	-	-	(644)	-	-	-
Transfer of assets in excess of obligations	-	-	-	1,915	-	-
	11,136	10,409	11,851	1,321	478	5,727
Regulatory adjustment (1)	(1,578)	(7,710)	(7,521)	2,665	2,665	2,665
Net periodic benefit cost	$ 9,558	$ 2,699	$ 4,330	$ 3,986	$ 3,143	$ 8,392

(1) In the Distribution segment, the Company recovers certain qualified pension benefit plan and other postretirement benefit plan costs through rates charged to utility customers. Certain utility commissions require that the recovery of these costs be based on the Employee Retirement Income Security Act or other utility commission specific guidelines. The difference between these amounts and periodic benefit cost calculated pursuant to Statement No. 87 is initially deferred as a regulatory asset and subsequently amortized to periodic benefit cost over periods, promulgated by the applicable utility commission, in which this difference will be recovered in rates.

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The estimated net actuarial loss (gain) and prior service cost (credit) for pension plans that will be amortized from *Accumulated other comprehensive loss* into net periodic benefit cost during 2008 are $6.9 million and $552,000, respectively. The estimated net actuarial loss (gain) and prior service cost (credit) for other postretirement plans that will be amortized from *Accumulated other comprehensive loss* into net periodic benefit cost during 2008 are ($1.2) million and ($2.4) million, respectively.

Assumptions.

The weighted-average assumptions used in determining benefit obligations are shown in the table below:

	Pension Benefits Years Ended December 31,			Other Postretirement Benefits Years Ended December 31,		
	2007	**2006**	**2005**	**2007**	**2006**	**2005**
Discount rate	6.24%	5.77%	5.50%	6.34%	5.78%	5.50%
Rate of compensation increase (average)	3.47%	3.24%	3.24%	N/A	N/A	N/A

The weighted-average assumptions used in determining net periodic benefit cost are shown in the table below. The table has been reclassified for all prior periods to present discount rate data for plans relating to continuing operations, and excludes the discount rate data of the plans that relate to the Company's discontinued operations. See *Note 19 – Discontinued Operations* for additional related information.

	Pension Benefits Years Ended December 31,			Other Postretirement Benefits Years Ended December 31,		
	2007	**2006**	**2005**	**2007**	**2006**	**2005**
Discount rate	5.77%	5.50%	5.75%	5.78%	5.50%	5.75%
Expected return on assets:						
Tax exempt accounts	8.75%	8.75%	9.00%	7.00%	7.00%	7.00%
Taxable accounts	N/A	N/A	N/A	5.00%	5.00%	5.00%
Rate of compensation increase	3.24%	3.24%	3.40%	N/A	N/A	N/A

The Company employs a building block approach in determining the expected long-term rate of return on the plans' assets, with proper consideration of diversification and rebalancing. Historical markets are studied and long-term historical relationships between equities and fixed-income are preserved consistent with the widely accepted capital market principle that assets with higher volatility generate a greater return over the long run. Current market factors such as inflation and interest rates are evaluated before long-term market assumptions are determined. Peer data and historical returns are reviewed to ensure reasonableness and appropriateness.

The assumed health care cost trend rates used for measurement purposes are shown in the table below:

	December 31,	
	2007	**2006**
Health care cost trend rate assumed for next year	10.00%	11.00%
Ultimate trend rate	5.13%	4.80%
Year that the rate reaches the ultimate trend rate	2017	2013

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Assumed health care cost trend rates have a significant effect on the amounts reported for health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	One Percentage Point Increase	One Percentage Point Decrease
	(In thousands)	
Effect on total of service and interest cost	$ 733	$ (587)
Effect on accumulated postretirement benefit obligation	$ 7,082	$ (5,754)

Plan Assets.

The assets of the pension plans are invested in accordance with several investment practices that emphasize long-term investment fundamentals with an investment objective of long-term growth, taking into consideration risk tolerance and asset allocation strategies.

The broad goal and objective of the investment of the pension plans' assets is to ensure that future growth of the assets is sufficient to offset normal inflation plus liability requirements of the plans' beneficiaries. Pension plan assets should be invested in such a manner to minimize the necessity of net contributions to the plans to meet the plans' commitments. The contributions will also be affected by the applicable discount rate that is applied to future liabilities. The discount rate will affect the net present value of the future liability and, therefore, the funded status.

The assets of the postretirement health care and life insurance plans are invested in accordance with sound investment practices that emphasize long-term investment fundamentals. The Investment Committee of the Company's Board of Directors has adopted an investment objective of income and growth for the postretirement plans. This investment objective (i) is a risk-averse balanced approach that emphasizes a stable and substantial source of current income and some capital appreciation over the long-term; (ii) implies a willingness to risk some declines in value over the short-term, so long as the postretirement plans are positioned to generate current income and exhibit some capital appreciation; (iii) is expected to earn long-term returns sufficient to keep pace with the rate of inflation over most market cycles (net of spending and investment and administrative expenses), but may lag inflation in some environments; (iv) diversifies the postretirement plans in order to provide opportunities for long-term growth and to reduce the potential for large losses that could occur from holding concentrated positions; and (v) recognizes that investment results over the long-term may lag those of a typical balanced portfolio since a typical balanced portfolio tends to be more aggressively invested. Nevertheless, the postretirement plans are expected to earn a long-term return that compares favorably to appropriate market indices.

It is expected that these objectives can be obtained through a well-diversified portfolio structured in a manner consistent with the investment policy.

The Company's weighted average asset allocation by asset category for the measurement periods presented is as follows:

	Pension Benefits At September 30,		Other Postretirement Benefits At September 30,	
Asset Category	**2007**	**2006**	**2007**	**2006**
Equity securities	61%	76%	31%	24%
Debt securities	24%	10%	62%	66%
Other - cash equivalents	15%	14%	7%	10%
Total	100%	100%	100%	100%

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Based on the pension plan objectives, target asset allocations are as follows: equity of 50 percent to 80 percent, fixed income of 20 percent to 50 percent and cash and cash equivalents of 0 percent to 10 percent.

Based on the other postretirement plan objectives, target asset allocations are as follows: equity of 25 percent to 35 percent, fixed income of 65 percent to 75 percent and cash and cash equivalents of 0 percent to 10 percent.

The above referenced target asset allocations for pension and other postretirement benefits are based upon guidelines established by the Company's Investment Policy and is monitored by the Investment Committee of the board of directors in conjunction with an external investment advisor. On occasion, the asset allocations may fluctuate as compared to these guidelines as a result of Investment Committee actions.

Contributions.

The Company expects to contribute approximately $14.3 million to its pension plans and approximately $10 million to its other postretirement plans in 2008. The Company funds the cost of the plans in accordance with federal regulations, not to exceed the amounts deductible for income tax purposes.

Benefit Payments.

The Company's estimate of expected benefit payments, which reflect expected future service, as appropriate, in each of the five succeeding years and in the aggregate for the five years thereafter are shown in the table below:

Years	Pension Benefits	Other Postretirement Benefits (Gross, Before Medicare Part D)	Other Postretirement Benefits (Medicare Part D Subsidy Receipts)
		(In thousands)	
2008	$ 10,172	$ 4,093	$ 607
2009	10,774	4,083	684
2010	10,929	4,296	763
2011	10,854	4,831	855
2012	12,084	5,467	809
2013-2017	61,034	37,394	5,533

The Medicare Prescription Drug Act was signed into law December 8, 2003. This act provides for a prescription drug benefit under Medicare (*Medicare Part D*) as well as a federal subsidy, which is not taxable, to sponsors of retiree health care benefit plans that provide a prescription drug benefit that is at least actuarially equivalent to Medicare Part D.

Defined Contribution Plan. The Company sponsors a defined contribution savings plan (*Savings Plan*) that is available to all employees. The Company provides maximum matching contributions based upon certain Savings Plan provisions ranging from 2 percent to 6.25 percent to the participant's compensation paid into the Savings Plan. Company contributions are 100 percent vested after five years of continuous service for all plans other than Missouri Gas Energy union employees and employees of the Fall River operation, which are 100 percent vested after six years of continuous service. Company contributions to the Savings Plan during the years ended December 31, 2007, 2006 and 2005 were $3.8 million, $5.1 million and $4.5 million, respectively.

In addition, the Company makes employer contributions to separate accounts, referred to as Retirement Power Accounts, within the defined contribution plan. The contribution amounts are determined as a percentage of compensation and range from 2.5 percent to 11 percent. Company contributions to Retirement Power Accounts during the years ended December 31, 2007, 2006 and 2005 were $6.6 million, $5.1 million and $4.8 million, respectively.

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Common Stock Held in Trust. From time to time, Southern Union purchases outstanding shares of its common stock to fund certain Company employee stock-based compensation plans. At December 31, 2007 and 2006, 783,445 and 863,458 shares, respectively, of common stock were held by various rabbi trusts for certain of those Company's benefit plans.

Benefit Plan Termination. Effective June 30, 2005, the Company terminated its 1997 Supplemental Retirement Plan (*Supplemental Plan*), which was a non-contributory cash balance retirement plan for certain current and former executive employees of the Company. As a result, the Company had an estimated pension net loss of $1.3 million comprised of a $1.6 million loss on pension curtailment, recognized in the second quarter of 2005, and a $251,000 gain on pension settlement, recognized in the third quarter of 2005. Prior to the termination of the Supplemental Plan, the Company also recorded a $1.1 million loss on pension curtailment in the second quarter of 2005 that was triggered by pension payments made to a former executive of the Company under this plan.

Also effective June 30, 2005, the Company terminated its 2000 Executive Deferred Stock Plan, which was a defined contribution deferred compensation plan for certain management and highly compensated employees. The plan's assets were held in a rabbi trust and were distributed to participants during the fourth quarter of 2005. The termination of this plan did not have a material effect on the Company's consolidated financial statements.

15. Taxes on Income

The following table provides a summary of the current and deferred components of income tax expense from continuing operations for the periods presented:

Income Tax Expense	Years Ended December 31, 2007	2006	2005
		(In thousands)	
Current:			
Federal	$ 18,458	$ 19,798	$ 168
State	5,654	2,251	1,062
	24,112	22,049	1,230
Deferred:			
Federal	62,502	74,563	43,110
State	8,645	12,635	5,712
	71,147	87,198	48,822
Total federal and state income tax expense from continuing operations	$ 95,259	$ 109,247	$ 50,052
Effective tax rate	29.4%	33.5%	24.6%

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Deferred income taxes result from temporary differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities. The principal components of the Company's deferred tax assets (liabilities) are as follows:

Deferred Income Tax Analysis	December 31, 2007	December 31, 2006
	(In thousands)	
Deferred income tax assets:		
Alternative minimum tax credit	$ 13,560	$ 8,178
Post-retirement benefits	24,320	17,673
Pension benefits	6,579	13,810
Unconsolidated investments	5,443	11,530
Other	19,621	27,936
Total deferred income tax assets	69,523	79,127
Deferred income tax liabilities:		
Property, plant and equipment	(693,350)	(624,797)
Investment in CCE Holdings (Citrus)	(34,113)	(18,700)
Goodwill	(15,665)	(14,592)
Regulatory liability	(2,020)	(2,989)
Other	(16,077)	(35,738)
Total deferred income tax liabilities	(761,225)	(696,816)
Net deferred income tax liability	(691,702)	(617,689)
Less current income tax assets (liabilities)	1,303	(512)
Accumulated deferred income taxes	$ (693,005)	$ (617,177)

Deferred credits in the accompanying Consolidated Balance Sheet includes $87,000 and $133,000 of unamortized deferred investment tax credit as of December 31, 2007 and 2006, respectively.

The Company completed an analysis of its deferred tax accounts in 2005. As a result of the 2005 analysis and expiring statute of limitations in 2006, federal and state income tax expense for the years ending December 31, 2006 and 2005 was decreased $8.4 million and $6.4 million, respectively, primarily due to adjustments related to bad debt reserves and PP&E. The decrease in income tax expense for the years ended December 31, 2006 and 2005 is comprised of federal income taxes of $7.5 million and $4.8 million, respectively, and state income taxes of $900,000 and $1.6 million, respectively.

In November 2006, the Internal Revenue Service (*IRS*) completed its examination of the Company's federal income tax return for the fiscal year ended June 30, 2003. The Company reached a favorable settlement regarding the like-kind exchange structure under Section 1031 of the Internal Revenue Code related to the sale of the assets of its Southern Union Gas natural gas operating division and related assets to ONEOK Inc. for approximately $437 million in January 2003 and the acquisition of Panhandle in June 2003.

The Company was successful in sustaining all but $26.3 million of the original estimated $90 million of income tax deferral associated with the like-kind structure. However, the Company's net tax due to the IRS was reduced to $11.6 million, plus interest, primarily due to alternative minimum tax credits and other favorable audit results. As a result of the IRS examination, the Company paid $12.6 million of income tax to the IRS in November 2006, received a refund of $1 million from the IRS and paid $1.4 million to state and local jurisdictions in 2007. The Company also paid $2.4 million ($1.5 million net of tax) in 2007 representing interest payable to the IRS, state and local jurisdictions as a result of the IRS examination of the year ended June 30, 2003. No penalties were assessed to the Company in this IRS examination.

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The Company will be entitled to recover a corresponding $26.3 million of income tax benefit over time from additional depreciation deductions from the Panhandle assets due to higher tax basis in such assets as a result of the reduction of income tax benefits from the like-kind exchange.

The differences between the Company's effective income tax rate (*EITR*) and the U.S. federal income tax statutory rate are as follows:

	Years Ended December 31,		
Effective Income Tax Rate Analysis	**2007**	**2006**	**2005**
		(In thousands)	
Computed statutory income tax expense from continuing operations at 35%	$ 113,389	$ 114,215	$ 71,102
Changes in income taxes resulting from:			
Valuation allowance	-	-	(11,942)
Dividend received deduction	(28,994)	(10,696)	(8,732)
Executive compensation, non deductible	491	5,063	-
State income taxes, net of federal income tax benefit	9,295	9,411	4,403
Analysis of deferred tax accounts	-	(7,490)	(4,757)
Other	1,078	(1,256)	(22)
Actual income tax expense from continuing operations	$ 95,259	$ 109,247	$ 50,052

The Company adopted FIN 48 on January 1, 2007. The implementation of FIN 48 did not have a material impact on the consolidated financial statements and did not require an adjustment to *Retained earnings (deficit)*. The amount of unrecognized tax benefits at January 1, 2007 was $600,000, all of which would impact the Company's EITR if recognized. There are no changes to the Company's unrecognized tax benefits during 2007. The remaining amount of unrecognized tax benefits should be reduced to nil based on anticipated statute of limitations expirations in 2008.

The Company's policy is to classify and accrue interest expense and penalties on income tax underpayments (overpayments) as a component of income tax expense in its Consolidated Statement of Operations, which is consistent with the recognition of these items in prior reporting periods. At January 1, 2007, the Company recorded a liability of $2.4 million ($1.5 million, net of tax) representing interest payable to the IRS, state and local jurisdictions as a result of the IRS examination of the year ended June 30, 2003. All of the interest liability was paid in 2007. At December 31, 2007, the Company had no remaining federal, state and local interest liabilities. There were no federal penalties assessed as a result of this examination and no significant state penalties associated with the amended tax return filings.

The Company is no longer subject to U.S. federal, state or local examinations for the tax year ended June 30, 2002 and prior years. Although the Company settled the IRS examination of the year ended June 30, 2003 in 2006, the statute did not expire until December 31, 2007. The state impact of the federal change remains subject to state and local examination for a period of up to one year after formal notification to the state and local jurisdictions. The Company filed all required amended state tax returns in 2007 as a result of the federal change. Therefore, the state and local statutes will expire with respect to the tax year ended June 30, 2003 in 2008.

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16. Regulation and Rates

Panhandle. The Company has commenced construction of an enhancement at its Trunkline LNG terminal. This infrastructure enhancement project, which was originally expected to cost approximately $250 million, plus capitalized interest, will increase send out flexibility at the terminal and lower fuel costs. Recent cost projections indicate the construction costs will likely be approximately $365 million, plus capitalized interest. The revised costs reflect increases in the quantities and cost of materials required, higher contract labor costs and an allowance for additional contingency funds, if needed. The negotiated rate with the project's customer, BG LNG Services, will be adjusted based on final capital costs pursuant to a contract-based formula. The project is now expected to be in operation in the second quarter of 2009. In addition, Trunkline LNG and BG LNG Services agreed to extend the existing terminal and pipeline services agreements through 2028, representing a five-year extension. Approximately $178.3 million and $40.8 million of costs are included in the line item *Construction work-in-progress* at December 31, 2007 and 2006, respectively.

The Company has received approval from FERC to modernize and replace various compression facilities on PEPL. Such replacements are ultimately expected to be made at eleven compressor stations, with three stations completed as of December 31, 2007. Three additional stations are in progress and planned to be completed by the end of 2009, with the remaining cost for these stations estimated at approximately $100 million, plus capitalized interest. Planning for the other five compressor stations on which construction has not yet begun is continuing, with the timing and scope of the work on these stations being evaluated on an individual station basis. The Company is also replacing approximately 32 miles of existing pipeline on the east end of the PEPL system at a current estimated cost of approximately $125 million, plus capitalized interest, which will further improve system integrity and reliability. The revised higher cost relates to various construction issues and delays which have resulted in current estimated in-service dates for the related facilities around the end of the first quarter of 2008 or in the second quarter of 2008. Approximately $124.7 million and $57.9 million of costs related to these projects are included in the line item *Construction work-in-progress* at December 31, 2007 and 2006, respectively.

Trunkline has completed construction on its field zone expansion project. The expansion project included the north Texas expansion and creation of additional capacity on Trunkline's pipeline system in Texas and Louisiana to increase deliveries to Henry Hub. Trunkline has increased the capacity along existing rights-of-way from Kountze, Texas to Longville, Louisiana by approximately 625 MMcf/d with the construction of approximately 45 miles of 36-inch diameter pipeline. The project included horsepower additions and modifications at existing compressor stations. Trunkline has also created additional capacity to Henry Hub with the construction of a 13.5-mile, 36-inch diameter pipeline loop from Kaplan, Louisiana directly into Henry Hub. The Henry Hub lateral provides capacity of 1 Bcf/d from Kaplan, Louisiana to Henry Hub. The majority of the project was put into service in late December 2007 with the remainder placed in-service in February 2008. The Company currently estimates the final project costs will total approximately $250 million, plus capitalized interest. The estimated costs include a $40 million contribution in aid of construction to a subsidiary of Energy Transfer, which was paid in January 2008 and is expected to be amortized over the life of the facilities. Approximately $26.4 million and $12.5 million of costs for this project are included in the line item *Construction work-in-progress* at December 31, 2007 and 2006, respectively, with $178.3 million closed to *Plant in service* in December 2007.

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FERC is responsible under the Natural Gas Act for assuring that rates charged by interstate pipelines are "just and reasonable." To enforce that requirement, FERC applies a ratemaking methodology that determines an allowed rate of return on common equity for the companies it regulates. On October 25, 2006, a group including producers and various trade associations filed a complaint under Section 5 of the Natural Gas Act against Pan Gas Storage, LLC (d.b.a. *Southwest Gas Storage*) requesting that FERC initiate an investigation into Southwest Gas Storage's rates, terms and conditions of service and grant immediate interim rate relief. FERC initiated a Section 5 proceeding on December 21, 2006, setting this issue for hearing. Pursuant to FERC order, Southwest Gas Storage filed a cost and revenue study with FERC on February 20, 2007. On August 1, 2007, Southwest Gas Storage filed a Section 4 rate case requesting an increase in rates. On August 31, 2007, the FERC accepted Southwest Gas Storage's rate increase to become effective on February 1, 2008, subject to refund. This order also consolidated the Section 5 proceeding with the Section 4 rate case. On November 28, 2007, Southwest Gas Storage filed a settlement with FERC. The settlement was approved by FERC on February 12, 2008, which settlement resulted in Southwest Gas Storage's rates remaining substantially similar to its rates that were in effect prior to the Section 4 and Section 5 proceedings.

On January 26, 2007, Southwest Gas Storage filed an abandonment application to reduce the certificated storage capacity of its North Hopeton field by approximately 6 Bcf and to acquire 3 Bcf of additional base gas to maintain storage field operations. This filing brings the certificated capacity in line with operational performance of the field. On September 7, 2007, FERC approved Southwest Gas Storage's North Hopeton field modifications. Southwest Gas Storage has entered into a third-party agreement to replace this storage capacity, effective April 1, 2007, with an initial term of two years.

Sea Robin Pipeline Company, LLC (*Sea Robin*) filed a rate case with FERC in June 2007, requesting an increase in its maximum rates. Several parties have submitted protests to the rate increase filing with FERC. On July 30, 2007, FERC suspended the effectiveness of the filed rate increase until January 1, 2008. The filed rates were put into effect January 1, 2008, subject to refund. The final outcome of the rate case has many variables and potential outcomes and it is impossible to predict its timing or materiality at this time.

On December 15, 2003, the U.S. Department of Transportation issued a final rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the rule defines as HCAs. This rule resulted from the enactment of the Pipeline Safety Improvement Act of 2002. The rule requires operators to have identified HCAs along their pipelines by December 2004, and to have begun baseline integrity assessments, comprised of in-line inspection (smart pigging), hydrostatic testing or direct assessment, by June 2004. Operators must rank the risk of their pipeline segments containing HCAs and must complete assessments on at least 50 percent of the segments using one or more of these methods by December 2007. Assessments will generally be conducted on the higher risk segments first, with the balance being completed by December 2012. In addition, some system modifications will be necessary to accommodate the in-line inspections. As of December 31, 2007, the Company had completed 80 percent of the risk assessments. All systems operated by the Company will be compliant with the rule; however, while identification and location of all HCAs has been completed, it not practicable to determine with certainty the total scope of required remediation activities prior to completion of the assessments and inspections. The required modifications and inspections are currently estimated to be in the range of approximately $20 million to $28 million per year through 2012.

Missouri Gas Energy. On September 21, 2004, the Missouri Public Service Commission (*MPSC*) issued a rate order authorizing Missouri Gas Energy to increase base revenues by $22.4 million, effective October 2, 2004. Missouri Gas Energy filed various appeals related to this matter seeking increased base revenues in addition to those contained in the MPSC's order on grounds that the capital structure and 10.5 percent return on equity used by the MPSC in determining such increase did not provide an adequate rate of return. On April 11, 2006, the Missouri Supreme Court denied a hearing on this matter, effectively concluding the Company's appeal.

On May 1, 2006, Missouri Gas Energy announced the filing of a proposal with the MPSC to increase annual revenues by approximately $41.7 million, or 6.8 percent. A hearing on this matter with the MPSC was held in January 2007. The MPSC issued a Report and Order on March 22, 2007, authorizing an annual revenue increase of $27.2 million, or 4.5 percent. In its order, the MPSC calculated the revenue increase using a return

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on equity of 10.5 percent and set residential rates using a straight fixed-variable rate design, thereby eliminating the impact of weather and conservation on residential margin revenues and related earnings. The new rates went into effect on April 3, 2007. This rate order has been appealed by Missouri Gas Energy and the Office of the Public Counsel, with Missouri Gas Energy challenging the authorized return as too low and the Office of the Public Counsel challenging the residential rate design. A final ruling in the appeal is not expected until 2009.

Through filings made on various dates, the staff of the MPSC recommended the MPSC disallow a total of approximately $47.7 million in gas costs incurred during the period July 1, 1997 through June 30, 2005. By order issued August 2, 2007, the MPSC adopted the MPSC staff's formal withdrawal of disallowance recommendations totaling approximately $35.3 million in response to a January 2007 Missouri Supreme Court ruling. By orders issued on August 2, 2007 and October 2, 2007, the MPSC also rejected the MPSC staff's recommendations regarding $8 million of the remaining gas cost disallowance. In a filing made with the MPSC on November 2, 2007, the MPSC staff withdrew from consideration the remaining $4.4 million in disallowance recommendations. By orders issued on November 8, 2007, the MPSC accepted the withdrawal of these remaining disallowance recommendations and closed these cases. There was no impact to the Company's consolidated financial statements related to the withdrawal of these gas cost disallowance recommendations.

New England Gas Company. On June 8, 2007, New England Gas Company filed with the Massachusetts Department of Public Utilities (*MDPU*) a proposed rate settlement with respect to its Massachusetts operations. The settlement agreement provides, among other things, for an overall revenue increase of $4.6 million phased in over an eight-month period, including the implementation of adjustment mechanisms for the recovery of pension costs, other postretirement benefit costs and gas cost-related uncollectible expense effective August 1, 2007, and a base rate increase of $2 million on April 1, 2008. The MDPU issued an order on July 31, 2007 approving the rate settlement agreement effective August 1, 2007.

17. Leases

The Company leases certain facilities, equipment and office space under cancelable and non-cancelable operating leases. The minimum annual rentals under operating leases for the next five years ending December 31 are as follows: 2008— $16.4 million; 2009—$19.2 million; 2010—$18.3 million; 2011— $18.2 million; 2012—$13.9 million and thereafter $57.8 million. Rental expense was $19.9 million, $18.7 million and $20.1 million for the years ended December 31, 2007, 2006 and 2005, respectively.

18. Commitments and Contingencies

Environmental

The Company's operations are subject to federal, state and local laws and regulations regarding water quality, hazardous and solid waste management, air quality control and other environmental matters. These laws and regulations require the Company to conduct its operations in a specified manner and to obtain and comply with a wide variety of environmental registrations, licenses, permits, inspections and other approvals. Failure to comply with environmental requirements may expose the Company to significant fines, penalties and/or interruptions in operations. The Company's environmental policies and procedures are designed to achieve compliance with such laws and regulations. These evolving laws and regulations and claims for damages to property, employees, other persons and the environment resulting from current or past operations may result in significant expenditures and liabilities in the future. The Company engages in a process of updating and revising its procedures for the ongoing evaluation of its operations to identify potential environmental exposures and enhance compliance with regulatory requirements. The Company follows the provisions of American Institute of Certified Public Accountants Statement of Position 96-1, *Environmental Remediation Liabilities*, for recognition, measurement, display and disclosure of environmental remediation liabilities.

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The Company is allowed to recover environmental remediation expenditures through rates in certain jurisdictions within its Distribution segment. Although significant charges to earnings could be required prior to rate recovery for jurisdictions that do not have rate recovery mechanisms, management does not believe that environmental expenditures will have a material adverse effect on the Company's financial position, results of operations or cash flows. The table below reflects the amount of accrued liabilities recorded in the Consolidated Balance Sheet at December 31, 2007 and 2006 to cover probable environmental response actions:

	December 31, 2007	December 31, 2006
	(In thousands)	
Current	$ 6,772	$ 5,098
Noncurrent	15,209	18,632
Total Environmental Liabilities	$ 21,981	$ 23,730

During the year ended December 31, 2007, the Company had $9.3 million of expenditures related to environmental cleanup programs.

Transportation and Storage Segment Environmental Matters.

Gas Transmission Systems. Panhandle is responsible for environmental remediation at certain sites on its gas transmission systems for contamination resulting from the past use of lubricants containing polychlorinated biphenyls (*PCBs*) in compressed air systems; the past use of paints containing PCBs; and the prior use of wastewater collection facilities and other on-site disposal areas. Panhandle has developed and is implementing a program to remediate such contamination. Remediation and decontamination has been completed at each of the 35 compressor station sites where auxiliary buildings that house the air compressor equipment were impacted by the past use of lubricants containing PCBs. At some locations, PCBs have been identified in paint that was applied many years ago. A program has been implemented to remove and dispose of PCB impacted paint during painting activities. At one location on the Trunkline system, PCBs were discovered on the painted surfaces of equipment in a building that is outside of the scope of the compressed air system program and the existing PCB impacted paint program. The estimated cost to remediate the painted surfaces at this location is approximately $300,000. An initial assessment program was undertaken at seven locations to determine whether this condition exists at any of the other 78 similar buildings on the PEPL, Trunkline and Southwest Gas systems. At the seven locations assessed, which comprised a total of 15 buildings, preliminary analysis identified PCBs at regulated levels in a small number of samples at two locations. An expanded assessment program has been developed and is currently underway. As of December 31, 2007, 19 of 37 total locations have been assessed indicating PCBs at regulated levels in a small number of samples at a total of five locations. Until the results of the expanded assessment program are available, the costs associated with remediation of the painted surfaces cannot be reasonably estimated.

Other remediation typically involves the management of contaminated soils and may involve remediation of groundwater. Activities vary with site conditions and locations, the extent and nature of the contamination, remedial requirements, complexity and sharing of responsibility. The ultimate liability and total costs associated with these sites will depend upon many factors. If remediation activities involve statutory joint and several liability provisions, strict liability, or cost recovery or contribution actions, Panhandle could potentially be held responsible for contamination caused by other parties. In some instances, such as the Pierce Waste Oil sites described below, Panhandle may share liability associated with contamination with other potentially responsible parties (*PRPs*). Panhandle may also benefit from contractual indemnities that cover some or all of the cleanup costs. These sites are generally managed in the normal course of business or operations. The Company believes the outcome of these matters will not have a material adverse effect on its consolidated financial position, results of operations or cash flows.

PEPL and Trunkline, together with other non-affiliated parties, have been identified as potentially liable for conditions at three former waste oil disposal sites in Illinois – the Pierce Oil Springfield site, the Dunavan Waste

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Oil site and the McCook site (collectively, the *Pierce Waste Oil sites*). PEPL and Trunkline received notices of potential liability from the U.S. EPA for the Dunavan site by letters dated September 30, 2005. The notices demanded reimbursement to the U.S. EPA for costs incurred as of that date in the amount of approximately $1.8 million and encouraged each PRP to voluntarily negotiate an administrative settlement agreement with the U.S. EPA within certain limited time frames providing for the PRPs to conduct or finance the response activities required at the site. The demand was declined in a joint letter dated December 15, 2005 by the major PRPs, including PEPL and Trunkline. Although no formal notice has been received for the Pierce Oil Springfield site, special notice letters are anticipated and the process of listing the site on the National Priority List has begun. No formal notice has been received for the McCook site. The Company believes the outcome of these matters will not have a material adverse effect on its consolidated financial position, results of operations or cash flows.

On June 16, 2005, PEPL experienced a release of liquid hydrocarbons near Pleasant Hill, Illinois. The release occurred in the form of a mist at a valve that was in use to reduce the pressure in the pipeline as part of maintenance activities. The hydrocarbon mist affected several acres of adjacent agricultural land and a nearby marina. Approximately 27 gallons of hydrocarbons reached the Mississippi River. PEPL contacted appropriate federal and state regulatory agencies and the U.S. EPA took the lead role in overseeing the subsequent cleanup activities, which have been completed. PEPL has resolved claims of affected boat owners and the marina operator. PEPL received a violation notice from the Illinois Environmental Protection Agency (*IEPA*) alleging that PEPL was in apparent violation of several sections of the Illinois Environmental Protection Act by allowing the release. The violation notice did not propose a penalty. Responses to the violation notice were submitted and the responses were discussed with the agency. On December 14, 2005, the IEPA notified PEPL that the matter might be considered for referral to the Office of the Attorney General, the State's Attorney or the U.S. EPA for formal enforcement action and the imposition of penalties. By letter dated November 22, 2006, PEPL received a follow-up information request from the IEPA on the status of certain measures PEPL had agreed to undertake in connection with the original responses to the violation notice. On January 5, 2007, PEPL submitted a response. There has been no further contact from the IEPA on this matter. The Company believes the outcome of this matter will not have a material adverse effect on its consolidated financial position, results of operations or cash flows.

Air Quality Control. The U.S. EPA issued a final rule on regional ozone control (*NOx SIP Call*) in April 2004 that affected 20 large internal combustion engines on Panhandle's system in Illinois and Indiana. Panhandle has substantially completed the required capital improvements of approximately $23 million as of December 31, 2007. Indiana has promulgated state regulations to address the requirements of the NOx SIP Call rule that essentially follow the U.S. EPA guidance.

In early April 2007, the IEPA proposed a rule to the Illinois Pollution Control Board (*IPCB*) for adoption to control NOx emissions from reciprocating engines and turbines, including a provision applying the rule beyond issues addressed by federal provisions, pursuant to a blanket statewide application. As originally proposed, the Illinois rule required controls on engines regulated under the U.S. EPA NOx SIP Call by May 1, 2007 and the remaining engines by January 1, 2011. A pipeline consortium including PEPL and Trunkline filed an objection to the rule requesting the IPCB to bifurcate and address separately the statewide applicability provision, which was the primary driver of costs to PEPL and Trunkline. On May 17, 2007, the IPCB ruled in favor of the pipeline consortium by bifurcating the statewide applicability provision from the rest of the proposed rule. On September 20, 2007 the IPCB approved the rule that applies to the engines regulated under the NOx SIP Call rule, which the pipeline consortium was not contesting. Due to delayed approval of the rule, the compliance deadline was changed from May 1, 2007 to January 1, 2008. On August 23, 2007, the IEPA filed a motion to cancel hearings and pre-filing deadlines for the bifurcated statewide portion of the proposed Illinois engine rule, which was later granted. On December 20, 2007, the IEPA filed an amended proposal withdrawing the statewide applicability provisions of the current proposed rule and apply the rule requirements to non-attainment areas. The amended proposal was approved on January 10, 2008. No controls on PEPL and Trunkline stations are required under the most recent proposal. However, the IEPA indicated in earlier industry discussions that it was reserving the right to make future proposals for statewide controls. In the event the IEPA proposes a statewide rule again, preliminary estimates indicate the cost of compliance would require minimum capital expenditures of approximately $45 million for emission controls.

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In 2002, the Texas Commission on Environmental Quality (*TCEQ*) enacted the Houston/Galveston SIP regulations requiring reductions in NOx emissions in an eight-county area surrounding Houston. Trunkline's Cypress compressor station is affected and required the installation of emission controls. Regulations also require certain grandfathered facilities in East Texas to enter into the new source permit program, which may require the installation of emission controls at one additional facility owned by Panhandle. Management estimates capital improvements of $17.1 million will be needed at the two affected East Texas locations. The approximately $17 million of the required capital expenditures for the two affected East Texas locations have been substantially completed as of December 31, 2007. Permit limits were placed on grandfathered engines at two facilities in West Texas that are owned by PEPL. An estimated $1.9 million in capital expenditures will be required to comply with permit limitations for the West Texas facilities.

The U.S. EPA promulgated various Maximum Achievable Control Technology (*MACT*) rules in February 2004. The rules require that PEPL and Trunkline control Hazardous Air Pollutants (*HAPs*) emitted from certain internal combustion engines at major HAPs sources. Most PEPL and Trunkline compressor stations are major HAPs sources. The HAPs pollutant of concern for PEPL and Trunkline is formaldehyde. The rule, with which PEPL and Trunkline are in compliance and which had a final implementation date of June 2007, seeks to reduce formaldehyde emissions by 76 percent from these engines by requiring use of catalytic controls. PEPL has one engine fully regulated under this rule. For the other PEPL and Trunkline engines potentially subject to the engine MACT rule, emission controls and operating restrictions have been used to lower emissions below MACT thresholds. Compliance with these regulations necessitated an estimated expenditure of $1.4 million for capital improvements.

Spill Prevention, Control and Countermeasure Rules. In May 2007, the U.S. EPA extended the SPCC rule compliance dates until July 1, 2009 permitting owners and operators of facilities to prepare or amend and implement SPCC Plans in accordance with previously enacted modifications to the regulations. In October 2007, the U.S. EPA proposed amendments to the SPCC rules with the stated intention of providing greater clarity, tailoring requirements, and streamlining requirements. The Company is currently reviewing the impact of the modified regulations on its operations and may incur costs for tank integrity testing, alarms and other associated corrective actions as well as potential upgrades to containment structures. Costs associated with such activities cannot be estimated with certainty at this time, but the Company believes such costs will not have a material adverse effect on its consolidated financial position, results of operations or cash flows.

Gathering and Processing Segment Environmental Matters.

Gathering and Processing Systems. SUGS is responsible for environmental remediation at certain sites on its gathering and processing systems, resulting primarily from releases of hydrocarbons. SUGS has a program to remediate such contamination. The remediation typically involves the management of contaminated soils and may involve remediation of groundwater. Activities vary with site conditions and locations, the extent and nature of the contamination, remedial requirements and complexity. The ultimate liability and total costs associated with these sites will depend upon many factors. These sites are generally managed in the normal course of business or operations. The Company believes the outcome of these matters will not have a material adverse effect on its consolidated financial position, results of operations or cash flows.

Air Quality Control. On June 16, 2006, SUGS, as the facility operator and holder of a 50 percent interest in the Grey Ranch facility, submitted information to the TCEQ in connection with a request to permit its Grey Ranch, Texas facility to continue its current level of emissions. The State of Texas requires all previously grandfathered emission sources to obtain permits or shut down by March 1, 2008. By letter dated September 5, 2007, the TCEQ issued a permit extending current emission levels to March 1, 2009. At the conclusion of the extension period, SUGS must implement an emission control strategy that achieves specific maximum allowable emissions rates. At this time, it is anticipated that the Company will not bear any of the costs associated with an emissions control strategy.

Spill Prevention, Control and Countermeasure Rules. In May 2007, the U.S. EPA extended the SPCC rule compliance dates until July 1, 2009 permitting owners and operators of facilities to prepare or amend and implement SPCC Plans in accordance with previously enacted modifications to the regulations. In October 2007, the U.S. EPA proposed amendments to the SPCC rules with the stated intention of providing greater

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clarity, tailoring requirements, and streamlining requirements. The Company is currently reviewing the impact of the modified regulations on its operations and may incur costs for tank integrity testing, alarms and other associated corrective actions as well as potential upgrades to containment structures. Costs associated with such activities cannot be estimated with certainty at this time, but the Company believes such costs will not have a material adverse effect on its consolidated financial position, results of operations or cash flows.

Distribution Segment Environmental Matters.

The Company is responsible for environmental remediation at various contaminated sites that are primarily associated with former manufactured gas plants (*MGPs*) and sites associated with the operation and disposal activities of former MGPs that produced a fuel known as "town gas". Some byproducts of the historic manufactured gas process may be regulated substances under various federal and state environmental laws. To the extent these byproducts are present in soil or groundwater at concentrations in excess of applicable standards, investigation and remediation may be required. The sites include properties that are part of the Company's ongoing operations, sites formerly owned or used by the Company and sites owned by third parties. Remediation typically involves the management of contaminated soils and may involve removal of old MGP structures and remediation of groundwater. Activities vary with site conditions and locations, the extent and nature of the contamination, remedial requirements, complexity and sharing of responsibility; some contamination may be unrelated to former MGPs. The ultimate liability and total costs associated with these sites will depend upon many factors. If remediation activities involve statutory joint and several liability provisions, strict liability, or cost recovery or contribution actions, the Company could potentially be held responsible for contamination caused by other parties. In some instances, the Company may share liability associated with contamination with other PRPs, and may also benefit from insurance policies or contractual indemnities that cover some or all of the cleanup costs. These sites are generally managed in the normal course of business or operations. The Company believes the outcome of these matters will not have a material adverse effect on its consolidated financial position, results of operations or cash flows.

North Attleborough MGP Site in Massachusetts. In November 2003, the Massachusetts Department of Environmental Protection (*MADEP*) issued a Notice of Responsibility to New England Gas Company, acknowledging receipt of prior notifications and investigative reports submitted by New England Gas Company, following the discovery of suspected coal tar material at the site. Subsequent sampling in the adjacent river channel revealed sediment impacts necessitating the investigation of off-site properties. The Company, working with the MADEP, is in the process of performing assessment work at these properties. In a September 2006 report filed with MADEP, the Company proposed a remedy for the upland portion of the site by means of an engineered barrier, construction of which is anticipated in 2008. Assessment activities continue both on- and off-site to define the nature and extent of the impacts. It is estimated that the Company will spend approximately $8.3 million over the next several years to complete the investigation and remediation activities at this site, as well as maintain the engineered barrier. As New England Gas Company is allowed to recover environmental remediation expenditures through rates associated with its Massachusetts operations, the estimated costs associated with this site have been included in *Regulatory assets* in the Consolidated Balance Sheet.

Litigation

The Company is involved in legal, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies regarding matters arising in the ordinary course of business, some of which involve substantial amounts. Where appropriate, the Company has made accruals in accordance with FASB Statement No. 5, *Accounting for Contingencies*, in order to provide for such matters. The Company believes the final disposition of these proceedings will not have a material adverse effect on its consolidated financial position, results of operations or cash flows.

Bay Street, Tiverton, Rhode Island Site. On March 17, 2003, the Rhode Island Department of Environmental Management (*RIDEM*) sent the Company's New England Gas Company division a letter of responsibility pertaining to soils allegedly impacted by historic MGP residuals in a residential neighborhood in Tiverton, Rhode Island. Without admitting responsibility or accepting liability, New England Gas Company began assessment work in June 2003 and has continued to perform assessment field work since that time. On September 19,

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2006, RIDEM filed an Amended Notice of Violation seeking an administrative penalty of $1,000/day, which as of the date of RIDEM's filing totaled $258,000 and continues to accrue. In June 2007, the Rhode Island Legislature considered, but failed to adopt, legislation that would have increased the maximum administrative penalty under a Notice of Violation to $50,000/day on a prospective basis. In that RIDEM administrative proceeding, RIDEM has moved to extend to April 2008 the date for the completion of discovery, which motion has not yet been ruled upon by the Hearing Officer. On April 19, 2007, the Company filed a complaint, and an accompanying preliminary injunction motion, against RIDEM in Rhode Island Superior Court, seeking, among other things, a declaratory judgment that RIDEM's Amended Notice of Violation is premised on an unlawful application of RIDEM's regulations and that RIDEM's pending administrative proceeding against the Company is invalid. On July 13, 2007, the Superior Court dismissed the Company's suit, finding that RIDEM's Administrative Adjudication Division (*AAD*) has original jurisdiction to determine "responsible party" status and finding premature the Company's challenge to RIDEM's unlawful application of its own regulations because the Company did not first seek a ruling on that issue from RIDEM's AAD. The Company has appealed from part of the Superior Court's ruling, and has also filed a motion for summary judgment in the AAD proceeding seeking dismissal of same based on RIDEM's unlawful application of its own regulations. Briefing on the summary judgment motion is now complete. The Hearing Officer in the AAD proceeding has not yet issued a ruling on that motion. The Company will continue to vigorously defend itself in the AAD proceedings.

During 2005, four lawsuits were filed against New England Gas Company in Rhode Island regarding the Tiverton neighborhood. The plaintiffs seek to recover damages for the diminution in value of their property, lost use and enjoyment of their property and emotional distress in an unspecified amount. The Company removed the lawsuits to federal court and filed motions to dismiss. On November 3, 2006, the Court dismissed plaintiffs' claims relating to gross negligence, private nuisance, infliction of emotional distress and violation of the Rhode Island Hazardous Waste Management Act. The Court denied the Company's motion to dismiss as to claims relating to negligence, strict liability and public nuisance, as well as plaintiffs' request for punitive damages. In September and October 2007, the court granted the Company's motion to serve third-party complaints on a total of nine PRPs. Among the PRPs the Company impleaded is the Town of Tiverton, which asserted a counterclaim against the Company under CERCLA. On January 30, 2008, the Court denied the Company's motion for partial judgment on the pleadings seeking dismissal of plaintiffs' claims for remediation, finding, contrary to the Company's contention, that RIDEM does not have exclusive jurisdiction to determine the responsibility for and extent of remediation of plaintiffs' properties. On February 13, 2008, the Court entered a "Trial Order" superseding several prior orders, and directing that (1) on or about April 24, 2008, the Court will conduct a "Phase I" trial on claims asserted by plaintiffs and by Tiverton against the Company; (2) the Phase I trial will be bifurcated into a liability stage, and, if necessary, a damages stage, with both stages to be tried before the same jury; (3) the discovery cutoff date for the Phase I trial is extended from February 29 to March 21, 2008; (4) if necessary, a "Phase II" trial shall address the Company's third-party claims against the PRPs it has impleaded; and (5) the parties to the Phase II trial shall have 120 days after the Phase I trial to conduct discovery related thereto. The Company subsequently filed a motion seeking extension of the discovery and trial date. The Company will continue to vigorously defend itself against all four lawsuits, which have now been consolidated for trial. Based upon its current understanding of the facts, the Company does not believe the outcome of these matters will have a material adverse effect on its consolidated financial position, results of operations or cash flows.

Mercury Release. In October 2004, New England Gas Company discovered that one of its facilities had been broken into and that mercury had been released both inside a building and in the immediate vicinity, including a parking lot in a neighborhood several blocks away. Mercury from the parking lot was apparently tracked into nearby apartment units, as well as other buildings. Cleanup was completed at the property and nearby apartment units. The vandals who broke into the facility were arrested and convicted. On October 16, 2007, the U.S. Attorney in Rhode Island filed a three-count indictment against the Company in the U.S. District Court for the District of Rhode Island alleging violation of permitting requirements under the federal Resource Conservation and Recovery Act and notification requirements under the federal Emergency Planning and Community Right to Know Act relating to the 2004 incident. The Company entered a not guilty plea on October 29, 2007 and will vigorously defend itself in such action. On January 17, 2008, the Court granted the Company's motion to extend the deadline for completion of discovery to March 13, 2008, and to extend the deadline for the filing of certain motions to April 8, 2008. The Court has not yet set a trial date. The Company

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believes the outcome of this matter will not have a material adverse effect on its consolidated financial position, results of operations or cash flows.

On January 20, 2006, a complaint was filed against the Company in the Superior Court in Providence, Rhode Island regarding the mercury release from the Pawtucket facility, asserting claims for personal injury and property damage as a result of the release. The suit was removed to Rhode Island federal court on January 27, 2006. A motion to remand the case to state court filed by plaintiffs was denied on April 16, 2007. The Company thereafter moved to dismiss plaintiffs' amended complaint, which motion was granted in part, dismissing claims for public nuisance, private nuisance and violation of Rhode Island's Hazardous Waste Management Act, leaving plaintiffs with claims for negligence and strict liability. The Court has set December 1, 2008 as the Closure Date for all discovery. On October 18, 2007, an attorney representing other Pawtucket residents filed suit against the Company in the Superior Court in Providence asserting claims similar to those pending in the above-described federal court suit for personal injury and property damage. An additional complaint alleging personal injury arising out of the mercury release was filed on behalf of three plaintiffs with the District Court for the Sixth District, Providence County, Rhode Island, on January 22, 2008. The Company will vigorously defend all such suits. The Company believes the outcome of this matter will not have a material adverse effect on its consolidated financial position, results of operations or cash flows.

Hope Land. Hope Land Mineral Corporation (*Hope Land*) claimed trespass and unjust enrichment in respect of the storage rights to property that contains a portion of the Company's Howell storage field. The Company filed an action for condemnation to obtain the storage rights from Hope Land. Trial before the Michigan Circuit Court commenced in April 2007, and on May 2, 2007, the jury awarded Hope Land total compensation of approximately $91,000 in respect of condemnation and trespass and no recovery in respect of unjust enrichment. Following the verdict, the matter was settled and an Order of Dismissal was entered in the Court on July 3, 2007. The settlement of this matter had no material impact on the Company's consolidated financial position, results of operations or cash flows.

Jack Grynberg. Jack Grynberg, an individual, filed actions for damages against a number of companies, including Panhandle, now transferred to the U.S. District Court for the District of Wyoming, alleging mis-measurement of gas volumes and Btu content, resulting in lower royalties to mineral interest owners. Among the defendants are Panhandle, Citrus, Florida Gas and certain of their affiliates (*Company Defendants*). On October 20, 2006, the District Judge adopted in part the earlier recommendation of the Special Master in the case and ordered the dismissal of the case against the Company Defendants. Grynberg is appealing that action to the Tenth Circuit Court of Appeals. Grynberg's opening brief was filed on July 31, 2007. Respondents filed their brief rebutting Grynberg's arguments on November 21, 2007. A similar action, known as the Will Price litigation, also has been filed against a number of companies, including Panhandle, in U.S. District Court for the District of Kansas. Panhandle is currently awaiting the decision of the trial judge on the defendants' motion to dismiss the Will Price action. Panhandle and the other Company Defendants believe that their measurement practices conformed to the terms of their FERC gas tariffs, which were filed with and approved by FERC. As a result, the Company believes that it has meritorious defenses to these lawsuits (including FERC-related affirmative defenses, such as the filed rate/tariff doctrine, the primary/exclusive jurisdiction of FERC, and the defense that Panhandle and the other Company Defendants complied with the terms of their tariffs) and will continue to vigorously defend against them, including any appeal from the dismissal of the Grynberg case. The Company does not believe the outcome of these cases will have a material adverse effect on its consolidated financial position, results of operations or cash flows.

Southwest Gas Litigation. During 1999, several actions were commenced in federal courts by persons involved in competing efforts to acquire Southwest Gas Corporation. All of these actions eventually were transferred to the U.S. District Court for the District of Arizona (*District Court*). The trial of the Company's claims against the sole remaining defendant, former Arizona Corporation Commissioner James Irvin, was concluded on December 18, 2002, with a jury award to the Company of nearly $400,000 in actual damages and $60 million in punitive damages against former Commissioner Irvin. Following appeal to the Ninth Circuit Court of Appeals and remand to the District Court, the District Court reconsidered the punitive damages award and entered an order of remittitur on November 21, 2006, reducing the punitive damages amount to $4 million, plus interest. Irvin has appealed to the Ninth Circuit Court of Appeals. The Company anticipates that the Court's opinion will be issued in 2008. The Company intends to continue to vigorously pursue its case against former

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Commissioner Irvin, including seeking to collect all damages ultimately determined to lie against him. There can be no assurance, however, as to the amount of such damages, or as to the amount, if any, that the Company ultimately will collect.

GP II Energy Litigation. On October 23, 2006, landowners filed suit against the Company in the 109th District Court of Winkler County, Texas. Plaintiffs are seeking money damages, equitable relief and punitive damages alleging continuing pollution to underground aquifers underlying the plaintiffs' approximately 16,000 acre property. SUGS operated the Halley Plant, a hydrocarbon processing facility, which is located on a limited portion of the plaintiff landowners' ranch pursuant to a lease. On February 15, 2008, the Company learned that plaintiffs significantly revised their claims to include approximately $40 million in economic damages and approximately $85 million in punitive damages. The trial date has been postponed to June 10, 2008. The Company will continue to vigorously defend the suit. The Company does not believe the outcome of this case will have a material adverse effect on its consolidated financial position, results of operations or cash flows.

Other Commitments and Contingencies.

Hurricane Damage. Late in the third quarter of 2005, Hurricanes Katrina and Rita came ashore along the Upper Gulf Coast. These hurricanes caused damage to property and equipment owned by Sea Robin, Trunkline, and Trunkline LNG. As of December 31, 2007, the Company has incurred $35 million of capital expenditures related to the hurricanes, primarily for replacement or abandonment of damaged property and equipment at Sea Robin and construction project delays at the Trunkline LNG terminal.

The Company anticipates reimbursement from its property insurance carriers for a significant portion of damages from the hurricanes in excess of its $5 million deductible. Such reimbursement is currently estimated by the Company's property insurance carrier ultimately to be limited to 70 percent of the portion of the claimed damages accepted by the insurance carrier, but the amount is subject to the level of total ultimate claims from all companies relative to the carrier's $1 billion total limit on payout per event. As of December 31, 2007, the Company has received payments of $7.6 million from its insurance carriers. No receivables due from the insurance carriers have been recorded as of December 31, 2007.

In addition, after the 2005 hurricanes, the U.S. MMS mandated inspections by leaseholders and pipeline operators along the hurricane tracks. The Company has detected exposed pipe and other facilities on Trunkline and Sea Robin that must be re-covered to comply with applicable regulations. Capital expenditures of approximately $3.7 million have been incurred as of December 31, 2007 to address these issues. The Company will seek recovery of these expense and capital amounts as part of the hurricane-related claims.

Panhandle Capital Expenditures. The Company estimates remaining expenditures associated with its Trunkline field zone expansion and LNG terminal enhancement projects will be approximately $245 million, with approximately $200 million to be incurred in 2008, plus capitalized interest. These estimates were developed for budgeting purposes and are subject to revision.

Purchase Commitments. At December 31, 2007, the Company had purchase commitments for natural gas transportation services, storage services and certain quantities of natural gas at a combination of fixed, variable and market-based prices that have an aggregate value of approximately $1.1 billion. The Company's purchase commitments may be extended over several years depending upon when the required quantity is purchased. The Company has purchase gas tariffs in effect for all its utility service areas that provide for recovery of its purchase gas costs under defined methodologies and the Company believes that all costs incurred under such commitments will be recovered through its purchase gas tariffs.

TIF Debt Guarantee. The Company has a guaranty with a bank whereby the Company unconditionally guaranteed payment of financing obtained for the development of PEI Power Park. In March 1999, the Borough of Archbald, the County of Lackawanna, and the Valley View School District (collectively the *Taxing Authorities*) approved a Tax Incremental Financing Plan (*TIF Plan*) for the development of PEI Power Park. The TIF Plan requires that: (i) the Redevelopment Authority of Lackawanna County raise $10.6 million of funds to be used for infrastructure improvements of the PEI Power Park; (ii) the Taxing Authorities create a tax increment district and use incremental tax revenues generated from new development to service the $10.6 million debt; and (iii) PEI

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Power Corporation, a subsidiary of the Company, guarantee the debt service payments. In May 1999, the Redevelopment Authority of Lackawanna County borrowed $10.6 million from a bank under a promissory note (*TIF Debt*), which was refinanced and modified in May 2004. Beginning May 15, 2004 the TIF Debt bears interest at a variable rate equal to three-quarters percent (0.75 percent) lower than the National Prime Rate of Interest with no interest rate floor or ceiling. The TIF Debt matures on June 30, 2011. Interest-only payments were required until June 30, 2003, and semi-annual interest and principal payments are required thereafter. As of December 31, 2007, the balance outstanding on the TIF Debt was $4.6 million with an interest rate of 6.5 percent. Estimated incremental tax revenues are expected to cover approximately 51 percent of the 2008 annual debt service. Based on information available at this time, the Company believes that the $2.1 million amount provided for the potential shortfall in estimated future incremental tax revenues is adequate as of December 31, 2007.

Missouri Safety Program. Pursuant to a 1989 MPSC order, Missouri Gas Energy is engaged in a major gas safety program in its service territories (*Missouri Safety Program*). This program includes replacement of Company and customer-owned gas service and yard lines, the movement and resetting of meters, the replacement of cast iron mains and the replacement and cathodic protection of bare steel mains. In recognition of the significant capital expenditures associated with this safety program, the MPSC initially permitted the deferral and subsequent recovery through rates of depreciation expense, property taxes and associated carrying costs over a 10-year period. On August 28, 2003, the state of Missouri passed certain statutes that provided Missouri Gas Energy the ability to adjust rates periodically to recover depreciation expense, property taxes and carrying costs associated with the Missouri Safety Program, as well as investments in public improvement projects. The continuation of the Missouri Safety Program will result in significant levels of future capital expenditures. The Company incurred capital expenditures of $11.4 million in 2007 related to this program and estimates incurring approximately $141.3 million over the next 12 years, after which all service lines, representing about 40 percent of the annual safety program investment, will have been replaced.

Other. Effective May 28, 2006, PEPL agreed to a three-year contract with a bargaining unit representing its employees.

Of the Company's employees represented by unions, Missouri Gas Energy employs 61 percent, New England Gas Company employs 10 percent and Panhandle employs 29 percent. No employees of SUGS are currently represented by bargaining units.

The Company had standby letters of credit outstanding of $18.5 million and $8.7 million at December 31, 2007 and 2006, respectively, which guarantee payment of insurance claims and other various commitments.

19. Discontinued Operations

On August 24, 2006, the Company completed the sale of the assets of its PG Energy natural gas distribution division to UGI Corporation for $580 million in cash, excluding certain working capital adjustment reductions of approximately $24.4 million, which were paid in the first quarter of 2007. Additionally, on August 24, 2006, the Company completed the sale of the Rhode Island operations of its New England Gas Company natural gas distribution division to National Grid USA for $575 million in cash, less the assumption of approximately $77 million of debt and excluding certain working capital adjustment reductions of approximately $24.9 million, which were paid in the first quarter of 2007.

The results of operations of these divisions have been segregated and reported as *Discontinued operations* in the Consolidated Statement of Operations for all periods presented. The PG Energy natural gas distribution division and Rhode Island operations of the New England Gas Company natural gas distribution division were historically reported within the Distribution segment.

Loss from discontinued operations before income taxes in the Consolidated Statement of Operations includes a loss for 2006 of $56.8 million recorded by the Company upon the sale of the assets of its PG Energy natural gas distribution division and the Rhode Island operations of its New England Gas Company natural gas distribution division. Significant components contributing to the loss include $19.4 million of asset impairment charges related to increases in PP&E during 2006, selling costs of $4.7 million, and charges associated with pre-closing

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arrangements between the Company and the buyers, principally consisting of $15.1 million of pension funding requirements and $5.8 million of premiums related to the early retirement of debt. An additional factor related to higher PP&E balances is the cessation of recording depreciation expense subsequent to approval of the Company's Board of Directors in January 2006 to dispose of the applicable assets.

The Company incurred $142.4 million of income tax expense in 2006 resulting from $379.8 million of non-deductible goodwill that had no tax basis. Additionally, the Company incurred $17.6 million of income tax expense as a result of the write-off of a tax-related regulatory asset.

See *Note 7 – Goodwill* for information related to the $175 million goodwill impairment charge recorded in 2005 related to the Company's discontinued operations.
The following table summarizes the combined results of operations that have been segregated and reported as discontinued operations in the Consolidated Statement of Operations.

	Years Ended December 31, 2006 (2)	2005
	(In thousands,except per share amounts)	
Operating revenues	$ 512,935	$ 752,549
Operating income (loss)	54,662	(106,073)
Loss from discontinued operations (1)	(152,952)	(132,413)
Net loss available from discontinued operations per share:		
Basic	$ (1.33)	$ (1.21)
Diluted	$ (1.30)	$ (1.17)

(1) Loss from discontinued operations does not include any allocation of corporate interest expense or other corporate costs.
(2) Represents results of operations for year 2006 through August 24, 2006.

20. Asset Retirement Obligations

Statement No. 143 requires an ARO to be recorded when a legal obligation to retire the asset exists. FIN No. 47 clarifies that an ARO should be recorded for all assets with legal retirement obligations, even if the enforcement of the obligation is contingent upon the occurrence of events beyond the company's control (*Conditional ARO*). The fair values of the AROs were calculated using an expected present value technique. This technique reflects assumptions such as removal and remediation costs, inflation and profit margins that third parties would demand to settle the amount of the future obligation. The Company did not include a market risk premium for unforeseeable circumstances in its fair value estimates because such a premium could not be reliably estimated.

Although a number of other assets in the Company's system are subject to agreements or regulations that give rise to an ARO or a Conditional ARO upon the Company's discontinued use of these assets, AROs were not recorded for most of these assets because the fair values of these AROs were not reliably estimable. The principal reason the fair values of these AROs were not subject to reliable estimation was because the lives of the underlying assets are indeterminate. Management has concluded that the Panhandle pipeline system, as a whole, and the SUGS natural gas gathering and processing system, as a whole, have indeterminate lives. In reaching this conclusion, management considered its intent for operating the systems, the economic life of the underlying assets, its past practices and industry practice.

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The Company intends to operate the pipeline and the natural gas gathering and processing systems indefinitely as a going concern. Individual component assets have been and will continue to be replaced, but the pipeline and the natural gas gathering and processing systems will continue in operation as long as supply and demand for natural gas exists. Based on the widespread use of natural gas in industrial and power generation activities and current estimates of recoverable reserves, management expects supply and demand to exist for the foreseeable future.

The Company has in place a rigorous repair and maintenance program that keeps the pipeline and the natural gas gathering and processing systems in good working order. Therefore, although some of the individual assets on the systems may be replaced, the pipeline and the natural gas gathering and processing systems themselves will remain intact indefinitely. AROs generally do not arise unless a pipeline or a facility (or portion thereof) is abandoned. The Company does not intend to make any such abandonments as long as supply and demand for natural gas remains relatively stable.
The following table is a general description of ARO and associated long-lived assets at December 31, 2007.

ARO Description	In Service Date	Long-Lived Assets	Amount
			(In thousands)
Retire offshore lateral lines	Various	Offshore lateral lines	$ 5,539
Other	Various	Mainlines, compressors and gathering plants	1,446

The following table is a reconciliation of the carrying amount of the ARO liability for the periods presented.

	Years Ended December 31, 2007	2006	2005
		(In thousands)	
Beginning balance	$ 10,535	$ 8,200	$ 5,657
Addition from Sid Richardson Energy Services acquisition	-	885	-
Incurred	2,314	1,189	2,371
Settled	(907)	(414)	(285)
Accretion expense	820	675	457
Ending balance	$ 12,762	$ 10,535	$ 8,200

21. Reportable Segments

The Company's reportable business segments are organized based on the way internal managerial reporting presents the results of the Company's various businesses to its executive management for use in determining the performance of the businesses and in allocating resources to the businesses, as well as based on similarities in economic characteristics, products and services, types of customers, methods of distribution and regulatory environment. The Company operates in three reportable segments.

The Transportation and Storage segment operations are conducted through Panhandle and the investment in Citrus. Through Panhandle, the Company is primarily engaged in the interstate transportation and storage of natural gas from the Gulf of Mexico, South Texas and the Panhandle regions of Texas and Oklahoma to major U.S. markets in the Midwest and Great Lakes regions. Panhandle also provides LNG terminalling and regasification services. Through its investment in Citrus, the Company has an interest in and operates Florida Gas. Florida Gas is primarily engaged in the interstate transportation of natural gas from South Texas through

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the Gulf Coast region to Florida. See the related discussion of the change in ownership interests of CCE Holdings on December 1, 2006 applicable to Florida Gas and Transwestern in *Note 3 – Acquisitions and Sales – CCE Holdings Transactions.*

The Company acquired Sid Richardson Energy Services on March 1, 2006, which represents the Gathering and Processing reportable segment. The Gathering and Processing segment is primarily engaged in connecting wells of natural gas producers to its gathering system, treating natural gas to remove impurities to meet pipeline quality specifications, processing natural gas for the removal of NGLs, and redelivering natural gas and NGLs to a variety of markets. Its operations are conducted through SUGS throughout Texas and in the southwestern United States. See *Note 3 – Acquisition and Sales – Acquisition of Sid Richardson Energy Services*.

The Distribution segment is primarily engaged in the local distribution of natural gas in Missouri and Massachusetts. The Company's discontinued operations relate to its PG Energy natural gas distribution division and the Rhode Island operations of its New England Gas Company natural gas distribution division. During the first quarter of 2006, the Company entered into definitive agreements to sell the assets of its PG Energy natural gas distribution division and the Rhode Island operations of its New England Gas Company natural gas distribution division. The Company completed the sales in August 2006. See *Note 19 – Discontinued Operations*.

Revenue included in the Corporate and other category is primarily attributable to PEI Power Corporation, which generates and sells electricity. PEI Power Corporation does not meet the quantitative threshold for segment reporting.

The Company evaluates operational and financial segment performance based on several factors, of which the primary financial measure is earnings before interest and taxes (*EBIT*), which is a non-GAAP measure. The Company defines EBIT as *Net earnings available for common stockholders*, adjusted for the following:

- items that do not impact net earnings from continuing operations, such as extraordinary items, discontinued operations and the impact of changes in accounting principles;
- income taxes;
- interest; and
- dividends on preferred stock.

EBIT may not be comparable to measures used by other companies and should be considered in conjunction with net earnings and other performance measures such as operating income or operating cash flow.

Sales of products or services between segments are billed at regulated rates or at market rates, as applicable. There were no material intersegment revenues during the years ended December 31, 2007, 2006 and 2005.

The following table sets forth certain selected financial information for the Company's segments for the years ended December 31, 2007, 2006 and 2005. Financial information for the Gathering and Processing segment reflects operations of SUGS beginning on its acquisition date of March 1, 2006. The Consolidated Statement of Operations segment information for all periods presented has been reclassified to distinguish between results of operations from continuing and discontinued operations. Segment information presented for expenditures of long-lived assets for the year ended December 31, 2005 has not been adjusted for discontinued operations.

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Segment Data	2007	2006	2005
		Years Ended December 31, (In thousands)	
Operating revenues from external customers:			
Transportation and Storage	$ 658,446	$ 577,182	$ 505,233
Gathering and Processing	1,221,747	1,090,216	-
Distribution	732,109	668,721	752,699
Total segment operating revenues	2,612,302	2,336,119	1,257,932
Corporate and other	4,363	4,025	8,950
	$ 2,616,665	$ 2,340,144	$ 1,266,882
Depreciation and amortization:			
Transportation and Storage	$ 85,641	$ 72,724	$ 62,171
Gathering and Processing	59,560	47,321	-
Distribution	30,251	30,353	29,447
Total segment depreciation and amortization	175,452	150,398	91,618
Corporate and other	2,547	1,705	944
	$ 177,999	$ 152,103	$ 92,562
Earnings (loss) from unconsolidated investments:			
Transportation and Storage	$ 99,222	$ 141,310	$ 70,618
Gathering and Processing	1,300	(188)	-
Corporate and other	392	248	124
	$ 100,914	$ 141,370	$ 70,742
Other income (expense), net:			
Transportation and Storage	$ 1,604	$ 3,354	$ 571
Gathering and Processing	140	1,571	-
Distribution	(1,902)	(2,130)	(2,598)
Total segment other income (expense), net	(158)	2,795	(2,027)
Corporate and other	(725)	37,123	(6,214)
	$ (883)	$ 39,918	$ (8,241)
Segment performance:			
Transportation and Storage EBIT	$ 391,029	$ 417,536	$ 281,344
Gathering and Processing EBIT	65,368	62,630	-
Distribution EBIT	70,568	41,883	61,698
Total segment EBIT	526,965	522,049	343,042
Corporate and other	151	14,324	(11,424)
Interest expense	203,146	210,043	128,470
Federal and state income taxes	95,259	109,247	50,052
Earnings from continuing operations	228,711	217,083	153,096
Loss from discontinued operations before income taxes	-	(2,369)	(111,588)
Federal and state income taxes	-	150,583	20,825
Loss from discontinued operations	-	(152,952)	(132,413)
Net earnings	228,711	64,131	20,683
Preferred stock dividends	17,365	17,365	17,365
Net earnings available for common stockholders	$ 211,346	$ 46,766	$ 3,318

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Segment Data	Years Ended December 31, 2007	2006
	(In thousands)	
Total assets:		
Transportation and Storage	$ 4,550,822	$ 3,874,318
Gathering and Processing	1,709,901	1,722,055
Distribution	1,020,460	1,016,491
Total segment assets	7,281,183	6,612,864
Corporate and other	116,730	169,926
Total consolidated assets	$ 7,397,913	$ 6,782,790

	Years Ended December 31, 2007	2006	2005
		(In thousands)	
Expenditures for long-lived assets:			
Transportation and Storage	$ 591,153	$ 244,821	$ 189,415
Gathering and Processing	48,633	35,101	-
Distribution	44,769	47,954	84,896
Total segment expenditures for long-lived assets	684,555	327,876	274,311
Corporate and other	4,173	4,798	2,306
Total consolidated expenditures for long-lived assets	$ 688,728	$ 332,674	$ 276,617

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Significant Customers and Credit Risk. The following tables provide summary information of significant customers for Panhandle and SUGS by applicable segment and on a consolidated basis for the periods presented. The Distribution segment has no single customer, or group of customers under common control, that accounted for ten percent or more of the Company's Distribution segment or consolidated operating revenues for the periods presented.

	Percent of Transportation and Storage Segment Revenues Years Ended December 31,			Percent of Consolidated Company Total Operating Revenues Years Ended December 31,		
Customer	**2007**	**2006**	**2005**	**2007**	**2006**	**2005**
BG LNG Services	28%	24%	17%	7%	6%	4%
ProLiance	11	12	16	3	3	4
Ameren Corp	9	10	11	2	3	3
Other top 10 customers	17	19	14	4	5	4
Remaining customers	35	35	42	9	8	10
Total percentage	100%	100%	100%	25%	25%	25%

	Percent of Gathering and Processing Segment Revenues Years Ended December 31,		Percent of Consolidated Company Total Operating Revenues Years Ended December 31,	
Customer	**2007**	**2006 (1)**	**2007**	**2006 (1)**
ConocoPhillips Company	16%	22%	8%	10%
BP Energy Company	6	11	3	5
Constellation Power Source	7	10	3	5
Other top 10 customers	34	22	16	10
Remaining customers	37	35	17	17
Total percentage	100%	100%	47%	47%

(1) Represents results from operations for the period subsequent to the March 1, 2006 acquisition.

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22. Accumulated Other Comprehensive Loss

The table below provides an overview of *Comprehensive income (loss)* for the periods indicated:

Other Comprehensive Income (Loss)	Year Ended December 31, 2007	2006	2005
		(In thousands)	
Net Earnings	$ 228,711	$ 64,131	$ 20,683
Other Comprehensive Income (Loss) Adjustments:			
Change in fair value of interest rate hedges, net of tax of $(5,241), $(745) and $73, respectively	(10,041)	(49)	108
Reclassification of unrealized gain on interest rate hedges into earnings, net of tax of $(13), $608 and $608, respectively	(4)	967	967
Realized gain (loss) on interest rate hedges, net of tax of $(1,488), $0 and $0, respectively	(2,366)	-	-
Reversal of minimum pension liability related to disposition, net of tax of $0, $16,004 and $0, respectively	-	26,331	-
Minimum pension liability adjustment, net of tax of $0, $4,128 and $1,064, respectively	-	6,803	1,771
Change in fair value of commodity hedges, net of tax of $(775), $7,466 and $0, respectively	(1,279)	12,360	-
Reclassification of unrealized gain on commodity hedges into earnings, net of tax of $(2,425), $(4,266) and $0, repectively	(3,997)	(7,084)	-
Actuarial gain and prior service credit (cost) relating to pension and other postretirement benefits, net of tax of $1,055, $0 and $0, respectively	3,597	-	-
Reclassification of actuarial gain and prior service credit (cost) relating to pension and other postretirement benefits into earnings, net of tax of $1,619, $0 and $0, respectively	3,397	-	-
Total other comprehensive income (loss)	(10,693)	39,328	2,846
Total comprehensive income	$ 218,018	$ 103,459	$ 23,529

The table below provides an overview of the components in *Accumulated other comprehensive loss* as of the periods indicated:

	Years Ended December 31, 2007	2006
	(In thousands)	
Interest rate hedges, net	$ (14,723)	$ (2,312)
Commodity hedges, net	-	5,276
Benefit Plans:		
Net actuarial loss and prior service costs, net - pensions	(17,907)	(26,678)
Net actuarial gain and prior service credit, net - other postretirement benefits	21,036	22,813
Total Accumulated other comprehensive loss, net of tax	$ (11,594)	$ (901)

23. Related Party Transactions

See *Note 9 – Unconsolidated Investments – Dividends* for information related to dividends received by the Company from its unconsolidated investments.

On November 5, 2004, SU Pipeline Management LP (*Manager*), a wholly-owned subsidiary of Southern Union, and PEPL entered into an

Administrative Services Agreement (*Management Agreement*) with CCE Holdings.

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Pursuant to the Management Agreement, Manager provided administrative services to CCE Holdings and its subsidiaries from November 17, 2004 to December 1, 2006. The Management Agreement was terminated on December 1, 2006 following the redemption of Transwestern as more fully discussed in *Note 3 – Acquisitions and Sales – CCE Holdings Transactions*.

Pursuant to the Management Agreement, Southern Union billed CCE Holdings $4.3 million in 2005 for management fees. No billings were made for management fees in 2006 under the Management Agreement. In years 2006 and 2005, Southern Union billed CCE Holdings $14 million and $12 million, respectively, for certain corporate costs provided under the Management Agreement prior to its termination on December 1, 2006 in conjunction with the transactions contemplated by the Redemption Agreement.

24. Stock-Based Compensation

Stock Options. Effective January 1, 2006, the Company adopted Statement No. 123R, using the modified prospective application method of transition, as defined in Statement No. 123R. Since the adoption of Statement No. 123R, the Company has recorded the grant date fair value of share-based payment arrangements, net of estimated forfeitures, as compensation expense using a straight-line basis over the awards' requisite service period. Under the modified prospective application method, Statement No. 123R applies to new awards and to awards modified, repurchased, or cancelled after December 31, 2005. Compensation cost for the portion of awards for which the requisite service has not been rendered that are outstanding as of December 31, 2005 is recognized as the requisite service is rendered on or after January 1, 2006. Additionally, no transition adjustment is generally permitted for the deferred tax assets associated with outstanding equity instruments, as these deferred tax assets will be recorded as a credit to *Premium on capital stock* when realized. No cumulative effect of a change in accounting principle was recognized upon adoption of Statement No. 123R.

The Company previously disclosed the fair value of stock options granted and the assumptions used in determining fair value pursuant to Statement No. 123, *Accounting for Stock-Based Compensation.* The Company historically used a Black-Scholes valuation model to determine the fair value of stock options granted. Stock options (either incentive stock options or non-qualified options) and SARs generally vest over a three-, four- or five-year period from the date of grant and expire ten years after the date of grant. The adoption of Statement No. 123R in 2006 reduced *Operating Income, Earnings from continuing operations before income taxes* and *Net earnings* by $2.4 million, $2.4 million and $1.9 million, respectively, or $0.02 per basic share and $0.02 per diluted share for the year ended December 31, 2006.

The fair value of each option award is estimated on the date of grant using a Black-Scholes option pricing model. The Company's expected volatilities are based on historical volatility of the Company's stock. To the extent that volatility of the Company's stock price increases in the future, the estimates of the fair value of options granted in the future could increase, thereby increasing share-based compensation expense in future periods. Additionally, the expected dividend yield is considered for each grant on the date of grant. The Company's expected term of options granted was derived from the average midpoint between vesting and the contractual term. In the future, as information regarding post-vesting termination becomes more accessible, the Company may change the method of deriving the expected term. This change could impact the fair value of options granted in the future. The risk-free rate is based on the U.S. Treasury yield curve in effect at the time of grant.

The following table represents the Black-Scholes estimated ranges under the Company plans for grants issued in the periods presented:

	Years ended December 31,		
	2007	2006	2005
Expected volatility	30.11% to 32.12%	32.90%	20.57% to 37.61%
Expected dividend yield	2.10%	1.43%	1.67%
Risk-free interest rate	3.70% to 3.89%	4.69%	3.76% to 4.63%
Expected life	6.00 to 7.50 years	6.00 years	0.75 to 6.50 years

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The following table provides information on stock options granted, exercised, canceled, outstanding and exercisable under the Second Amended 2003 Plan and the 1992 Plan for the years ended December 31, 2007, 2006 and 2005:

	Second Amended 2003 Plan		1992 Plan	
	Shares Under Option	Weighted Average Exercise Price	Shares Under Option	Weighted Average Exercise Price
Outstanding January 1, 2005	698,522	$ 16.83	2,390,705	$ 12.81
Granted	731,349	23.52	136,608	12.75
Exercised	(62,976)	16.83	(794,105)	12.47
Forfeited	(77,385)	16.83	(473,584)	12.45
Outstanding December 31, 2005	1,289,510	$ 20.62	1,259,624	$ 13.15
Granted	- (1)	-	-	-
Exercised	(121,137)	17.31	(521,289)	13.92
Forfeited	(157,894)	18.23	(23,139)	12.92
Outstanding December 31, 2006	1,010,479	$ 21.39	715,196	$ 12.60
Granted	717,098 (2)	28.48	-	-
Exercised	(98,027)	19.32	(176,515)	10.51
Forfeited	(97,875)	22.95	(1,979)	13.03
Outstanding December 31, 2007	1,531,675	$ 24.74	536,702	$ 13.28
Exercisable December 31, 2005	355,259	21.85	1,147,902	13.06
Exercisable December 31, 2006	533,363	22.38	715,196	12.60
Exercisable December 31, 2007	565,560	22.25	536,702	13.28

(1) Excludes 133,610 SARs which vest in equal increments on December 27, 2007 through 2009. Each SAR entitles the holder to shares of Southern Union's common stock equal to the fair market value of Southern Union's common stock in excess of $28.07 for each SAR on the applicable vesting date.
(2) Excludes 282,163 SARs which vest in equal increments on December 17, 2008 through 2010. Each SAR entitles the holder to shares of Southern Union's common stock equal to the fair market value of Southern Union's common stock in excess of $28.48 for each SAR on the applicable vesting date.

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The following table summarizes information about stock options outstanding under the Second Amended 2003 Plan and the 1992 Plan at December 31, 2007:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number of Options	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number of Options	Weighted Average Exercise Price
Second Amended 2003 Plan:					
16.82 - 20.00	242,135	6.11 years	$ 16.83	105,800	$ 16.83
20.01 - 25.00	572,442	7.70 years	23.41	459,760	23.50
25.01 - 28.48	717,098	9.97 years	28.48	-	-
	1,531,675	8.51 years	$ 24.74	565,560	$ 22.25
1992 Plan:					
12.63 - 14.66	536,702	1.50 years	$ 13.28	536,702	$ 13.28
	536,702	1.50 years	$ 13.28	536,702	$ 13.28

The weighted average remaining contractual life of options and SARs outstanding under the Second Amended 2003 Plan and the 1992 Plan at December 31, 2007 was 8.75 and 1.50 years, respectively. The weighted average remaining contractual life of options and SARs exercisable under the Second Amended 2003 Plan and the 1992 Plan at December 31, 2007 was 7.49 and 1.50 years, respectively. The aggregate intrinsic value of total options and SARs outstanding and exercisable at December 31, 2007 was $16.6 million and $12.9 million, respectively.

As of December 31, 2007, there was $11.1 million of total unrecognized compensation cost related to non-vested stock options and SARs compensation arrangements granted under the stock option plans. That cost is expected to be recognized over a weighted-average contractual period of 3.4 years. The total fair value of options and SARs vested as of December 31, 2007 was $8.2 million. Compensation expense recognized related to stock options and SARs totaled $1.5 million ($1.2 million, net of tax) for the year ended December 31, 2007 and $2.4 million ($1.9 million, net of tax) for the year ended December 31, 2006. Cash received from the exercise of stock options was $3.7 million for the year ended December 31, 2007.

The intrinsic value of options exercised during the year ended December 31, 2007 was approximately $4.9 million. The Company realized an additional tax benefit of approximately $1.7 million for the excess amount of deductions related to stock options over the historical book compensation expense multiplied by the statutory tax rate in effect, which has been reported as an increase in financing cash flows in the Consolidated Statement of Cash Flows.

Restricted Stock. The Company's Second Amended 2003 Plan also provides for grants of restricted stock equity units and restricted stock liability units. The Company settles restricted stock equity units with shares of common stock, and restricted stock liability units with cash. The restrictions associated with a grant of restricted stock equity units under the Second Amended 2003 Plan generally expire equally over a period of three years or in total after five years. Restrictions on certain grants made to non-employee directors and senior executives of the Company expire over a shorter time period, in certain cases less than one year, and may be subject to accelerated expiration over a shorter term if certain criteria are met. The restrictions associated with a grant of restricted stock liability units expire equally over a period of three years and are payable in cash at the vesting date.

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A summary of the activity of non-vested restricted stock equity awards as of December 31, 2007 is presented below:

Nonvested Restricted Stock Equity Units	Number of Restricted Shares Outstanding	Weighted-Average Grant-Date Fair-Value
Nonvested restricted shares at January 1, 2005	-	$ -
Granted	209,903	24.15
Vested	-	-
Forfeited	-	-
Nonvested restricted shares at December 31, 2005	209,903	$ 24.15
Granted	137,036	26.50
Vested	(146,335)	24.17
Forfeited	(31,820)	24.44
Nonvested restricted shares at December 31, 2006	168,784	$ 25.98
Granted	156,044	28.99
Vested	(111,322)	26.67
Forfeited	(12,336)	24.96
Nonvested restricted shares at December 31, 2007	201,170	$ 28.00

A summary of the activity of nonvested restricted stock unit liability awards as of December 31, 2007 is presented below:

Nonvested Restricted Stock Liability Units	Number of Restricted Stock Liability Units Outstanding	Weighted-Average Grant-Date Fair-Value
Nonvested restricted shares at December 31, 2005	-	$ -
Granted	108,869	28.07
Vested	-	-
Forfeited	-	-
Nonvested restricted shares at December 31, 2006	108,869	$ 28.07
Granted	143,460	28.49
Vested	(36,283)	28.07
Forfeited	(2,744)	28.07
Nonvested restricted shares at December 31, 2007	213,302	$ 28.35

As of December 31, 2007, there was $10.1 million of total unrecognized compensation cost related to non-vested, restricted stock equity units and restricted stock liability units compensation arrangements granted under the restricted stock plans. That cost is expected to be recognized over a weighted-average contractual period of 3 years. The total fair value of restricted stock equity and liability units that vested during the year ended December 31, 2007 was $4 million. Compensation expense recognized related to restricted stock equity and liability units totaled $3 million ($1.9 million, net of tax) for the year ended December 31, 2007, and $4.3 million ($2.7 million, net of tax) for the year ended December 31, 2006.

The Company settled the restricted stock liability awards vesting in 2007 with cash payments of $1.1 million.

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25. Subsequent Event

On February 8, 2008, the Company remarketed the 4.375% Senior Notes. The interest rate on the Senior Notes was reset to 6.089 percent per annum effective on and after February 19, 2008. The Senior Notes will mature on February 16, 2010. On February 19, 2008, the Company issued 3,693,240 shares of common stock for $100 million in conjunction with the remarketing of its 4.375% Senior Notes. For additional information, see *Note 10 – Stockholder's Equity – 2005 Equity Issances.*

26. Quarterly Operations (Unaudited)

The following table presents the operating results for each quarter of the year ended December 31, 2007:

	Quarters Ended			
	March 31	June 30	September 30	December 31
	(In thousands, except per share amounts)			
Operating revenues	$ 780,232	$ 588,049	$ 525,473	$ 722,911
Operating income	129,594	87,400	96,980	113,111
Earnings from continuing operations	78,721	50,975	45,283	53,732
Net earnings available for common stockholders	74,380	46,634	40,941	49,391
Diluted net earnings per share available for common stockholders:				
Continuing operations	$ 0.62	$ 0.39	$ 0.34	$ 0.41
Available for common stockholders	$ 0.62	$ 0.39	$ 0.34	$ 0.41

The following table presents the operating results for each quarter of the year ended December 31, 2006:

	Quarters Ended			
	March 31	June 30	September 30	December 31
	(In thousands, except per share amounts)			
Operating revenues	$ 547,166	$ 552,355	$ 564,418	$ 676,205
Operating income	102,847	69,792	69,961	112,485
Earnings from continuing operations	73,418	16,321	11,829	115,515
Net earnings (loss) from discontinued operations	24,529	(2,587)	(174,473)	(421)
Net earnings (loss) available for common stockholders	93,606	9,393	(166,985)	110,752
Diluted net earnings (loss) per share available for common stockholders:				
Continuing operations	$ 0.60	$ 0.10	$ 0.06	$ 0.92
Available for common stockholders	$ 0.82	$ 0.08	$ (1.42)	$ 0.92

The sum of EPS by quarter in the above tables may not equal the net earnings per common and common share equivalents for the applicable year due to variations in the weighted average common and common share equivalents outstanding used in computing such amounts.

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Report of Independent Registered Public Accounting Firm

To the Stockholders and Board of Directors
of Southern Union Company:

In our opinion, the accompanying consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Southern Union Company and its subsidiaries (the "Company") at December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting under Item 9A. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As discussed in Note 15 to the consolidated financial statements, the Company adopted the provisions of FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109", as of January 1, 2007. As discussed in Notes 2 and 14 to the consolidated financial statements, the Company adopted the recognition and disclosure provisions of FASB Statement No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans - an amendment of FASB Statement No. 87, 88, 106 and 132(R)", as of December 31, 2006.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
February 29, 2008

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Citrus Corp. and Subsidiaries
Consolidated Financial Statements
Years ended December 31, 2007, 2006 and 2005
with Report of Independent Registered Public Accounting Firm

Consolidated Financial Statements

Years ended December 31, 2007, 2006 and 2005

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Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Citrus Corp.:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, of stockholders' equity, of comprehensive income and of cash flows present fairly, in all material respects, the financial position of Citrus Corp. and subsidiaries (the "Company") at December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007 in conformity with the accounting principles generally accepted in the United States of America. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Notes 2 and 6 to the consolidated financial statements, the Company adopted the recognition and disclosure provisions of FASB Statement No. 158 "Employers' Accounting for Defined Pension and Other Postretirement Plans - an amendment of FASB Statements No. 87, 88, 106 and 132(R)," as of December 31, 2006.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
February 25, 2008

CITRUS CORP. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31, 2007	December 31, 2006
	(In thousands)	
ASSETS		
Current Assets		
Cash and cash equivalents	$ 3,572	$ 15,267
Accounts receivable, billed and unbilled, less allowances of $18 and $282, respectively	39,350	45,049
Materials and supplies	12,745	2,954
Exchange gas receivable	1,729	-
Other	2,248	1,025
Total Current Assets	59,644	64,295
Property, Plant and Equipment		
Plant in service	4,265,844	4,163,082
Construction work in progress	150,742	85,746
	4,416,586	4,248,828
Less accumulated depreciation and amortization	1,401,638	1,304,133
Property, Plant and Equipment, Net	3,014,948	2,944,695
Other Assets		
Unamortized debt expense	4,221	4,687
Regulatory assets	19,207	31,007
Other	10,838	76,429
Total Other Assets	34,266	112,123
Total Assets	$ 3,108,858	$ 3,121,113
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Current portion of long-term debt	$ 44,000	$ 84,000
Accounts payable - trade and other	33,422	25,070
Accounts payable - affiliated companies	8,416	2,823
Accrued interest	14,251	14,805
Accrued income taxes	7,599	2,375
Accrued taxes, other than income	5,437	9,332
Exchange gas payable	22,547	24,225
Capital accruals	22,636	22,185
Dividends payable	42,600	-
Other	7,600	6,526
Total Current Liabilities	208,508	191,341
Deferred Credits		
Deferred income taxes, net	763,364	777,404
Regulatory liabilities	14,842	14,256
Other	9,202	8,129
Total Deferred Credits	787,408	799,789

Long-Term Debt	909,810	836,882
Commitments and contingencies (Note 14)		
Stockholders' Equity		
Common stock, $1 par value; 1,000 shares authorized, issued and outstanding	1	1
Additional paid-in capital	634,271	634,271
Accumulated other comprehensive loss	(7,885)	(10,524)
Retained earnings	576,745	669,353
Total Stockholders' Equity	1,203,132	1,293,101
Total Liabilities and Stockholders' Equity	$ 3,108,858	$ 3,121,113

The accompanying notes are an integral part of these consolidated financial statements.

CITRUS CORP. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31, 2007	Year Ended December 31, 2006	Year Ended December 31, 2005
		(In thousands)	
Operating Revenues			
Transportation of natural gas	$ 495,513	$ 485,189	$ 476,049
Total Operating Revenues	495,513	485,189	476,049
Operating Expenses			
Operations and maintenance	82,058	77,941	78,829
Depreciation and amortization	100,634	98,653	91,125
Taxes, other than income taxes	29,618	34,765	34,306
Total Operating Expenses	212,310	211,359	204,260
Operating Income	283,203	273,830	271,789
Other Income (Expenses)			
Interest expense and related charges, net	(73,871)	(76,428)	(79,290)
Other, net	39,984	4,633	6,531
Total Other Income (Expenses), net	(33,887)	(71,795)	(72,759)
Income Before Income Taxes	249,316	202,035	199,030
Federal and State Income Tax Expense	92,224	75,960	75,086
Net Income	$ 157,092	$ 126,075	$ 123,944

The accompanying notes are an integral part of these consolidated financial statements.

CITRUS CORP. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

	Year Ended December 31, 2007	Year Ended December 31, 2006	Year Ended December 31, 2005
		(In thousands)	
Common Stock			
Balance, beginning and end of period	$ 1	$ 1	$ 1
Additional Paid-in Capital			
Balance, beginning and end of period	634,271	634,271	634,271
Accumulated Other Comprehensive Loss			
Balance, beginning of period	(10,524)	(13,162)	(15,800)
Recognition in earnings of previously deferred net losses related to derivative instruments used as cash flow hedges	2,639	2,638	2,638
Balance, end of period	(7,885)	(10,524)	(13,162)
Retained Earnings			
Balance, beginning of period	669,353	668,678	665,934
Net income	157,092	126,075	123,944
Dividends (1)	(249,700)	(125,400)	(121,200)
Balance, end of period	576,745	669,353	668,678
Total Stockholders' Equity	$ 1,203,132	$ 1,293,101	$ 1,289,788

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended December 31, 2007	Year Ended December 31, 2006	Year Ended December 31, 2005
		(In thousands)	
Net income	$ 157,092	$ 126,075	$ 123,944
Recognition in earnings of previously deferred net losses related to derivative instruments used as cash flow hedges	2,639	2,638	2,638
Total Comprehensive Income	$ 159,731	$ 128,713	$ 126,582

(1) Includes $42.6 million in Dividends Payable, declared in December 2007, payable in January, 2008 and which was paid on January 18, 2008. (See Note 7 - Related Party Transaction)

The accompanying notes are an integral part of these consolidated financial statements.

CITRUS CORP. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2007	Year Ended December 31, 2006	Year Ended December 31, 2005
		(In thousands)	
Cash flows provided by operating activities			
Net income	$ 157,092	$ 126,075	$ 123,944
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	100,634	98,653	91,125
Amortization of hedge loss in other comprehensive income	2,639	2,638	2,638
Amortization of discount and swap hedge loss in long term debt	528	527	530
Amortization of regulatory assets and other deferred charges	1,250	3,274	3,380
Amortization of debt costs	994	1,048	1,053
Deferred income taxes	(12,277)	18,629	12,740
Allowance for funds used during construction	(4,683)	(1,630)	(1,441)
Gain on sale of assets	-	-	(1,236)
Changes in operating assets and liabilities:			
Accounts receivable	5,699	(3,327)	403
Accounts payable	11,950	(3,316)	(10,567)
Accrued interest	(554)	(286)	(324)
Accrued income tax	5,224	3,247	(7,204)
Other current assets and liabilities	(8,944)	18,749	3,234
Other long-term assets and liabilities	74,668	(24,627)	36,140
Net cash provided by operating activities	334,220	239,654	254,415
Cash flows used in investing activities			
Capital expenditures	(175,370)	(106,023)	(37,610)
Allowance for funds used during construction	4,683	1,630	1,441
Proceeds from sale of assets	-	-	1,715
Net cash used in investing activities	(170,687)	(104,393)	(34,454)
Cash flows used in financing activities			
Dividends paid	(207,100)	(125,400)	(121,200)
Net (payments) borrowings on the revolving credit facilities	76,400	(2,000)	(75,000)
Long-term debt finance costs	(528)	-	-
Payments on long-term debt	(44,000)	(14,000)	(14,000)
Net cash used in financing activities	(175,228)	(141,400)	(210,200)
Net increase (decrease) in cash and cash equivalents	(11,695)	(6,139)	9,761
Cash and cash equivalents, beginning of period	15,267	21,406	11,645
Cash and cash equivalents, end of period	$ 3,572	$ 15,267	$ 21,406
Supplemental disclosure of cash flow information			
Interest paid (net of amounts capitalized)	$ 72,439	$ 72,067	$ 74,714
Income tax paid	$ 103,589	$ 56,814	$ 66,954

The accompanying notes are an integral part of these consolidated financial statements.

CITRUS CORP. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Corporate Structure

Citrus Corp. (Citrus, the Company), a holding company formed in 1986, owns 100 percent of the membership interest in Florida Gas Transmission Company, LLC (Florida Gas), and 100 percent of the stock of Citrus Trading Corp. (Trading) and Citrus Energy Services, Inc. (CESI), collectively the Company. At December 31, 2007, the stock of Citrus was owned 50 percent by El Paso Citrus Holdings, Inc. (EPCH), a wholly-owned subsidiary of El Paso Corporation (El Paso), and 50 percent by CrossCountry Citrus, LLC (CCC), a wholly-owned subsidiary of CrossCountry Energy, LLC (CrossCountry). In November 2007, Southern Natural Gas Company (Southern), whose parent is El Paso, distributed EPCH to El Paso. CrossCountry was a wholly-owned subsidiary of Enron Corp. (Enron) and certain of its subsidiary companies. Effective November 17, 2004, CrossCountry became a wholly-owned subsidiary of CCE Holdings, LLC (CCE Holdings), which was a joint venture owned by subsidiaries of Southern Union Company (Southern Union) (50 percent), GE Commercial Finance Energy Financial Services (GE) (approximately 30 percent) and four minority interest owners (approximately 20 percent in the aggregate).

On December 1, 2006, a series of transactions were completed which resulted in Southern Union increasing its indirect ownership interest in Citrus from 25 percent to 50 percent. On September 14, 2006, Energy Transfer Partners, L.P. (Energy Transfer), an unaffiliated company, entered into a definitive purchase agreement to acquire the 50 percent interest in CCE Holdings from GE and other investors. At the same time, Energy Transfer and CCE Holdings entered into a definitive redemption agreement, pursuant to which Energy Transfer's 50 percent ownership interest in CCE Holdings would be redeemed in exchange for 100 percent of the equity interest in Transwestern Pipeline Company, LLC (TW) (Redemption Agreement). Upon closing of the Redemption Agreement on December 1, 2006, Southern Union became the indirect owner of 100 percent of CCE Holdings, whose principal remaining asset was its 50 percent interest in Citrus, with the remaining 50 percent of Citrus continuing to be owned by EPCH.

Florida Gas, an interstate natural gas pipeline extending from South Texas to South Florida, is engaged in the interstate transmission of natural gas and is subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC).

On September 1, 2006, Florida Gas converted its legal entity type from a corporation to a limited liability company, pursuant to the Delaware Limited Liability Company Act.

(2) Significant Accounting Policies

Basis of Presentation – The Company's consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America *(GAAP)*.

Regulatory Accounting **–** Florida Gas' accounting policies generally conform to Financial Accounting Standards Board (*FASB*) Statement No. 71, *Accounting for the Effects of Certain Types of Regulation (Statement No. 71)*. Accordingly, certain assets and liabilities that result from the regulated ratemaking process are recorded that would not be recorded under GAAP for non-regulated entities.

Revenue Recognition – Revenues consist primarily of fees earned from gas transportation services. Reservation revenues are based on contracted rates and capacity reserved by the customers and are recognized monthly. For interruptible or volumetric based services, commodity revenues are recorded upon the delivery of natural gas to the agreed upon delivery point. Revenues for all services are generally based on the thermal quantity of gas delivered or subscribed at a rate specified in the contract.

Because Florida Gas is subject to FERC regulations, revenues collected during the pendency of a rate proceeding may be required by the FERC to be refunded in the final order. Florida Gas establishes reserves for such potential refunds, as appropriate. There were no reserves for potential rate refund at December 31, 2007 and 2006, respectively.

Derivative Instruments – The Company follows FASB Statement No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended, (Statement No. 133) to account for derivative and hedging activities. In accordance with this statement, all derivatives are recognized on the Consolidated Balance Sheets

CITRUS CORP. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

at their fair value. On the date the derivative contract is entered into, the Company designates the derivative as (i) a hedge of the fair value of a recognized asset or liability or of an unrecognized firm commitment (*a fair value hedge*); (ii) a hedge of a forecasted transaction or the variability of cash flows to be received or paid in conjunction with a recognized asset or liability (*a cash flow hedge*); or (iii) an instrument that is held for trading or non-hedging purposes (*a trading or non-hedging instrument*). For derivatives treated as a fair value hedge, the effective portion of changes in fair value is recorded as an adjustment to the hedged item. The ineffective portion of a fair value hedge is recognized in earnings if the short cut method of assessing effectiveness is not used. Upon termination of a fair value hedge of a debt instrument, the resulting gain or loss is amortized to earnings through the maturity date of the debt instrument. For derivatives treated as a cash flow hedge, the effective portion of changes in fair value is recorded in *Accumulated Other Comprehensive Loss* until the related hedge items impact earnings. Any ineffective portion of a cash flow hedge is reported in current period earnings. For derivatives treated as trading or non-hedging instruments, changes in fair value are reported in current-period earnings. Fair value is determined based upon quoted market prices and mathematical models using current and historical data. As of December 31, 2007, the Company does not have any hedges in place as it is only amortizing previously terminated hedges.

Property, Plant and Equipment – Property, Plant and Equipment consists primarily of natural gas pipeline and related facilities and is recorded at its original cost. Florida Gas capitalizes direct costs, such as labor and materials, and indirect costs, such as overhead and cost of funds, both interest and an equity return component (see third following paragraph). Costs of replacements and renewals of units of property are capitalized. The original cost of units of property retired are charged to accumulated depreciation, net of salvage and removal costs. Florida Gas charges to maintenance expense the costs of repairs and renewal of items determined to be less than units of property.

The Company amortized that portion of its investment in Florida Gas property which is in excess of historical cost (acquisition adjustment) on a straight-line basis at an annual composite rate of 1.6 percent based upon the estimated remaining useful life of the pipeline system.

Florida Gas has provided for depreciation of assets, on a straight-line basis, at an annual composite rate of 2.77 percent, 2.78 percent and 2.56 percent for the years ended December 31, 2007, 2006 and 2005, respectively.

The recognition of an allowance for funds used during construction (AFUDC) is a utility accounting practice with calculations under guidelines prescribed by the FERC and capitalized as part of the cost of utility plant. It represents the cost of capital invested in construction work-in-progress. AFUDC has been segregated into two component parts – borrowed funds and equity funds. The allowance for borrowed and equity funds used during construction, including related gross up, totaled $10.3 million, $3.4 million and $1.4 million for the years ended December 31, 2007, 2006 and 2005, respectively. AFUDC borrowed is included in Interest Expense and AFUDC equity is included in Other Income in the accompanying statements of income.

Asset Retirement Obligations – The Company applies the provisions of *FASB Statement No. 143, Accounting for Asset Retirement Obligations* to record a liability for the estimated removal costs of assets where there is a legal obligation associated with removal. Under this standard, the liability is recorded at its fair value, with a corresponding asset that is depreciated over the remaining useful life of the long-lived asset to which the liability relates. An ongoing expense will also be recognized for changes in the value of the liability as a result of the passage of time.

FASB Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations (FIN No. 47) issued by the FASB in March 2005 clarifies that the term “conditional asset retirement obligation” as used in FASB Statement No. 143, *Accounting for Asset Retirement Obligations*, refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Accordingly, an entity is required to recognize a liability for the fair value of a conditional asset retirement obligation (ARO) when incurred, if the fair value of the liability can be reasonably estimated. FIN No. 47 provides guidance for assessing whether sufficient information is available to record an estimate. This interpretation was effective for the Company beginning on December 31, 2005. Upon adoption of FIN No. 47, Florida Gas recorded an increase in plant in service and a liability for an ARO of $0.5 million. This new asset and liability related to obligations associated with the removal and disposal of asbestos and asbestos containing materials on Florida Gas’ pipeline system. The ARO asset at December 31, 2007 had a net book value of $0.5 million.

CITRUS CORP. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The table below provides a reconciliation of the carrying amount of the ARO liability for the period indicated:

	Year Ended December 31, 2007	Year Ended December 31, 2006	Year Ended December 31, 2005
		(In thousands)	
Beginning balance	$ 481	$ 493	$ -
Incurred	-	-	493
Settled	(37)	(36)	-
Accretion Expense	27	24	-
Ending balance	$ 471	$ 481	$ 493

Asset Impairment – The Company applies the provisions of *FASB No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets,* to account for impairments on long-lived assets. Impairment losses are recognized for long-lived assets used in operations when indicators of impairment are present and the undiscounted cash flows are not sufficient to recover the assets' carrying value. The amount of impairment is measured by comparing the fair value of the asset to its carrying amount.

Exchange Gas – Gas imbalances occur as a result of differences in volumes of gas received and delivered by a pipeline system. These imbalances due to or from shippers and operators are valued at an appropriate index price. Imbalances are settled in cash or made up in-kind subject to terms of Florida Gas' tariff, and generally do not impact earnings.

Environmental Expenditures (Note 12) – Expenditures that relate to an existing condition caused by past operations, and do not contribute to current or future generation, are expensed. Environmental expenditures relating to current or future revenues are expensed or capitalized as appropriate based on the nature of the cost incurred. Liabilities are recorded when environmental assessments and/or clean ups are probable and the cost can be reasonably estimated. Remediation obligations are not discounted because the timing of future cash flow streams is not predictable.

Cash and Cash Equivalents – Cash equivalents consist of highly liquid investments with original maturities of three months or less. The carrying amount of cash and cash equivalents approximates fair value because of the short maturity of these investments.

Materials and Supplies – Materials and supplies are valued at the lower of cost or market value. Materials transferred out of warehouses are priced at average cost. Materials and supplies include spare parts which are critical to the pipeline system operations and are valued at the lower of cost or market.

Fuel Tracker – A liability is recorded for net volumes of gas owed to customers collectively. Whenever fuel is due from customers from prior under recovery based on contractual and specific tariff provisions an asset is recorded. Gas owed to or from customers is valued at market. Changes in the balances have no effect on the consolidated income of the Company.

Income Taxes (Note 4) – Income taxes are accounted for under the asset and liability method in accordance with the provisions of FASB Statement No. 109, *Accounting for Income Taxes*. Under this method, deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis. Deferred tax assets and liabilities are measured using enacted tax rates in effect for the year in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rate is recognized in income in the period that includes the enactment date. Valuation allowances are established when necessary to reduce deferred tax assets to the amounts more likely than not to be realized.

CITRUS CORP. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The determination of the Company's provision for income taxes requires significant judgment, use of estimates, and the interpretation and application of complex tax laws. Significant judgment is required in assessing the timing and amounts of deductible and taxable items. Reserves are established when, despite management's belief that the Company's tax return positions are fully supportable, management believes that certain positions may be successfully challenged. When facts are circumstances change, these reserves are adjusted through the provision for income taxes.

Accounts Receivable – The Company establishes an allowance for doubtful accounts on accounts receivable based on the expected ultimate recovery of these receivables. The Company considers many factors including historical customer collection experience, general and specific economic trends and known specific issues related to individual customers, sectors and transactions that might impact collectibility. Unrecovered accounts receivable charged against the allowance for doubtful accounts were $0.3 million, nil and nil in the years ended December 31, 2007, 2006 and 2005, respectively.

Pensions and Postretirement Benefits – Effective December 31, 2006, the Company adopted the recognition and disclosure provisions of FASB Statement No. 158, *"Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans – an amendment of FASB Statements No. 87, 88, 106, and 132(R)" (Statement No. 158)*. Statement No. 158 requires employers to recognize in their balance sheets the overfunded or underfunded status of defined benefit postretirement plans, measured as the difference between the fair value of the plan assets and the benefit obligation. Each overfunded plan is recognized as an asset and each underfunded plan is recognized as a liability. Employers must recognize the change in the funded status of the plan in the year in which the change occurs through *Accumulated Other Comprehensive Loss* in stockholders' equity. Effective for years beginning after December 15, 2008 (with early adoption permitted), Statement No. 158 also requires plan assets and benefit obligations to be measured as of the employers' balance sheet date. The Company has not yet adopted the measurement provisions of Statement No. 158.

Prior to adoption of the recognition provisions of Statement No. 158, the Company accounted for its defined benefit postretirement plans under FASB Statement No. 106, *"Employers' Accounting for Postretirement Benefits Other Than Pensions (Statement No. 106)."* Statement No. 106 required that the liability recorded should represent the actuarial present value of all future benefits attributable to an employee's service rendered to date. Under Statement No. 106, changes in the funded status were not immediately recognized; rather they were deferred and recognized ratably over future periods. Upon adoption of the recognition provisions of Statement No. 158, the Company recognized the amounts of these prior changes in the funded status of its postretirement benefit plans. The Company's plan is in an overfunded position as of December 31, 2007. As the plan assets are derived through rates charged to customers, under Statement No. 71, to the extent the Company has collected amounts in excess of what is required to fund the plan, the Company has an obligation to refund the excess amounts to customers through rates. As such, the Company recorded the previously unrecognized changes in the funded status (i.e., actuarial gains) as a regulatory liability and not as an adjustment to *Accumulated Other Comprehensive Loss*.

Use of Estimates – The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

New Accounting Principles

Accounting Principles Not Yet Adopted.

FIN 48," Accounting for Uncertainty in Income Taxes - an Interpretation of FASB Statement 109" (FIN 48 or the Interpretation): Issued by the FASB in June 2006, this Interpretation clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with FASB Statement No. 109, *Accounting for Income Taxes*. FIN 48 prescribes a recognition and measurement threshold attributable for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosures and transition. FIN 48 is effective for fiscal years beginning after December 15, 2006, for public enterprises and December 15, 2007, for nonpublic enterprises,

CITRUS CORP. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

such as Citrus. The Company has determined the implementation of this Statement will not have a material impact on its consolidated financial statements.

FSP No. FIN 48-1, "Definition of 'Settlement' in FASB Interpretation No. 48" (FIN 48-1): Issued by the FASB in May 2007, FIN 48-1 provides guidance on how an enterprise should determine whether a tax position is effectively settled for the purpose of recognizing previously unrecognized tax benefits.

FASB Statement No. 157, "Fair Value Measurements" (FASB Statement No. 157 or the Statement)**:** Issued by the FASB in September 2006, this Statement defines fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements. Where applicable, this Statement simplifies and codifies related guidance within GAAP. Except for certain non financial assets and liabilities more fully discussed in FSP No. FAS 157-2, "*Effective Date of FASB Statement No. 157*" (*FSP No. FAS 157*-2) which was issued by the FASB in February 2008, this Statement is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. For those non financial assets and liabilities deferred pursuant to FSP No. FAS 157-2, this Statement is effective for financial statements for fiscal years beginning after November 15, 2008. The Company is currently evaluating the impact of this Statement on its consolidated financial statements.

FASB Statement No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities – Including an Amendment of FASB Statement No. 115": Issued by the FASB in February 2007, this Statement permits entities to choose to measure many financial instruments and certain other items at fair value that are not currently required to be measured at fair value. Unrealized gains and losses on items for which the fair value option has been elected are reported in earnings. The Statement does not affect any existing accounting literature that requires certain assets and liabilities to be carried at fair value. The Statement is effective for fiscal years beginning after November 15, 2007. At January 1, 2008, the Company did not elect the fair value option under the Statement and, therefore, there was no impact to the Company's consolidated financials statements.

FASB Statement No. 141 (revised), "*Business Combinations".* Issued by the FASB in December 2007, this Statement changes the accounting for business combinations including the measurement of acquirer shares issued in consideration for a business combination, the recognition of contingent consideration, the accounting for preacquisition gain and loss contingencies, the recognition of capitalized in-process research and development costs, the accounting for acquisition-related restructuring cost accruals, the treatment of acquisition related transaction costs and the recognition of changes in the acquirer's income tax valuation allowance. The Statement is effective for fiscal years beginning after December 15, 2008, with early adoption prohibited.

FASB Statement No. 160, "*Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51".* Issued by the FASB in December 2007, this Statement changes the accounting for noncontrolling (minority) interests in consolidated financial statements including the requirements to classify noncontrolling interests as a component of consolidated stockholders' equity, and the elimination of minority interest accounting in results of operations with earnings attributable to noncontrolling interests reported as part of consolidated earnings. Additionally, the Statement revises the accounting for both increases and decreases in a parent's controlling ownership interest. The Statement is effective for fiscal years beginning after December 15, 2008, with early adoption prohibited. The Company is currently evaluating the impact of this statement on its consolidated financial statements.

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(3) Long Term Debt

The table below sets forth the long-term debt of the Company as of the dates indicated:

	Years Due	December 31, 2007 Book Value	December 31, 2007 Fair Value	December 31, 2006 Book Value	December 31, 2006 Fair Value
		(In thousands)			
Citrus					
8.490% Senior Notes	2007-2009	$ 60,000	$ 63,572	$ 90,000	$ 95,011
Revolving Credit Agreement Citrus	2012	62,400	62,400	-	-
FGT					
9.750% Senior B Notes	1999-2008	6,500	6,736	13,000	13,663
10.110% Senior C Notes	2009-2013	70,000	82,282	70,000	82,773
9.190% Senior Notes	2005-2024	127,500	158,843	135,000	167,004
7.625% Senior Notes	2010	325,000	353,352	325,000	348,137
7.000% Senior Notes	2012	250,000	277,281	250,000	271,893
Revolving Credit Agreement FGT	2007	-	-	40,000	40,000
Revolving Credit Agreement FGT	2012	54,000	54,000	-	-
Total debt outstanding		$ 955,400	$ 1,058,466	$ 923,000	$ 1,018,481
Current portion of long-term debt		(44,000)		(84,000)	
Unamortized Debt Discount and Swap Loss		(1,590)		(2,118)	
Total long-term debt		$ 909,810		$ 836,882	

Annual maturities of long-term debt outstanding as of the date indicated were as follows:

Year	December 31, 2007 (In thousands)
2008	$ 44,000
2009	51,500
2010	346,500
2011	21,500
2012	387,900
Thereafter	104,000
	$ 955,400

On August 13, 2004 Florida Gas entered into a Revolving Credit Agreement (“2004 Revolver”) with an initial commitment level of $50 million, subsequently increased by $125 million to $175 million. Since that time, Florida Gas has routinely utilized the 2004 Revolver to fund working capital needs. On December 31, 2006, the amount drawn under the 2004 Revolver was $40 million, with a weighted average interest rate of 6.08 percent (based on LIBOR plus 0.70 percent). Additionally, a commitment fee of 0.15 percent is payable quarterly on the unused portion of the commitment balance. The 2004 Florida Gas Revolver terminated in August 2007 and was replaced by a new revolving credit agreement at Florida Gas in the amount of $300 million (“2007 Florida Gas Revolver”), which will mature on August 16, 2012. The 2007 Florida Gas Revolver

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requires interest based on LIBOR plus a margin tied to the debt rating of the Company's senior unsecured debt, currently 0.28 percent, and has a facility fee of 0.07 percent. As of December 31, 2007, the amount drawn under the 2007 Florida Gas Revolver was $54 million with a weighted average interest rate of 5.30 percent (based on LIBOR plus 0.28 percent).

Also on August 16, 2007, Citrus entered into a revolving credit facility in the amount of $200 million ("2007 Citrus Revolver"), which will mature on August 16, 2012. This facility will enable Citrus to meet its funding needs and repay its debt maturities. As of December 31, 2007, the amount drawn under the 2007 Citrus Revolver was $62.4 million with a weighted average interest rate of 5.22 percent (based on LIBOR plus 0.28 percent), and has a facility fee of 0.07 percent. Issuance costs for the 2007 Florida Gas Revolver and 2007 Citrus Revolver were $0.3 million and $0.2 million, respectively at December 31, 2007.

The book value of the 2004 Revolver, 2007 Florida Gas Revolver, and 2007 Citrus Revolver approximates their market value given the variable rate of interest. Estimated fair value amounts of other long-term debt were obtained from independent parties, and are based upon market quotations of similar debt at interest rates currently available. Judgment is required in interpreting market data to develop the estimates of fair value. Accordingly, the estimates determined as of December 31, 2007 and 2006 are not necessarily indicative of the amounts the Company could have realized in current market exchanges.

The agreements relating to Florida Gas' debt include, among other things, restrictions as to the payment of dividends and maintaining certain restrictive financial covenants, including a required ratio of consolidated funded debt to total capitalization.

Under the terms of its debt agreements, Florida Gas may incur additional debt to refinance maturing obligations if the refinancing does not increase aggregate indebtedness, and thereafter, if Citrus' and Florida Gas' consolidated debt does not exceed specific debt to total capitalization ratios, as defined in certain debt instruments. Incurrence of additional indebtedness to refinance the current maturities would not result in a debt to capitalization ratio exceeding these limits.

All of the debt obligations of Citrus and Florida Gas have events of default that contain commonly used cross-default provisions. An event of default by either Citrus or Florida Gas on any of their borrowed money obligations, in excess of certain thresholds which is not cured within defined grace periods, would cause the other debt obligations of Citrus and Florida Gas to be accelerated.

(4) Income Taxes

The principal components of the Company's net deferred income tax liabilities as of the dates indicated were as follows:

	December 31, 2007	December 31, 2006
	(In thousands)	
Deferred income tax asset		
Regulatory and other reserves	$ 5,554	$ 8,595
	5,554	8,595
Deferred income tax liabilities		
Depreciation and amortization	759,576	742,566
Deferred charges and other assets	-	27,981
Regulatory costs	4,717	9,298
Other	4,625	6,154
	768,918	785,999
Net deferred income tax liabilities	$ 763,364	$ 777,404

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Total income tax expense for the periods indicated was as follows:

	Year Ended December 31, 2007	Year Ended December 31, 2006	Year Ended December 31, 2005
		(In thousands)	
Current Tax Provision			
Federal	$ 99,083	$ 52,135	$ 53,526
State	5,418	5,196	8,820
	104,501	57,331	62,346
Deferred Tax Provision			
Federal	(14,531)	15,863	11,079
State	2,254	2,766	1,661
	(12,277)	18,629	12,740
Total income tax expense	$ 92,224	$ 75,960	$ 75,086

The differences between taxes computed at the U.S. federal statutory rate of 35 percent and the Company's effective tax rate for the periods indicated are as follows:

	Year Ended December 31, 2007	Year Ended December 31, 2006	Year Ended December 31, 2005
		(In thousands)	
Statutory federal income tax provision	$ 87,261	$ 70,712	$ 69,661
State income taxes, net of federal benefit	4,986	5,176	6,813
Other	(23)	72	(1,388)
Income tax expense	$ 92,224	$ 75,960	$ 75,086
Effective Tax Rate	37.0%	37.6%	37.7%

The Company files a consolidated federal income tax return separate from that of its stockholders.

(5) Employee Benefit Plans

The employees of the Company were covered under Enron's employee benefit plans until November 2004.

Enron maintained a pension plan that was a noncontributory defined benefit plan, the Enron Corp. Cash Balance Plan (the Cash Balance Plan), covering certain Enron employees in the United States and certain employees in foreign countries. The basic benefit accrual was 5 percent of eligible annual base pay. In 2003 the Company recognized its portion of the expected Cash Balance Plan settlement by recording a $9.6 million current liability, which was cash settled in 2005 (Note 7), and a charge to operating expense. In 2004, with the settlement of the rate case (Note 8), Florida Gas recognized a regulatory asset for its portion, $9.3 million, with a reduction to operating expense. Per the rate case settlement Florida Gas will amortize, over five years retroactive to April 1, 2004, its allocated share of costs to fully fund and terminate the Cash Balance Plan. Amortization recorded was $1.9 million, $1.8 million and $1.9 million for the years ended December 31, 2007,

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2006 and 2005, respectively. At December 31, 2007 and 2006 the remaining regulatory asset balance was \$2.3 million and \$4.2 million, respectively (Note 10).

Effective November 1, 2004 all employees of the Company were transferred to an affiliated entity, CrossCountry Energy Services, LLC (CCES) and during November 2004, employee insurance coverage migrated (without lapse) from Enron plans to new CCES welfare and benefit plans. Effective March 1, 2005 essentially all such employees were transferred to Florida Gas and became eligible at that time to participate in employee welfare and benefit plans adopted by Florida Gas.

Effective March 1, 2005 Florida Gas adopted the Florida Gas Transmission Company 401(k) Savings Plan (the Plan). All employees of Florida Gas are eligible to participate and, within one Plan, may contribute up to 50 percent of pre-tax compensation, subject to IRS limitations. This Plan allows additional "catch-up" contributions by participants over age 50, and allows Florida Gas to make discretionary profit sharing contributions for the benefit of all participants. Florida Gas matched 50 percent of participant contributions under this Plan up to a maximum of four percent of eligible compensation through December 31, 2007. The matching was increased effective January 1, 2008 to 100 percent of the first two percent and 50 percent of the next three percent of the participant's compensation paid into the Plan. Participants vest in such matching and any profit sharing contributions at the rate of 20 percent per year, except that participants with five years of service at the date of adoption of the Plan were immediately vested. Administrative costs of the Plan and certain asset management fees are paid from Plan assets. Florida Gas' expensed its contribution of \$0.3 million, \$0.4 million, and \$0.3 million for the years ended December 31, 2007, 2006, and 2005 respectively.

Other Post – Employment Benefits

Prior to December 1, 2004 Florida Gas was a participating employer in the Enron Gas Pipelines Employee Benefit Trust (the Trust), a voluntary employees' beneficiary association (VEBA) under Section 501(c)(9) of the Internal Revenue Code of 1986, as amended (Tax Code), which provided certain post-retirement medical, life insurance and dental benefits to employees of Florida Gas and certain other Enron affiliates pursuant to the Enron Corp. Medical Plan and the Enron Corp. Medical Plan for Inactive Participants. Enron has made the determination that it will partition the Trust and distribute the assets and liabilities of the Trust among the participating employers of the Trust on a pro rata basis according to the contributions and liabilities associated with each participating employer. The Trust Committee has final approval on allocation methodology for the Trust assets. It is estimated that Florida Gas will receive approximately \$6.8 million from the Trust, including an estimated investment return as early as first quarter 2008. Enron filed a motion in the Enron bankruptcy proceedings on July 22, 2003 which was stayed and then refiled and amended on June 17, 2005 and again refiled and amended on December 1, 2006 which provides that each participating employer expressly assumes liability for its allocable portion of retiree benefits and releases Enron from any liability with respect to the Trust in order to receive the assets of the Trust. On June 7, 2005 a class action suit captioned *Lou Geiler et al v. Robert W. Jones*, *et al.,* was filed in United States District Court for the District of Nebraska by, among others, former employees of Northern Natural Gas Company (Northern) on behalf of the participants in the Northern Medical and Dental Plan for Retirees and Surviving Spouses against former and present members of the Trust Committee, the Trustee and the participating employers of the Trust, including Florida Gas, claiming the Trust Committee and the Trustee have violated their fiduciary duties under ERISA and seeking a declaration from the Court binding on all participating employers of an accounting and distribution of the assets held in the Trust and a complete and accurate listing of the individuals properly allocated to Northern from the Enron Plan. On the same date essentially the same group filed a motion in the Enron bankruptcy proceedings to strike the Enron motion from further consideration. On February 6, 2006 the Nebraska action was dismissed. The plaintiffs filed an appeal of the dismissal on March 8, 2006. An agreement was reached on the conditions of the partition of the Trust among the VEBA participating employers, Enron and the Trust Committee and approved by the Enron bankruptcy court on December 21, 2006. As a result, the Nebraska action appeal was dismissed on January 25, 2007.

During the period December 1, 2004 through February 28, 2005, following Florida Gas' November 17, 2004 acquisition by CCE Holdings, coverage to eligible employees and their eligible dependents was provided by CrossCountry Energy Retiree Health Plan, which provides only medical benefits. Florida Gas continues to provide certain retiree benefits through employer contributions to a qualified contribution plan, with the amounts generally varying based on age and years of service.

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Effective March 1, 2005 such benefits are provided under an identical plan sponsored by Florida Gas as a single employer post-retirement benefit plan.

With regard to its sponsored plan, Florida Gas has entered into a VEBA trust (the "VEBA Trust") agreement with JPMorgan Chase Bank Trust Company as trustee. The VEBA Trust has established or adopted plans to provide certain post-retirement life, health, accident and other benefits. The VEBA Trust is a voluntary employees' beneficiary association under Section 501(c)(9) of the Tax Code, which provides benefits to employees of the Company. Florida Gas contributed $0.5 million and $1.2 million to the VEBA Trust for the years ended December 31, 2007 and 2006, respectively. Upon settlement of the Trust, the anticipated distribution of assets to Florida Gas from the Trust will be contributed to the VEBA Trust.

Prior to 2005, Florida Gas' general policy was to fund accrued post-retirement health care costs as allocated by Enron. As a result of Florida Gas' change in 2005 from a participant in a multi employer plan to a single employer plan, Florida Gas now accounts for its OPEB liability and expense on an actuarial basis, recording its health and life benefit costs over the active service period of employees to the date of full eligibility for the benefits. At December 31, 2005 Florida Gas recognized its OPEB liability by recording a deferred credit of $2.2 million and a corresponding regulatory asset of $2.2 million.

The Company has postretirement health care plans which cover substantially all employees. The health care plans generally provide for cost sharing in the form of retiree contributions, deductibles, and coinsurance between the Company and its retirees, and a fixed cost cap on the amount the Company pays annually to provide future retiree health care coverage under certain of these plans.

The following table summarizes the impact of adopting Statement No. 158 on the Company's postretirement plan reported in the Consolidated Balance Sheet at December 31, 2006:

	Pre-FASB 158	FASB 158 adoption adjustment	Post-FASB 158
		(in thousands)	
Prepaid postretirement benefit cost (non-current) (Note 10)	$ (721)	$ 3,423	$ 2,702
Regulatory asset	1,951	(1,951)	-
Regulatory liability	-	(1,472)	(1,472)

The adoption of Statement No. 158 had no effect on the Consolidated Statements of Income for the years ended December 31, 2007 and December 31, 2006, or for any prior period presented, has not negatively impacted any financial covenants, and is not expected to affect the Company's operating results in future periods.

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Postretirement benefit liabilities are accrued on an actuarial basis during the years an employee provides services. The following table represents a reconciliation of Florida Gas' OPEB plan for the periods indicated:

	Year Ended December 31, 2007	Year Ended December 31, 2006
	(In thousands)	
Change in Benefit Obligation		
Benefit obligation at the beginning of period	$ 5,795	$ 6,665
Service cost	37	46
Interest cost	296	312
Actuarial gain	(320)	(691)
Retiree premiums	415	427
Benefits paid	(1,029)	(964)
CMS Medicare Part D Subsidies Received	108	-
Benefit obligation at end of year	5,302	5,795
Change in Plan Assets		
Fair value of plan assets at the beginning of period	8,497	7,840
Return on plan assets	336	(37)
Employer contributions	380	1,231
Retiree premiums	415	427
Benefits paid	(1,029)	(964)
Fair value of plan assets at end of year (1)	8,599	8,497
Funded Status		
Funded status at the end of the year	$ 3,297	$ 2,702
Amount recognized in the Consolidated Balance Sheets		
Other assets - other (Note 10)	$ 3,297	$ 2,702
Regulatory liability (Note 11)	(3,390)	(1,472)
Net asset (liability) recognized	$ (93)	$ 1,230

(1) Plan assets at December 31, 2007 and 2006 include the amounts of assets expected to be received from the Enron Trust of $6.8 million and $6.5 million, respectively, including a 5 percent annual investment return based on estimate.

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The weighted-average assumptions used to determine Florida Gas' benefit obligations for the periods indicated were as follows:

	Year Ended December 31, 2007	Year Ended December 31, 2006	Year Ended December 31, 2005
Discount rate	6.09%	5.68%	5.50%
Health care cost trend rates	10.00% graded to 5.20% by 2017	11.00% graded to 4.85% by 2013	12.00% graded to 4.65% by 2012

Florida Gas' net periodic (benefit) costs for the periods indicated consisted of the following:

	Year Ended December 31, 2007	Year Ended December 31, 2006	Year Ended December 31, 2005
		(In thousands)	
Service cost	$ 37	$ 46	$ 71
Interest cost	296	312	490
Expected return on plan assets	(414)	(402)	(352)
Recognized actuarial gain	(230)	(223)	(174)
Net periodic (benefit) cost	$ (311)	$ (267)	$ 35

The weighted-average assumptions used to determine Florida Gas' net periodic benefit costs for the periods indicated were as follows:

	Year Ended December 31, 2007	Year Ended December 31, 2006	Year Ended December 31, 2005
Discount rate	5.68%	5.50%	5.75%
Rate of compensation increase	N/A	N/A	N/A
Expected long-term return on plan assets	5.00%	5.00%	5.00%
Health care cost trend rates	11.00% graded to 4.85% by 2013	12.00% graded to 4.65% by 2012	12.00% graded to 4.75% by 2012

Florida Gas employs a building block approach in determining the expected long-term rate on return on plan assets. Historical markets are studied and long-term historical relationships between equities and fixed-income are preserved consistent with the widely accepted capital market principle that assets with higher volatility generate a greater return over the long run. Current market factors such as inflation and interest rates are evaluated before long-term market assumptions are determined. The long-term portfolio return is established via a building block approach with proper consideration of diversification and rebalancing. Peer data and historical returns are reviewed to check for reasonability and appropriateness.

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Assumed health care cost trend rates have a significant effect on the amounts reported for health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	One Percentage Point Increase	One Percentage Point Decrease
	(In thousands)	
Effect on total service and interest cost components	$ 15	$ (13)
Effect on postretirement benefit obligation	$ 240	$ (215)

Discount Rate Selection - The discount rate for each measurement date has been determined consistent with the discount rate selection guidance in Statement No. 106 (as amended by Statement No. 158) using the Citigroup Pension Discount Curve as published on the Society of Actuaries website as the hypothetical portfolio of high-quality debt instruments that would provide the necessary cash flows to pay the benefits when due.

Plan Asset Information - The plan assets shall be invested in accordance with sound investment practices that emphasize long-term investment fundamentals. An investment objective of income and growth for the plan has been adopted. This investment objective: (i) is a risk-averse balanced approach that emphasizes a stable and substantial source of current income and some capital appreciation over the long-term; (ii) implies a willingness to risk some declines in value over the short-term, so long as the plan is positioned to generate current income and exhibits some capital appreciation; (iii) is expected to earn long-term returns sufficient to keep pace with the rate of inflation over most market cycles (net of spending and investment and administrative expenses), but may lag inflation in some environments; (iv) diversifies the plan in order to provide opportunities for long-term growth and to reduce the potential for large losses that could occur from holding concentrated positions; and (iv) recognizes that investment results over the long-term may lag those of a typical balanced portfolio since a typical balanced portfolio tends to be more aggressively invested. Nevertheless, this plan is expected to earn a long-term return that compares favorably to appropriate market indices.

It is expected that these objectives can be obtained through a well-diversified portfolio structure in a manner consistent with the investment policy.

Florida Gas' OPEB weighted-average asset allocation by asset category for the $1.8 million and $2.0 million of assets actually in the VEBA Trust at December 31, 2007 and 2006, respectively, were approximately as follows:

	December 31, 2007	December 31, 2006
Equity securities	31%	0%
Debt securities	69%	0%
Cash and cash equivalents	0%	100%
Total	100%	100%

Based on the postretirement plan objectives, asset allocations should be maintained as follows: equity of 25 percent to 35 percent, fixed income of 65 percent to 75 percent, and cash and cash equivalents of 0 percent to 10 percent.

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The above referenced asset allocations for postretirement benefits are based upon guidelines established by Florida Gas' Investment Policy and is monitored by the Investment Committee of the board of directors in conjunction with an external investment advisor.

Florida Gas expects to contribute approximately $1.1 million to its post-retirement benefit plan in 2008 and approximately $1.1 million annually thereafter until modified by rate case proceedings.

The estimated employer portion of benefit payments, which reflect expected future service, as appropriate, that are projected to be paid are as follows:

Years	Expected Benefits Before Effect of Medicare Part D	Payments Medicare Part D	Net
		(In thousands)	
2008	$ 551	$ 96	$ 455
2009	594	99	495
2010	614	101	513
2011	625	101	524
2012	624	100	524
2013 - 2017	2,935	454	2,481

The Medicare Prescription Drug Act was signed into law December 8, 2003. The Act introduces a prescription drug benefit under Medicare (*Medicare Part D*) as well as a federal subsidy, which is not taxable, to sponsors of retiree healthcare benefit plans that provide a prescription drug benefit that is at least actuarially equivalent to Medicare Part D.

(6) Major Customers and Concentration of Credit Risk

Revenues from individual third party and affiliate customers exceeding 10 percent of total revenues for the periods indicated were approximately as listed below, and in total represented 56%, 58% and 54% of total revenue, respectively.

	Year Ended December 31, 2007	Year Ended December 31, 2006	Year Ended December 31, 2005
		(In thousands)	
Florida Power & Light Company	$ 195,622	$ 200,592	$ 181,486
TECO Energy, Inc.	80,815	80,192	76,059

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The Company had the following transportation receivables from these customers at the dates indicated:

	December 31, 2007	December 31, 2006
	(In thousands)	
Florida Power & Light Company	$ 15,130	$ 15,065
TECO Energy, Inc.	6,201	6,161

The Company has a concentration of customers in the electric and gas utility industries. These concentrations of customers may impact the Company's overall exposure to credit risk, either positively or negatively, in that the customers may be similarly affected by changes in economic or other conditions. Credit losses incurred on receivables in these industries compare favorably to losses experienced in the Company's receivable portfolio as a whole. The Company also has a concentration of customers located in the southeastern United States, primarily within the state of Florida. Receivables are generally not collateralized. From time to time, specifically identified customers having perceived credit risk are required to provide prepayments, deposits, or other forms of security to the Company. Florida Gas sought additional assurances from customers due to credit concerns, and had customer deposits totaling $1.6 million and $1.6 million, and prepayments of $43,000 and $0.2 million at December 31, 2007 and 2006, respectively. The Company's management believes that the portfolio of Florida Gas' receivables, which includes regulated electric utilities, regulated local distribution companies, and municipalities, is of minimal credit risk.

(7) Related Party Transactions

In December 2001 Enron and certain of its subsidiaries filed voluntary petitions for Chapter 11 reorganization with the U.S. Bankruptcy court. At December 31, 2004 Florida Gas and Trading had aggregate outstanding claims with the Bankruptcy Court against Enron and affiliated bankrupt companies of $220.6 million. Of these claims, Florida Gas and Trading filed claims totaling $68.1 and $152.5 million, respectively. Florida Gas and Trading claims pertaining to contracts rejected by ENA were $21.4 and $152.3 million, respectively. In March 2005, ENA filed objections to Trading's claim. In September 2006 the judge issued an order rejecting certain of Trading's arguments and ruling that a contract under which ENA had an in the money position against Trading may be offset against a related contract under which Trading had an in the money position against ENA. The result of the order was a reduction in the allowable amount of Trading's initial claim to $22.7 million. The parties reached a settlement which was approved by the Bankruptcy Court in March 2007 (See Note 14).

Florida Gas' claims against ENA on transportation contracts were reduced by approximately $21.2 million when a third party took assignment of ENA's transportation contracts. In 2004 Florida Gas settled the amount of all of its claims against Enron and a subsidiary debtor. Total allowed claims (including debtor set-offs) were $13.3 million. After approval of the settlement by the Bankruptcy Court, in June 2005 Florida Gas sold its claims, received $3.4 million and recorded Other Income of $0.9 million.

Florida Gas had a construction reimbursement agreement with ENA under which amounts owed to Florida Gas were delinquent. These obligations totaled approximately $7.4 million and were included in Florida Gas' filed bankruptcy claims. These receivables were fully reserved by Florida Gas prior to 2003. Under the Settlement filed by Florida Gas on August 13, 2004 and approved by the FERC on December 21, 2004 Florida Gas will recover the under-recovery on this obligation by rolling in the costs of the facilities constructed, less the recovery from ENA, in its tariff rates (see Note 8). As part of the June 2005 sale of its claims, Florida Gas received $2.1 million for this part of the claim.

The Company provided natural gas sales and transportation services to El Paso affiliates at rates equal to rates charged to non-affiliated customers in the same class of service. Revenues related to these transportation services were approximately nil, $1.0 million and $4.5 million in the years ended December 31, 2007, 2006 and 2005, respectively. The Company's gas sales were immaterial in the years ended December 31, 2007, 2006 and 2005. Florida Gas also purchased transportation services from Southern in connection with its Phase III

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Expansion completed in early 1995. Florida Gas contracted for firm capacity of 100,000 Mcf/day on Southern's system for a primary term of 10 years, to be continued for successive terms of one year each year thereafter unless cancelled by either party, by giving 180 days notice to the other party prior to the end of the primary term or any yearly extension thereof. The amount expensed for these services totaled $6.8 million, $6.6 million and $6.3 million in the years ended December 31, 2007, 2006 and 2005, respectively.

Effective April 1, 2004 services previously provided by bankrupt Enron affiliates to the Company pursuant to the allocation methodology ordered by the Bankruptcy Court were covered and charged under the terms of the Transition Services Agreement / Transition Supplemental Services Agreement (TSA/TSSA). This agreement between Enron and CrossCountry was administered by CrossCountry Energy Services, LLC (CCES), a subsidiary of CCE Holdings, which allocated to the Company its share of total costs. Effective November 17, 2004 an Amended TSA/TSSA agreement was put into effect. This agreement expired on July 31, 2005. The total costs are not materially different from those previously charged. The amount expensed for the seven month-period ended July 31, 2005 was approximately $1.5 million.

On November 5, 2004, CCE Holdings entered into an Administrative Services Agreement (*ASA*) with SU Pipeline Management LP (Manager), a Delaware limited partnership and a wholly-owned subsidiary of Southern Union. Pursuant to the ASA, Manager was responsible for the operations and administrative functions of the enterprise, CCE Holdings and Manager shared certain operations of Manager and its affiliates, and CCE Holdings was obligated to bear its share of costs of Manager and its affiliates. Costs are allocated by Manager and its affiliates to the operating subsidiaries and investees, based on relevant criteria, including time spent, miles of pipe, total assets, labor allocations, or other appropriate methods. Manager provided services to CCE Holdings from November 17, 2004 to December 1, 2006. Following the closing of the Redemption Agreement on December 1, 2006, services continue to be provided by Southern Union affiliates to Florida Gas, and costs allocated using allocation methods consistent with past practices.

The Company has related party activities for operational and administrative services performed by CCES, Panhandle Eastern Pipe Line Company, LP (PEPL), an indirect wholly-owned subsidiary of Southern Union, and other related parties, on behalf of the Company, and corporate service charges from Southern Union. Expenses are generally charged based on either actual usage of services or allocated based on estimates of time spent working for the benefit of the various affiliated companies. Amounts expensed by the Company were $21.5 million, $20.6 million and $20.2 million in the years ended December 31, 2007, 2006 and 2005, respectively, and included corporate service charges from Southern Union of $5.9 million, $4.0 million and $1.6 million in the years ended December 31, 2007, 2006 and 2005, respectively. Additionally, the Company receives allocated costs of certain shared business applications from PEPL and Southern Union. At December 31, 2007 and 2006, the Company had current accounts payable to affiliated companies of $8.4 million and $2.8 million, respectively, relating to these services.

In 2005, the Company paid a subsidiary of CCE Holdings $9.6 million to settle the Cash Balance Plan obligation, which CCE Holdings effectively paid in conjunction with the 2004 acquisition of the Company.

The Company paid cash dividends to its shareholders of $207.1 million, $125.4 million and $121.2 million in the years ended December 31, 2007, 2006, and 2005, respectively. The Company also declared a dividend in December 2007 of $42.6 million, payable in January, 2008 and which was paid on January 18, 2008.

(8) Regulatory Matters

On August 13, 2004 Florida Gas filed a Stipulation and Agreement of Settlement ("Rate Case Settlement") in its Section 4 rate proceeding in Docket No. RP04-12, which established settlement rates and resolved all issues. The settlement rates were approved and became effective on April 1, 2004 for all Florida Gas services and again on April 1, 2005 for Rate Schedule FTS-2 when the basis for rates on Florida Gas incremental facilities changed from a levelized cost of service to a traditional cost of service.

On December 15, 2003 the U.S. Department of Transportation issued a Final Rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the regulation defines as "high consequence areas" ("HCA"). This rule resulted from the enactment of the Pipeline Safety Improvement Act of 2002. The rule

CITRUS CORP. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

requires operators to identify HCAs along their pipelines by December 2004 and to have begun baseline integrity assessments, comprised of in-line inspection (smart pigging), hydrostatic testing, or direct assessment, by June 2004. Operators were required to rank the risk of their pipeline segments containing HCAs and to complete assessments on at least 50 percent of the segments using one or more of these methods by December 2007. Assessments will generally be conducted on the higher risk segments first with the balance being completed by December 2012. As of December 31, 2007, Florida Gas completed 62 percent of the risk assessments. In addition, some system modifications will be necessary to accommodate the in-line inspections. All systems operated by the Company will be compliant with the rule; however, while identification and location of all the HCAs has been completed, it is impossible to determine with certainty the total scope of required remediation activities prior to completion of the assessments and inspections. The required modifications and inspections are currently estimated to be in the range of approximately $21 million to $28 million per year through 2012. Pursuant to the August 13, 2004 Rate Case Settlement, Florida Gas has the right to make limited sections 4 filings to recover, via a surcharge during the settlement's term, depreciation and return on up to approximately $40 million of such costs, as well as security, and Florida Turnpike relocation and modification costs. A reservation surcharge of $0.02 per MMBtu has been in effect since April 1, 2007, subject to refund and further review by the FERC.

In June 2005 FERC issued an order Docket No. AI05-1-000 that expands on the accounting guidance in the proposed accounting release issued in November 2004 on mandated pipeline integrity programs. The order interprets the FERC's existing accounting rules and standardizes classifications of expenditures made by pipelines in connection with an integrity management program. The order is effective for integrity management expenditures incurred on or after January 1, 2006. Florida Gas capitalizes all pipeline assessment costs pursuant to its August 13, 2004 Rate Case Settlement. The Rate Case Settlement contained no reference to the FERC Docket No. AI05-1-000 regarding pipeline assessment costs and provided that the final FERC order approving the Rate Case Settlement constituted final approval of all necessary authorizations to effectuate its provisions. The Rate Case Settlement provisions became effective on March 1, 2005 and new tariff sheets to implement these provisions were filed on March 15, 2005. FERC issued an order accepting the tariff sheets on May 20, 2005. In the years ended December 31, 2007 and 2006, Florida Gas completed and capitalized $9.5 million and $6.7 million, respectively on pipeline assessment projects, as part of the integrity programs.

On October 5, 2005 Florida Gas filed an application with FERC for the Company's proposed Phase VII expansion project. The project will expand Florida Gas' existing pipeline infrastructure in Florida and provide the growing Florida energy market access to additional natural gas supply from the Southern LNG Elba Island liquefied natural gas import terminal near Savannah, Georgia. The Phase VII project calls for Florida Gas to build approximately 17 miles of 36-inch diameter pipeline looping in several segments along an existing right of way and install 9,800 horsepower of compression in a first phase with the possibility of a future second phase. The expansion as currently planned will provide about 100 million cubic feet per day (MMcf/d) of additional capacity to transport natural gas from a connection with Southern Natural Gas Company's Cypress Pipeline project in Clay County, Florida. The FERC issued an order approving the project on June 15, 2006 and construction commenced on November 6, 2006. The first phase was partially placed in service in May 2007 while certain modifications at compressor station 26 are expected to be in service by the end of March, 2008. The updated estimated cost of the expansion is approximately $62 million, including AFUDC. Approximately $12.6 million and $39.3 million is recorded in the line item Construction work in progress at December 31, 2007 and December 31, 2006, respectively.

On October 20, 2005, Florida Gas filed an application with FERC for the Company's State Road 91 Relocation Project. The proposed project will consist of the abandonment of approximately 11.15 miles of 18-inch diameter pipeline and 10.75 miles of 24-inch diameter pipeline in Broward, County Florida. The replacement pipeline will consist of approximately 11.15 miles of 36-inch diameter pipeline. The abandonment and replacement is being performed to accommodate the widening of State Road 91 by the Florida Department of Transportation/Florida Turnpike Enterprise (FDOT/FTE). The estimated cost of the pipeline relocation project is estimated at $110 million, including AFUDC, and Florida Gas is seeking recovery of the construction costs from the FDOT/FTE. The FERC issued an order approving the project on May 3, 2006. Florida Gas notified the FERC that construction commenced on April 25, 2007.

Florida Gas plans to seek FERC approval to construct an expansion to increase its natural gas capacity into Florida by approximately 800 MMcf/d (*Phase VIII Expansion*). The Phase VIII Expansion includes

CITRUS CORP. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

construction of approximately 500 miles of additional large diameter pipeline and the installation of approximately 170,000 horsepower of additional compression. Pending FERC approval, which is expected in 2009, Florida Gas anticipates an in-service date of 2011, at an approximate cost of $2 billion. Florida Gas has signed a 25-year agreement with Florida Power and Light Company, (*FPL*), a wholly-owned subsidiary of FPL Group, Inc., for 400 MMcf/d of capacity.

(9) Property, Plant and Equipment

The principal components of the Company's property, plant and equipment at the dates indicated were as follows:

	December 31, 2007	December 31, 2006
	(In thousands)	
Transmission plant	$ 2,970,560	$ 2,859,920
General plant	28,540	24,970
Intangibles	31,196	25,726
Construction work-in-progress	133,824	85,746
Acquisition adjustment	1,252,466	1,252,466
	4,416,586	4,248,828
Less: Accumulated depreciation and amortization	(1,401,638)	(1,304,133)
Property, Plant and Equipment, net	$ 3,014,948	$ 2,944,695

(10) Other Assets

The principal components of the Company's regulatory assets at the dates indicated were as follows:

	December 31, 2007	December 31, 2006
	(In thousands)	
Ramp-up assets, net (1)	$ 11,616	$ 11,928
Fuel Tracker	2,295	11,747
Cash balance plan settlement (Note 5)	2,326	4,185
Environmental non-PCB clean-up cost (Note 12)	1,147	1,000
Other miscellaneous	1,823	2,147
Total Regulatory Assets	$ 19,207	$ 31,007

(1) Ramp-up assets are regulatory assets which Florida Gas was specifically allowed to establish in the FERC certificates authorizing the Phase IV and V Expansion projects.

CITRUS CORP. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The principal components of the Company's other assets at the dates indicated were as follows:

	December 31, 2007	December 31, 2006
	(In thousands)	
Long-term receivables (Note 14)	$ 2,859	$ 71,648
Other post employment benefits (Note 5)	3,297	2,702
Preliminary survey & investigation	3,021	996
FERC ACA fee	1,061	839
Other miscellaneous	600	244
Total Other Assets - other	$ 10,838	$ 76,429

(11) Deferred Credits

The principal components of the Company's regulatory liabilities at the dates indicated were as follows:

	December 31, 2007	December 31, 2006
	(In thousands)	
Balancing tools (1)	$ 11,413	$ 12,154
Other post employment benefits (Note 5)	3,390	1,472
Other miscellaneous	39	630
Total Regulatory liabilities	$ 14,842	$ 14,256

(1) Balancing tools are a regulatory method by which Florida Gas recovers the costs of operational balancing of the pipeline's system. The balance can be a deferred charge or credit, depending on timing, rate changes and operational activities.

The principal components of the Company's other deferred credits at the dates indicated were as follows:

	December 31, 2007	December 31, 2006
	(In thousands)	
Post construction mitigation costs	$ 1,686	$ 2,073
Deferred compensation	889	1,090
Environmental non-PCB clean-up cost reserve (Note 12)	1,337	1,423
Taxes Payable	3,116	1,664
Asset retirement obligation (Note 2)	471	481
Other miscellaneous	1,703	1,398
Total Deferred Credits - other	$ 9,202	$ 8,129

CITRUS CORP. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(12) Environmental Reserve

The Company is subject to extensive federal, state and local environmental laws and regulations. These laws and regulations require expenditures in connection with the construction of new facilities, the operation of existing facilities and for remediation at various operating sites. The implementation of the Clean Air Act Amendments resulted in increased operating expenses. These increased operating expenses did not have a material impact on the Company's consolidated financial statements.

Florida Gas conducts assessment, remediation, and ongoing monitoring of soil and groundwater impact which resulted from its past waste management practices at its Rio Paisano and Station 11 facilities. The anticipated costs over the next five years are: 2008 - $0.3 million, 2009 - $0.1 million, 2010 - $0.2 million, 2011 - $0.3 million and 2012 – $0.1 million. The expenditures thereafter are estimated to be $0.6 million for soil and groundwater remediation. The liability is recognized in other current liabilities and in other deferred credits and in total amounted to $1.6 million and $1.6 million at December 31, 2007 and 2006, respectively. Costs of $0.2 million, $0.1 million and $0.8 million were expensed during the years ended December 31, 2007, 2006 and 2005, respectively. Florida Gas recorded the estimated costs of remediation to be spent after April 1, 2010 of $1.1 million and $1.0 million at December 31, 2007 and 2006, respectively (Note 10), as a regulatory asset based on the probability of recovery in rates in its next rate case.

Prior to December 31, 2005, no such liability was recognized since it was previously estimated to be less than $1.0 million, and therefore, considered not to be material. Amounts incurred for environmental assessment and remediation were expensed as incurred.

(13) Accumulated Other Comprehensive Loss

Deferred gains and losses in connection with the termination of the following derivative instruments which were previously accounted for as cash flow hedges form part of other comprehensive income. Such amounts are being amortized over the terms of the hedged debt.

The table below provides an overview of comprehensive income for the periods indicated:

	Year Ended December 31, 2007	Year Ended December 31, 2006	Year Ended December 31, 2005
		(In thousands)	
Interest rate swap loss on 7.625% $325 million note due 2010	$ 1,873	$ 1,872	$ 1,872
Interest rate swap loss on 7.0% $250 million note due 2012	1,228	1,228	1,228
Interest rate swap gain on 9.19% $150 million note due 2005-2024	(462)	(462)	(462)
Total	$ 2,639	$ 2,638	$ 2,638

CITRUS CORP. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The table below provides an overview of the components in accumulated other comprehensive loss at the dates indicated:

	Termination Date	Amortization Period	Original Gain/(Loss)	December 31, 2007	December 31, 2006
				(In thousands)	
Interest rate swap loss on 7.625% $325 million note due 2010	December 2000	10 years	$ (18,724)	$ (5,461)	$ (7,334)
Interest rate swap loss on 7.0% $250 million note due 2012	July 2002	10 years	(12,280)	(5,579)	(6,807)
Interest rate swap gain on 9.19% $150 million note due 2005-2024	November 1994	20 years	9,236	3,155	3,617
Total				$ (7,885)	$ (10,524)

(14) Commitments and Contingencies

From time to time, in the normal course of business, the Company is involved in litigation, claims or assessments that may result in future economic detriment. Where appropriate, Citrus has made accruals in accordance with *FASB Statement No. 5, Accounting for Contingencies,* in order to provide for such matters. Management believes the final disposition of these matters will not have a material adverse effect on the Company's' results of operations or financial position.

Florida Gas plans to seek FERC approval to construct an expansion to increase its natural gas capacity into Florida by approximately 800 MMcf/d. The Phase VIII Expansion includes construction of approximately 500 miles of additional large diameter pipeline and the installation of approximately 170,000 horsepower of additional compression. Pending FERC approval, which is expected in 2009, Florida Gas anticipates an in-service date of 2011, at an approximate cost of $2 billion. Florida Gas has signed a 25-year agreement with FPL for 400 MMcf/d of capacity.

On February 5, 2008, Citrus entered into a $500 million unsecured construction and term loan agreement (*Citrus Credit Agreement*) with a wholly owned subsidiary of FPL Group Capital Inc., which is a wholly-owned subsidiary of FPL Group, Inc. Citrus will contribute the proceeds of this loan to Florida Gas in order to finance a portion of the Phase VIII Expansion. The Citrus Credit Agreement provides for a single $500 million draw after Florida Gas' receipt of a certificate from the FERC authorizing construction of the Phase VIII Expansion and Citrus' satisfaction of customary conditions precedent. On or before the Phase VIII Expansion in-service date, the construction loan will convert to an amortizing 20-year term loan with a $300 million balloon payment at maturity. The loan requires semi-annual payments of principal beginning five years and six months after the conversion to a term loan. The Citrus Credit Agreement provides for interest on the outstanding principal amount at the rate of six-month LIBOR plus 535 basis points prior to conversion to a term loan and at the twenty-year treasury rate plus 535 basis points after conversion to a term loan. The loan is not guaranteed by Florida Gas and does not include a prepayment option. The Citrus Credit Agreement contains certain customary representations, warranties and covenants and requires the execution of a negative pledge agreement by Florida Gas.

The Florida Department of Transportation, Florida's Turnpike Enterprise (*FDOT/FTE*) has various turnpike widening projects that have or may, over time, impact one or more of Florida Gas' mainline pipelines co-located in FDOT/FTE rights-of-way. The first phase of the turnpike project includes replacement of approximately 11.3 miles of its existing 18- and 24-inch pipelines located in FDOT/FTE right-of-way in Florida. The estimated cost of such replacement is approximately $110 million, including AFUDC. Florida Gas is also in discussions with the FDOT/FTE related to additional projects that may affect Florida Gas' 18- and 24-inch pipelines within FDOT/FTE right-of-way. The total miles of pipe that may ultimately be affected by all of the FDOT/FTE widening projects, and any associated relocation and/or right-of-way costs, cannot be determined at this time.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Under certain conditions, existing agreements between Florida Gas and the FDOT/FTE require the FDOT/FTE to provide any new right-of-way needed for relocation of the pipelines and for Florida Gas to pay for rearrangement or relocation costs. Under certain other conditions, Florida Gas may be entitled to reimbursement for the costs associated with relocation, including construction and right-of-way costs. On January 25, 2007, Florida Gas filed a complaint against FDOT/FTE in the Seventeenth Judicial Circuit, Broward County, Florida, to seek relief for three specific sets of FDOT widening projects in Broward County. The complaint seeks damages for breach of easement and relocation agreements for the one set of projects on which construction has already commenced, and injunctive relief as well as damages for the two other sets of projects upon which construction has yet to commence. On April 24, 2007 the FDOT/FTE filed a complaint against Florida Gas in the Ninth Judicial Circuit, Orange County, Florida, to seek a declaratory judgment that under the existing agreements Florida Gas is liable for the costs of relocation associated with such projects and is not entitled to certain other rights. On August 7, 2007 the Orange County Court granted a motion by Florida Gas to abate and stay the Orange County action. The FDOT/FTE filed an amended answer and counterclaim against Florida Gas on February 8, 2008 in the Broward County action. The counterclaim alleges Florida Gas is subject to estoppel and breach of contract regarding removal from service of the existing pipelines on the project currently under construction and seeks a declaratory judgment that Florida Gas is responsible for all relocation costs and is not entitled to workspace and uniform minimum area precluding FDOT/FTE activity. On February 14, 2008 the case was transferred to the Broward County Complex Business Civil Division 07. As a result, the March 10, 2008 hearing on the motion by Florida Gas for a temporary injunction enjoining the FDOT/FTE interference with the pipelines of Florida Gas will be rescheduled.

On October 24, 2007, Florida Gas filed a complaint in the US District Court of the Northern District of Florida, Tallahassee Division, against Stephanie C. Kopelousos (*Kopelousos*) in her official capacity as the Secretary of the Florida Department of Transportation, seeking to enjoin Kopelousos from violating federal law in connection with construction of the FDOT/FTE Golden Glades project, a new toll plaza in Miami-Dade County, Florida. Florida Gas seeks a declaratory judgment that certain Florida statutes are preempted by federal law to the extent such state statutes purport to regulate the abandonment or relocation schedule for the federally regulated pipelines of Florida Gas and prospective preliminary and permanent injunctive relief enjoining Kopelousos from proceeding with construction on the Golden Glades project over and around such pipelines. Kopelousos has filed a motion to dismiss the complaint and Florida Gas has responded. Based upon representations by the FDOT/FTE that the Golden Glades project has been moved to 2013, the parties entered into a joint stipulation of dismissal without prejudice on February 15, 2008.

Should Florida Gas be denied reimbursement by the FDOT/FTE for any possible relocation expenses, such costs are expected to be covered by operating cash flows and additional borrowings. Florida Gas expects to seek rate recovery at FERC for all reasonable and prudent costs incurred in relocating its pipelines to accommodate the FDOT/FTE to the extent not reimbursed by the FDOT/FTE. There can be no assurance that Florida Gas will be successful in obtaining complete reimbursement for any such relocation costs from the FDOT/FTE or from its customers or that the timing of reimbursement will fully compensate Florida Gas for its costs.

Florida Gas and Trading previously filed bankruptcy-related claims against Enron and other affiliated bankrupt companies totaling $220.6 million. Of these claims, Florida Gas and Trading filed claims totaling $68.1 and $152.5 million, respectively. Florida Gas and Enron agreed on the amount of the claim at $13.3 million, and Florida Gas assigned its claims to a third party and received $3.4 million in June 2005. Trading's claim was for rejection damages on two physical/financial swaps and a gas sales contract, as well as certain delinquent amounts owed pre-petition. In March 2005, Enron North America Corp. (ENA) filed objections to Trading's claim. In September 2006 the judge issued an order which rejected certain of Trading's arguments and ruled that a contract under which ENA had an in the money position against Trading could be offset against a related contract under which Trading had an in the money position against ENA. The result of the order was a reduction in the allowable amount of Trading's initial claim to $22.7 million. The parties reached a settlement on the amount of the allowed claim which was approved by the bankruptcy court in March 2007. Citrus fully reserved for the amounts in 2001 and sold the receivable claim in the second quarter of 2007 to a third party for a pre-tax gain on $11.4 million. The gain has been reported in *Other, net* in the accompanying Consolidated Statements of Income, which is consistent with the presentation of the original write-off recorded in 2001.

CITRUS CORP. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

On March 7, 2003, Trading filed an action, requesting the court to declare that Duke Energy LNG Sales, Inc. (Duke) breached a natural gas trading contract by failing to provide sufficient volumes of gas to Trading. Duke sent Trading a notice of termination of the contract and answered and filed a counterclaim, arguing that Trading failed to timely increase the amount of a letter of credit that was required of Trading under the contract, and that Trading had breached a "resale restriction" on the gas. On June 2, 2003, Trading notified Duke that, because Duke had defaulted on the contract and failed to cure, Trading was terminating the contract effective as of June 5, 2003. On August 8, 2003, Trading sent its final "termination payment" invoice to Duke in the amount of $187 million, and recorded a receivable of $75 million (subsequently reduced by $6.5 million to $68.5 million, reflected in *Other Assets* at December 31, 2006, to provide for a related settlement, see below). After denying motions for summary judgment by both parties, the judge ordered the parties to attempt to narrow the scope of the issues to be tried. Pre-trial conferences were held in January 2007, a jury was selected and opening arguments were scheduled. Following the judge's rulings on certain matters, on January 29, 2007, Trading, Citrus, Southern Union and El Paso (collectively, Citrus Parties) entered into a settlement regarding litigation with Spectra Energy LNG Sales, Inc., formerly known as Duke Energy LNG Sales, Inc. (Duke), and its parent company Spectra Energy Corporation (collectively, Spectra), whereby Spectra agreed to pay $100 million to Trading, which was received on January 30, 2007. Citrus recorded a pre-tax gain of $24 million in the first quarter of 2007. This gain has been reported in *Other, net* in the accompanying Consolidated Statements of Income, which is consistent with the historical results of Trading's activities.

In June 2004 the Company recorded an accrual for a contingent obligation of up to $6.5 million to terminate a gas sales contract with a third party. The contingent obligation was extinguished with a payment to the third party on February 6, 2007 of $6.5 million from proceeds resulting from the settlement of the Duke litigation.

Jack Grynberg, an individual, filed actions for damages against a number of companies, including Florida Gas and Citrus, now transferred to the U.S. District Court for the District of Wyoming, alleging mismeasurement of gas volumes and Btu content, resulting in lower royalties to mineral interest owners. On October 20, 2006, the District Judge adopted in part the earlier recommendation of the Special Master in the case and ordered the dismissal of the case against the defendants. Grynberg is appealing that action to the Tenth Circuit Court of Appeals. Grynberg's opening brief was filed on July 31, 2007. Respondents filed their brief rebutting Grynberg's arguments on November 21, 2007. Florida Gas believes that its measurement practices conformed to the terms of its FERC gas tariffs, which were filed with and approved by FERC. As a result, Florida Gas believes that it has meritorious defenses to these lawsuits (including FERC-related affirmative defenses, such as the filed rate/tariff doctrine, the primary/exclusive jurisdiction of FERC, and the defense that Florida Gas complied with the terms of its tariffs) and will continue to vigorously defend against them, including any appeal from the dismissal of the Grynberg case. The Company does not believe the outcome of this case will have a material adverse effect on its financial position, results of operations or cash flows.

TCLP 10-Q 9/30/2008

Section 1: 10-Q (FORM 10Q)

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended September 30, 2008

or

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Transition period from _________ to _________

Commission File Number: 000-26091
TC PipeLines, LP
(Exact name of registrant as specified in its charter)

Delaware	52-2135448
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)
13710 FNB Parkway Omaha, Nebraska	68154-5200
(Address of principal executive offices)	(Zip code)

877-290-2772
(Registrant's telephone number, including area code)

Indicate by check mark if the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes [X] No [ ]

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definitions of “large accelerated filer”, “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act.
Large accelerated filer [X] Accelerated filer [ ]
Non-accelerated filer [ ] (Do not check if a smaller reporting company) Smaller reporting company [ ]

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes [ ] No [X]

As of November 3, 2008, there were 34,856,086 of the registrant’s common units outstanding.

TC PIPELINES, LP

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All amounts are stated in United States dollars unless otherwise indicated.

Glossary

The abbreviations, acronyms, and industry terminology used in this quarterly report are defined as follows:

ANR	ANR Pipeline Company
Bcf/d	Billion cubic feet per day
Bison Project	Bison Pipeline Project
Chicago IV	Northern Border's proposed expansion project
Collar Agreement	Northern Border's zero cost interest rate collar agreement
DCF	Discounted cash flow
Dth/d	Dekatherms per day
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GAAP	U.S. generally accepted accounting principles
GLGT	Great Lakes Gas Transmission Limited Partnership
Great Lakes	Great Lakes Gas Transmission Limited Partnership
INGAA	Interstate Natural Gas Association of America
LIBOR	London Interbank Offered Rate
MLP	Master Limited Partnership
MMcf/d	Million cubic feet per day
NBPC	Northern Border Pipeline Company
Northern Border	Northern Border Pipeline Company
Our pipeline systems	Great Lakes, Northern Border and Tuscarora
Partnership	TC PipeLines, LP and its subsidiaries
Pathfinder Project	Pathfinder Pipeline Project
REX East	Eastern segment of the Rockies Express Pipeline
REX West	Western segment of the Rockies Express Pipeline
ROE	Return on equity
ROFR	Right of first refusal
SEC	Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards
TC Pipelines	TC PipeLines, LP and its subsidiaries
TCNB	TransCanada Northern Border Inc.
TGTC	Tuscarora Gas Transmission Company
TransCanada	TransCanada Corporation and its subsidiaries
TSA	Transportation Security Administration
Tuscarora	Tuscarora Gas Transmission Company
U.S	United States of America
WCSB	Western Canada Sedimentary Basin

PART I – FINANCIAL INFORMATION

Item 1. Financial Statements

TC PipeLines, LP
Consolidated Statement of Income

(unaudited) *(millions of dollars except per common unit amounts)*	Three months ended September 30, **2008**	2007	Nine months ended September 30, **2008**	2007
Equity income from investment in Great Lakes (Note 2)	**12.0**	14.2	**44.4**	34.3
Equity income from investment in Northern Border (Note 3)	**19.9**	16.2	**48.1**	44.3
Transmission revenues	**8.2**	6.7	**23.3**	20.3
Operating expenses	**(2.3)**	(2.2)	**(6.8)**	(6.4)
Depreciation	**(1.8)**	(1.6)	**(5.1)**	(4.7)
Financial charges, net and other	**(7.7)**	(8.7)	**(22.8)**	(25.5)
Net income	**28.3**	24.6	**81.1**	62.3
Net income allocation				
Common units	**25.1**	22.4	**72.5**	57.0
General partner	**3.2**	2.2	**8.6**	5.3
	28.3	24.6	**81.1**	62.3
Net income per common unit (Note 6)	**$ 0.72**	$ 0.64	**$ 2.08**	$ 1.81
Weighted average common units outstanding *(millions)*	**34.9**	34.9	**34.9**	31.5
Common units outstanding, end of the period *(millions)*	**34.9**	34.9	**34.9**	34.9

Consolidated Statement of Comprehensive Income

(unaudited) *(millions of dollars)*	Three months ended September 30, **2008**	2007	Nine months ended September 30, **2008**	2007
Net income	**28.3**	24.6	**81.1**	62.3
Other comprehensive loss				
Change associated with hedging transactions (Note 9)	**(1.3)**	(7.0)	**(1.7)**	(2.3)
Change associated with hedging transactions of investees	-	(0.5)	**(0.7)**	(0.9)
	(1.3)	(7.5)	**(2.4)**	(3.2)
Total comprehensive income	**27.0**	17.1	**78.7**	59.1

See accompanying notes to the consolidated financial statements.

TC PipeLines, LP
Consolidated Balance Sheet

(unaudited)

(millions of dollars)	**September 30, 2008**	December 31, 2007
ASSETS		
Current Assets		
Cash and short-term investments	**11.0**	7.5
Accounts receivable and other	**3.7**	4.2
	14.7	11.7
Investment in Great Lakes (Note 2)	**710.5**	721.1
Investment in Northern Border (Note 3)	**517.2**	541.9
Plant, property and equipment (net of $66.8 accumulated depreciation, 2007 - $61.7)	**135.6**	134.1
Goodwill	**81.7**	81.7
Other assets	**1.6**	2.1
	1,461.3	1,492.6
LIABILITIES AND PARTNERS' EQUITY		
Current Liabilities		
Bank indebtedness	**-**	1.4
Accounts payable	**2.2**	4.8
Accrued interest	**3.5**	3.0
Current portion of long-term debt (Note 5)	**4.5**	4.6
Other current liabilities	**0.5**	-
	10.7	13.8
Other long-term liabilities	**11.0**	9.9
Long-term debt (Note 5)	**541.6**	568.8
	563.3	592.5
Partners' Equity		
Common units	**892.6**	892.3
General partner	**19.1**	19.1
Accumulated other comprehensive loss	**(13.7)**	(11.3)
	898.0	900.1
	1,461.3	1,492.6

Subsequent events (Note 12)

See accompanying notes to the consolidated financial statements.

TC PipeLines, LP
Consolidated Statement of Cash Flows

(unaudited) *(millions of dollars)*	**Nine months ended September 30,** **2008**	2007
CASH GENERATED FROM OPERATIONS		
Net income	**81.1**	62.3
Depreciation	**5.1**	4.7
Amortization of other assets	**0.4**	0.3
Non-controlling interests	-	0.2
Increase in long-term liabilities	**0.1**	-
Equity allowance for funds used during construction	**(0.2)**	-
Increase in operating working capital (Note 10)	**(0.2)**	(0.7)
	86.3	66.8
INVESTING ACTIVITIES		
Return of capital from Great Lakes (Note 2)	**10.6**	6.7
Return of capital from Northern Border (Note 3)	**23.9**	18.2
Investment in Great Lakes (Note 2)	-	(733.0)
Investment in Northern Border (Note 3)	-	(7.5)
Capital expenditures	**(6.4)**	(4.4)
Other assets	-	(1.1)
(Increase)/decrease in investing working capital (Note 10)	**(2.8)**	1.2
	25.3	(719.9)
FINANCING ACTIVITIES		
Distributions paid	**(80.8)**	(61.3)
Equity issuances, net	-	607.0
Long-term debt issued	**4.0**	152.5
Long-term debt repaid (Note 5)	**(31.3)**	(34.9)
	(108.1)	663.3
Increase in cash and short-term investments	**3.5**	10.2
Cash and short-term investments, beginning of period	**7.5**	4.6
Cash and short-term investments, end of period	**11.0**	14.8
Interest payments made	**17.9**	23.9

See accompanying notes to the consolidated financial statements.

TC PipeLines, LP
Consolidated Statement of Changes in Partners' Equity

(unaudited)	**Common Units**		**General Partner**	**Accumulated Other Comprehensive Loss** [(1)]	**Partners' Equity**	
	(millions of units)	*(millions of dollars)*	*(millions of dollars)*	*(millions of dollars)*	*(millions of units)*	*(millions of dollars)*
Partners' equity at December 31, 2007	34.9	892.3	19.1	(11.3)	34.9	900.1
Net income	-	72.5	8.6	-	-	81.1
Distributions paid	-	(72.2)	(8.6)	-	-	(80.8)
Other comprehensive loss	-	-	-	(2.4)	-	(2.4)
Partners' equity at September 30, 2008	**34.9**	**892.6**	**19.1**	**(13.7)**	**34.9**	**898.0**

(1) TC PipeLines, LP uses derivatives to assist in managing its exposure to interest rate risk. Based on interest rates at September 30, 2008, the amount of losses related to cash flow hedges reported in accumulated other comprehensive income that will be reclassified to net income in the next 12 months is $3.8 million, which will be offset by a reduction to interest expense of a similar amount.

See accompanying notes to the consolidated financial statements.

TC PipeLines, LP
Notes to Consolidated Financial Statements

Note 1 Organization and Significant Accounting Policies
TC PipeLines, LP and its subsidiaries are collectively referred to herein as “TC PipeLines” or “the Partnership”. In this report, references to “we”, “us” or “our” refer to TC PipeLines or the Partnership.

The preparation of financial statements in conformity with United States of America (U.S.) generally accepted accounting principles (GAAP) requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Although management believes these estimates are reasonable, actual results could differ from these estimates. In the opinion of management, these consolidated financial statements have been properly prepared within reasonable limits of materiality and include all adjustments (consisting of normal recurring accruals) necessary for a fair presentation of the financial results for the interim periods presented.

The results of operations for the three and nine months ended September 30, 2008 and 2007 are not necessarily indicative of the results that may be expected for a full fiscal year. The unaudited interim financial statements should be read in conjunction with the financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2007. Our significant accounting policies are consistent with those disclosed in Note 2 of the financial statements in our annual report on Form 10-K for the year ended December 31, 2007. Certain comparative figures have been reclassified to conform to the current period’s presentation.

Note 2 Investment in Great Lakes
On February 22, 2007, we acquired a 46.45 per cent partner interest in Great Lakes Gas Transmission Limited Partnership (Great Lakes). On the same day, a wholly-owned subsidiary of TransCanada Corporation (TransCanada) acquired 100 per cent ownership of the operator of Great Lakes. Great Lakes is regulated by the Federal Energy Regulatory Commission (FERC).

We use the equity method of accounting for our interest in Great Lakes. Great Lakes had no undistributed earnings for either the nine months ended September 30, 2008 or the period February 23, 2007 to September 30, 2007.

The following tables contain summarized financial information for Great Lakes:

Summarized Consolidated Great Lakes Income Statement *(unaudited)* *(millions of dollars)*	**Three months ended September 30,** **2008**	2007	**Nine months ended September 30,** **2008**	For the period February 23 to September 30, 2007
Transmission revenues	**66.7**	65.6	**213.9**	162.2
Operating expenses	**(17.1)**	(12.6)	**(45.9)**	(34.0)
Depreciation	**(14.7)**	(14.5)	**(43.9)**	(34.9)
Financial charges, net and other	**(8.0)**	(8.1)	**(24.4)**	(19.5)
Michigan business tax	**(1.2)**	-	**(4.2)**	-
Net income	**25.7**	30.4	**95.5**	73.8

Summarized Consolidated Great Lakes Balance Sheet
(unaudited)
(millions of dollars)

	September 30, 2008	December 31, 2007
Assets		
Cash and short-term investments	**1.1**	32.0
Other current assets	**100.6**	55.5
Plant, property and equipment, net	**931.9**	969.2
	1,033.6	1,056.7
Liabilities and Partners' Equity		
Current liabilities	**49.0**	50.7
Deferred credits	**1.7**	0.4
Long-term debt, including current maturities	**440.0**	440.0
Partners' capital	**542.9**	565.6
	1,033.6	1,056.7

Note 3 Investment in Northern Border

We own a 50 per cent general partner interest in Northern Border Pipeline Company (Northern Border). Effective April 1, 2007, TransCanada Northern Border Inc. (TCNB), a wholly-owned subsidiary of TransCanada, became the operator of Northern Border. Northern Border is regulated by the FERC.

We use the equity method of accounting for our interest in Northern Border. Northern Border had no undistributed earnings for the nine months ended September 30, 2008 and 2007.

The following tables contain summarized financial information for Northern Border:

Summarized Northern Border Income Statement
(unaudited)
(millions of dollars)

	Three months ended September 30,		**Nine months ended September 30,**	
	2008	2007	**2008**	2007
Transmission revenues	**67.7**	79.6	**212.8**	228.0
Operating expenses	**(19.3)**	(21.6)	**(57.5)**	(61.7)
Depreciation	**(15.3)**	(15.1)	**(45.8)**	(45.6)
Financial charges, net and other	**7.1**	(10.2)	**(12.1)**	(30.9)
Net income	**40.2**	32.7	**97.4**	89.8

Summarized Northern Border Balance Sheet
(unaudited)
(millions of dollars)

	September 30, 2008	December 31, 2007
Assets		
Cash and short-term investments	**18.6**	22.9
Other current assets	**31.1**	39.8
Plant, property and equipment, net	**1,398.3**	1,428.3
Other assets	**25.5**	23.9
	1,473.5	1,514.9
Liabilities and Partners' Equity		
Current liabilities	**53.0**	53.4
Deferred credits and other	**9.2**	8.1
Long-term debt, including current maturities	**621.4**	615.3
Partners' equity		
Partners' capital	**793.8**	840.5
Accumulated other comprehensive loss	**(3.9)**	(2.4)
	1,473.5	1,514.9

Note 4 Investment in Tuscarora

As of December 31, 2007, we acquired the remaining two per cent general partner interest in Tuscarora Gas Transmission Company (Tuscarora), thereby making it a wholly-owned subsidiary. Tuscarora is operated by TCNB and is regulated by the FERC.

We use the consolidation method of accounting for our ownership of Tuscarora.

The following tables contain summarized financial information for Tuscarora:

Summarized Tuscarora Income Statement *(unaudited)* *(millions of dollars)*	**Three months ended September 30,** **2008**	2007	**Nine months ended September 30,** **2008**	2007
Transmission revenues	**8.2**	6.7	**23.3**	20.3
Operating expenses	**(1.4)**	(1.2)	**(3.7)**	(3.7)
Depreciation	**(1.8)**	(1.6)	**(5.1)**	(4.7)
Financial charges, net and other	**(1.1)**	(1.0)	**(3.1)**	(3.4)
Net income	**3.9**	2.9	**11.4**	8.5

Summarized Tuscarora Balance Sheet *(unaudited)* *(millions of dollars)*	**September 30, 2008**	December 31, 2007
Assets		
Cash and short-term investments	-	6.1
Other current assets	**13.6**	2.6
Plant, property and equipment, net	**135.6**	134.1
Other assets	**0.3**	0.6
	149.5	143.4
Liabilities and Partners' Equity		
Current liabilities	**3.1**	6.1
Long-term debt, including current maturities	**64.1**	66.4
Partners' capital	**82.3**	70.9
	149.5	143.4

Summarized Tuscarora Cash Flow Statement *(unaudited)* *(millions of dollars)*	**Three months ended September 30,** **2008**	2007	**Nine months ended September 30,** **2008**	2007
Cash flows provided by operating activities	**7.2**	4.6	**17.3**	13.5
Cash flows (used in)/provided by investing activities	**(1.3)**	0.6	**(9.2)**	(3.1)
Cash flows used in financing activities	**(5.8)**	-	**(14.2)**	(2.4)
Increase/(decrease) in cash and short-term investments	-	5.2	**(6.1)**	8.0
Cash and short-term investments, beginning of period	-	5.7	**6.1**	2.9
Cash and short-term investments, end of period	-	10.9	-	10.9

Note 5 Credit Facility and Long-Term Debt

(unaudited) *(millions of dollars)*	**September 30, 2008**	December 31, 2007
Senior Credit Facility	**482.0**	507.0
7.13% Series A Senior Notes due 2010	**52.9**	54.5
7.99% Series B Senior Notes due 2010	**5.3**	5.5
6.89% Series C Senior Notes due 2012	**5.9**	6.4
	546.1	573.4

The Senior Credit Facility consists of a $475.0 million senior term loan and a $250.0 million senior revolving credit facility. At September 30, 2008, $7.0 million was outstanding under our senior revolving credit facility, leaving $243.0 million available for future borrowings. The interest rate on the Senior Credit Facility averaged 3.31 per cent for the three months ended September 30, 2008 (2007 – 5.97 per cent), while for the nine months ended September 30, 2008 the interest rate on the Senior Credit Facility averaged 3.93 per cent (2007 – 6.02 per cent). After hedging activity, the interest rate incurred on the Senior Credit Facility averaged 5.23 per cent for the three months ended September 30, 2008 (2007 – 5.70 per cent) and 5.18 per cent for the nine months ended September 30, 2008 (2007 – 5.52 per cent). Prior to hedging activities, the interest rate was 3.36 per cent at September 30, 2008 (December 31, 2007 – 5.62 per cent). At September 30, 2008, we were in compliance with our financial covenants.

Annual maturities are as follows: 2008 - $2.3 million; 2009 - $4.4 million; 2010 - $53.5 million; 2011 - $482.8 million; and, thereafter - $3.1 million.

Note 6 Net Income per Common Unit

Net income per common unit is computed by dividing net income, after deduction of the general partner's allocation, by the weighted average number of common units outstanding. The general partner's allocation is equal to an amount based upon the general partner's two per cent interest, plus an amount equal to incentive distributions. Incentive distributions are received by the general partner if quarterly cash distributions on the common units exceed levels specified in the partnership agreement. Net income per common unit was determined as follows:

(unaudited)	**Three months ended September 30,**		**Nine months ended September 30,**	
(millions of dollars except per unit)	**2008**	2007	**2008**	2007
Net income	**28.3**	24.6	**81.1**	62.3
Net income allocated to general partner				
General partner interest	**(0.6)**	(0.4)	**(1.6)**	(1.2)
Incentive distribution income allocation	**(2.6)**	(1.8)	**(7.0)**	(4.1)
	(3.2)	(2.2)	**(8.6)**	(5.3)
Net income allocable to common units	**25.1**	22.4	**72.5**	57.0
Weighted average common units outstanding *(millions)*	**34.9**	34.9	**34.9**	31.5
Net income per common unit	**$ 0.72**	$ 0.64	**$ 2.08**	$ 1.81

Note 7 Cash Distributions

For the three and nine months ended September 30, 2008, we distributed $0.705 and $2.07 per common unit (2007 – $0.655 and $1.905 per common unit). The distributions for the three and nine months ended September 30, 2008 included incentive distributions to the general partner of $2.6 million and $7.0 million (2007 - $1.8 million and $4.1 million).

Note 8 Related Party Transactions

The Partnership does not have any employees. The management and operating functions are provided by the general partner. The general partner does not receive a management fee in connection with its management of the Partnership. The Partnership reimburses the general partner for all costs of services provided, including the costs of employee, officer and director compensation and benefits, and all other expenses necessary or appropriate to the conduct of the business of, and allocable to, the Partnership. Such costs include (i) overhead costs (such as office space and equipment) and (ii) out-of-pocket expenses related to the provision of such services. The Partnership Agreement provides that the general partner will determine the costs that are allocable to the Partnership in any reasonable manner determined by the general partner in its sole discretion. Total costs charged to the Partnership by the general partner were $0.5 million and $1.6 million for the three and nine months ended September 30, 2008 (2007 - $0.5 million and $1.4 million).

TCNB became the operator of Northern Border effective April 1, 2007. The operator of Great Lakes became a wholly-owned subsidiary of TransCanada through TransCanada's acquisition of Great Lakes Gas Transmission Company on February 22, 2007. TCNB also became the operator of Tuscarora, as part of the December 19, 2006 acquisition of an additional 49 per cent general partner interest in Tuscarora. TransCanada and its affiliates provide capital and operating services to Great Lakes, Northern Border and Tuscarora (together, "our pipeline systems"). TransCanada and its affiliates incur costs on behalf of our pipeline systems, including, but not limited to, employee salary and benefit costs, property and liability insurance costs, and transition costs. Total costs charged to our pipeline systems during the three and nine months ended September 30, 2008 and 2007 by TransCanada and its affiliates and amounts owed to TransCanada and its affiliates at September 30, 2008 and December 31, 2007 are summarized in the following tables:

(unaudited)	**Three months ended September 30,**		**Nine months ended September 30,**	
(millions of dollars)	**2008**	2007	**2008**	2007 [(1)]
Costs charged by TransCanada and its affiliates:				
Great Lakes	**8.2**	5.2	**23.4**	22.2
Northern Border	**7.5**	7.4	**23.5**	14.9
Tuscarora	**0.9**	0.8	**2.9**	1.7
Impact on the Partnership's net income:				
Great Lakes	**3.6**	2.4	**10.1**	10.3
Northern Border	**3.2**	3.7	**9.6**	7.5
Tuscarora	**0.7**	0.8	**2.0**	1.7

[(1)] The amounts disclosed for Great Lakes are for the period February 23 to September 30, 2007. The amounts disclosed for Northern Border are for the period April 1 to September 30, 2007.

(unaudited) *(millions of dollars)*	**September 30, 2008**	December 31, 2007
Amount owed to TransCanada and its affiliates:		
Great Lakes	**8.1**	1.9
Northern Border	**5.1**	3.0
Tuscarora	**0.5**	3.5

Great Lakes earns transportation revenues from TransCanada and its affiliates under fixed price contracts with remaining terms ranging from one to ten years. Great Lakes earned $40.5 million of transportation revenues under these contracts for the three months ended September 30, 2008 (2007 - $32.4 million). This amount represents 61 per cent of total revenues earned by Great Lakes for the three months ended September 30, 2008 (2007 - 50 per cent). $18.8 million of this transportation revenue is included in our equity income from Great Lakes for the three months ended September 30, 2008 (2007 - $15.1 million).

Great Lakes earned $108.7 million of transportation revenues from TransCanada and its affiliates for the nine months ended September 30, 2008 (February 23, 2007 to September 30, 2007 - $81.5 million). This amount represents 51 per cent of total revenues earned by Great Lakes for the nine months ended September 30, 2008 (February 23, 2007 to September 30, 2007 - 50 per cent). $50.5 million of this transportation revenue is included in our equity income from Great Lakes for the nine months ended September 30, 2008 (February 23, 2007 to September 30, 2007 - $37.9 million). At September 30, 2008, $13.4 million is included in Great Lakes' receivables in regards to the transportation contracts with TransCanada and its affiliates (December 31, 2007 - $10.0 million).

In August 2008, Northern Border sold its wholly-owned subsidiary, Bison Pipeline LLC, to TransCanada for $20.0 million. In connection with this transaction, Northern Border recorded a gain on sale of $16.1 million, of which the Partnership's share is $8.1 million. The proposed 297-mile, 24-inch diameter Bison pipeline system would extend from natural gas gathering facilities located in the Powder River Basin in Wyoming to a point of interconnection with the Northern Border pipeline system in Morton County, North Dakota.

Northern Border's Des Plaines Project consists of the construction, ownership and operation of interconnect facilities, including a 1,600 horsepower compressor facility near Joliet, Illinois. In June 2008, in connection with the Des Plaines Project, Northern Border and ANR Pipeline Company (ANR), a wholly-owned subsidiary of TransCanada, have entered into an Interconnect Agreement, which provides that Northern Border will reimburse ANR for the cost of the interconnect facilities to be owned by ANR. In June, Northern Border paid ANR $0.5 million and it is estimated that additional costs to complete the interconnect will be $0.1 million. Northern Border will be responsible for the final costs to construct the interconnect and any difference between the final actual costs and the estimated amounts paid will be remitted by or refunded to Northern Border.

Note 9 Derivative Financial Instruments

The interest rate swaps and options are structured such that the cash flows match those of the Senior Credit Facility. The notional amount hedged was $475.0 million at September 30, 2008 (December 31, 2007 - $400.0 million). At September 30, 2008, the fair value of the interest rate swaps and options accounted for as hedges was negative $11.5 million (December 31, 2007 – negative $9.8 million). Effective January 1, 2008, we adopted the provisions of Statement of Financial Accounting Standards (SFAS) No. 157, *Fair Value Measurements* (SFAS 157). Under SFAS 157, these financial assets and liabilities that are recorded at fair value on a recurring basis are categorized into one of three categories based upon a fair value hierarchy. We have classified all of our derivative financial instruments as level II where the fair value is determined by using valuation techniques that refer to observable market data or estimated market prices. During the three and nine months ended September 30, 2008, we recorded interest expense of $2.4 million and $4.7 million, respectively, in regards to the interest rate swaps and options. We recorded interest income of $0.4 million and $0.8 million for the three and nine months ended September 30, 2007, respectively, in regards to the interest rate swaps and options.

Note 10 Changes in Working Capital

(unaudited) *(millions of dollars)*	**Nine months ended September 30,** **2008**	2007
Decrease/(increase) in accounts receivable and other	**0.5**	(2.4)
Decrease in bank indebtedness	**(1.4)**	-
Decrease in accounts payable	**(2.6)**	(0.3)
Increase in accrued interest	**0.5**	3.2
	(3.0)	0.5

Note 11 Accounting Pronouncements

In May 2008, the Financial Accounting Standards Board (FASB) issued SFAS No. 162, *The Hierarchy of Generally Accepted Accounting Principles* (SFAS No. 162) which codifies the sources of accounting principles and the related framework to be utilized in preparing financial statements in conformity with GAAP. The requirements of this standard are not expected to have a material impact on our results of operations or financial position.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities* (SFAS No. 161) as an amendment to SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*.

SFAS No. 161 requires that objectives for using derivative instruments be disclosed in terms of underlying risk and accounting designation. SFAS No. 161 is effective for our fiscal year beginning January 1, 2009, and we are currently evaluating its applicability to our results of operations and financial position.

Note 12 Subsequent Events

On October 17, 2008, the Board of Directors of the general partner declared the Partnership's third quarter 2008 cash distribution in the amount of $0.705 per common unit, payable on November 14, 2008, to unitholders of record on October 31, 2008. The cash distribution represents an annual cash distribution of $2.82 per common unit.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discusses the results of operations and liquidity and capital resources of TC PipeLines, LP, along with those of Great Lakes Gas Transmission Limited Partnership (Great Lakes), Northern Border Pipeline Company (Northern Border) and Tuscarora Gas Transmission Company (Tuscarora), (together "our pipeline systems"), as a result of the Partnership's ownership interests.

FORWARD-LOOKING STATEMENTS

The statements in this report that are not historical information, including statements concerning plans and objectives of management for future operations, economic performance or related assumptions, are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Exchange Act. Forward-looking statements may include words such as "anticipate," "estimate," "expect," "project," "intend," "plan," "believe," "forecast" and other words and terms of similar meaning. The absence of these words, however, does not mean that the statements are not forward-looking.

These statements reflect our current views with respect to future events, based on what we believe are reasonable assumptions. Certain factors that could cause actual results to differ materially from those contemplated in the forward-looking statements include:

- the ability of Great Lakes and Northern Border to continue to make distributions at their current levels;
- the impact of unsold capacity on Great Lakes and Northern Border being greater or less than expected;
- competitive conditions in our industry and the ability of our pipeline systems to market pipeline capacity on favorable terms, which is affected by:
    - future demand for and prices of natural gas;
    - competitive conditions in the overall natural gas and electricity markets;
    - availability of supplies of Canadian and United States (U.S.) natural gas;
    - the oversupply of natural gas in the Mid-continent market;
    - availability of additional storage capacity and current storage levels;
    - weather conditions;
    - competitive developments by Canadian and U.S. natural gas transmission companies, including the construction of the Eastern segment of the Rockies Express Pipeline (REX East) to Clarington, Ohio; and
    - development of newly discovered natural gas plays such as the Horn River and Montney shale gas plays in Western Canada, the Louisiana Haynesville shale gas play, and the Marcellus shale gas play in West Virginia, Pennsylvania, and New York.
- the Alberta (Canada) government's decision to implement a new royalty regime effective January 2009 may affect the amount of exploration and drilling in the Western Canada Sedimentary Basin (WCSB);
- the decision by TransCanada to advance the Pathfinder Pipeline Project or the Bison Pipeline Project and the regulatory, financing and construction risks related to construction of interstate natural gas pipelines;
- the successful completion, timing, cost, scope and future financial performance of our pipeline systems' expansion projects could differ materially from our expectations due to availability of contractors or equipment, weather, difficulties or delays in obtaining regulatory approvals or denied applications, land owner opposition, the lack of adequate materials, labor difficulties or shortages, expansion costs that are higher than anticipated and numerous other factors beyond our control;
- performance of contractual obligations by customers of our pipeline systems;
- the imposition of state income taxes on partnerships;
- operating hazards, natural disasters, weather-related delays, casualty losses and other matters beyond our control;
- the impact of current and future laws, rulings and governmental regulations, particularly Federal Energy Regulatory Commission (FERC) regulations, on us and our pipeline systems;
- our ability to control operating costs; and
- prevailing economic conditions, including the current uncertainty in the global economic markets, that impact the capital and equity markets and our ability to access these markets.

Other factors described elsewhere in this document, or factors that are unknown or unpredictable, could also have material adverse effects on future results. Please also read Item 1A. “Risk Factors” in our annual report on Form 10-K for the year ended December 31, 2007 and Item 1A. “Risk Factors” of this report. All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by these factors. The forward-looking statements and information is made only as of the date of the filing of this report, and except as required by applicable law, we undertake no obligation to update these forward-looking statements and information to reflect new information, subsequent events or otherwise.

The following discussion and analysis should be read in conjunction with our 2007 Annual Report on Form 10-K and the unaudited financial statements and notes thereto included in Item 1. “Financial Statements” of this Quarterly Report on Form 10-Q. All amounts are stated in U.S. dollars.

PARTNERSHIP OVERVIEW

TC PipeLines, LP was formed in 1998 as a Delaware limited partnership by TransCanada PipeLines Limited, a wholly-owned subsidiary of TransCanada Corporation (collectively referred to herein as TransCanada), to acquire, own and participate in the management of energy infrastructure assets in North America. Our strategic focus is on delivering stable, sustainable cash distributions to our unitholders and finding opportunities to increase cash distributions while maintaining a low risk profile.

TC PipeLines, LP and its subsidiaries are collectively referred to herein as “TC PipeLines” or “the Partnership.” In this report, references to “we”, “us” or “our” collectively refer to TC PipeLines or the Partnership. The general partner of the Partnership is TC PipeLines GP, Inc., a wholly-owned subsidiary of TransCanada.

We own a 46.45 per cent partner interest in Great Lakes, which we acquired on February 22, 2007 from El Paso Corporation. The other 53.55 per cent general partner interest in Great Lakes is held by TransCanada.

We own a 50 per cent general partner interest in Northern Border, while the other 50 per cent interest is held by ONEOK Partners, L.P., a publicly traded limited partnership that is controlled by ONEOK, Inc.

As of December 31, 2007, we acquired the remaining two per cent general partner interest in Tuscarora, thereby making it a wholly-owned subsidiary.

Our partner interests in Great Lakes, Northern Border and Tuscarora represent our only material assets at September 30, 2008. As a result, we are dependent upon our pipeline systems for all of our available cash. Our pipeline systems derive their operating revenue from transportation of natural gas.

Great Lakes Overview

Great Lakes is a Delaware limited partnership formed in 1990. Great Lakes was originally constructed as an operational loop of the TransCanada Mainline Northern Ontario system. Great Lakes receives natural gas from TransCanada at the Canadian border near Emerson, Manitoba and extends across Minnesota, Northern Wisconsin and Michigan, and redelivers gas to TransCanada at the Canadian border at Sault Ste. Marie, Michigan and St. Clair, Michigan.

Northern Border Overview

Northern Border is a Texas general partnership formed in 1978. Northern Border transports natural gas from the Canadian border near Port of Morgan, Montana to a terminus near North Hayden, Indiana. Additionally, Northern Border transports natural gas produced in the Williston Basin of Montana and North Dakota and the Powder River Basin of Wyoming and Montana and synthetic gas produced at the Dakota Gasification plant in North Dakota.

Tuscarora Overview

Tuscarora is a Nevada general partnership formed in 1993. Tuscarora originates at an interconnection point with existing facilities of Gas Transmission Northwest Corporation, a wholly-owned subsidiary of TransCanada, near Malin, Oregon and runs southeast through Northeastern California and Northwestern Nevada. Tuscarora’s pipeline system terminates near Wadsworth, Nevada. Along its route, deliveries are made in Oregon, Northern California and Northwestern Nevada.

FACTORS THAT IMPACT THE BUSINESS OF OUR PIPELINE SYSTEMS

Key factors that impact the business of our pipeline systems are the supply of and demand for natural gas in the markets in which our pipeline systems operate; the customers of our pipeline systems and the mix of services they require; competition; and government regulation of natural gas pipelines.

Supply and Demand of Natural Gas

Our pipeline systems depend upon the WCSB for the majority of the natural gas that they transport. Overall flows out of the WCSB were lower for the nine months ended September 30, 2008 as compared to the same period last year, due mainly to a decrease in production, and an increase in Canadian demand. WCSB exports are expected to be lower for the remainder of the year. Factors which may mitigate declines related to WCSB production in the future include strengthening gas prices, decreases in oil prices as they affect demand from Alberta oil sands operations, continued clarification of the Alberta Royalty Regime to take effect January 1, 2009 as it affects natural gas production, and announcements regarding potential natural gas supply discoveries in the Horn River and Montney shale gas plays in Western Canada. Reduced supplies available for Canadian export affects all U.S. pipelines that import natural gas from Canada, but the impact on our pipeline systems will depend upon competitive factors and prevailing market conditions in each of the markets that our pipeline systems serve. Flows on Great Lakes' pipeline system in the third quarter of 2008 were consistent with flows in the third quarter of 2007 due to annual contracts and reduced storage inventories which resulted in strong demand for transportation to Michigan and Ontario storage locations. As expected, flows on Northern Border's pipeline system in the third quarter of 2008 were lower than the third quarter of 2007.

The Rockies Express Pipeline is a proposed 1,679-mile natural gas pipeline system from Rio Blanco County, Colorado, to Monroe County, Ohio. The Western segment of the Rockies Express Pipeline (REX West) from Weld County, Colorado to Audrain County, Missouri went into full service in May 2008. REX West has had a minimal impact on Great Lakes; however, it has caused excess natural gas supply from the Rockies Basin to flow into the Mid-Continent market, which is the market served by Northern Border. Consequently, there is less demand for WCSB supply in the Mid-Continent market which has had a negative impact on Northern Border's flows and sales of available capacity in the second and third quarters of 2008. It is anticipated that increased winter demand will dampen the impact of REX West deliveries into the Mid-Continent that has increased supply in Northern Border's market region.

REX East is planned to extend from Audrain County, Missouri to Clarington, located in Monroe County, Ohio. Once in-service, REX East should improve the competitive position of Canadian supply with gas sourced from other supply basins, including the Rockies Basin, into the Mid-Continent, which may potentially mitigate some of the excess supply in the Mid-Continent market. REX East will compete with Great Lakes in some markets, but will also potentially create demand for Great Lakes' transportation of natural gas from REX East seeking access to and from storage locations in Michigan. It is now anticipated that the partial in-service and full in-service of REX East will occur in the second and fourth quarters of 2009, respectively. Although there can be no assurance on the timing or impact of REX East, we believe that any positive impact on the market Northern Border serves will not occur until 2010.

There are many proposed natural gas pipeline projects that, if built, would impact the markets served by our pipeline systems. Two proposed projects, the Pathfinder Pipeline Project (Pathfinder Project) and the Bison Pipeline Project (Bison Project), if built, would diversify Northern Border's natural gas supply sources and provide another transportation source for shippers to export natural gas supply from the Rockies Basin. Please see the Recent Developments disclosure in this section for information on the Bison Project and the Pathfinder Project.

Reduced storage inventories in Eastern Canada and the U.S. supported demand for Great Lakes' transportation, as customers utilized Great Lakes' transportation to access and fill storage locations adjacent to its pipeline in the last quarter.

Great Lakes' future transportation values have continued to increase throughout this year, partially due to the increase in TransCanada Mainline tolls, and partially because of strong spread values between Alberta and Dawn, Ontario. As a result, Great Lakes sold new and renewed long and short haul contracts at maximum tariff rates for the next two years. However, now that Michigan and Ontario storage fill is approaching capacity, as expected for this time of year, daily and short term transportation values are decreasing.

Discoveries of new gas fields, such as the Horn River Basin and Montney gas plays in Western Canada may increase the amount of Canadian natural gas available for export. Recently, TransCanada gauged interest for new natural gas transportation service connecting the Horn River and Montney areas to its Alberta System. TransCanada received requests for gas transmission service exceeding one billion cubic feet per day (Bcf/d) for each area by 2012. Following this, TransCanada launched two binding open seasons seeking requests for firm transportation service from customers for the Groundbirch Project (a pipeline project designed to connect the Montney area of North East British Columbia to TransCanada's Alberta System) and the Horn River Project (a pipeline project designed to connect the Horn River area of North East British Columbia to TransCanada's Alberta system). The Groundbirch Project has an estimated in-service date of late 2010, while the Horn River Project has an estimate in-service date of early 2011. These gas plays, as well as the development of the Louisiana Haynesville shale gas play and the discovery of the Marcellus shale gas play in West Virginia, Pennsylvania, and New York in the U.S. will affect competitive factors and market conditions in the natural gas industry.

Contracting

Great Lakes – Great Lakes' average contracted capacity for the quarter ended September 30, 2008 was 98 per cent of its design capacity (2007 – 98 per cent). For the nine months ended September 30, 2008, Great Lakes' average contracted capacity was 104 per cent of its design capacity (period of March 1, 2007 to September 30, 2007 - 100 per cent). At September 30, 2008, 103 per cent of capacity was contracted on a firm basis for the remainder of the year and the weighted average remaining life of firm transportation contracts was 2.1 years.

In the third quarter of 2008, Great Lakes sold all of its available long haul capacity beginning November 1, 2008 for one year at maximum rates, sold available annual short haul capacity in Michigan at maximum rates for one to two year terms, and sold its available winter seasonal long haul capacity at maximum rates.

Northern Border – Northern Border's average contracted capacity for the quarter ended September 30, 2008 was 79 per cent of its design capacity (2007 - 102 per cent). For the nine months ended September 30, 2008, Northern Border's average contracted capacity was 86 per cent of its design capacity (2007 - 96 per cent). At September 30, 2008, approximately 78 per cent of Northern Border's design capacity was contracted on a firm basis for the remainder of the year and the weighted average remaining contract life of firm transportation contracts was 2.0 years.

At January 1, 2009, Northern Border's total amount of available transportation capacity is expected to be approximately 800 million cubic feet per day (MMcf/d). Northern Border's capacity to Chicago remains attractive and continues to be fully contracted and legacy contracts set to expire in the near term have been renewed. Additionally, related to a proposed expansion project, Northern Border renewed approximately 350 MMcf/d at maximum and discounted rates, for terms ranging from five to twelve years for various transportation paths to Chicago. See additional information below in Recent Developments – Chicago IV Project for more information.

Prevailing market conditions and increasing competitive factors in North America, including REX West, have caused Northern Border to experience a reduction in its revenues due to lower capacity sales and greater discounting of its rates. These factors, as well as expirations of certain long term contracts, will continue to impact Northern Border's ability to market its available capacity into 2009. Northern Border expects to continue to discount transportation capacity as needed to optimize revenue.

Northern Border has executed long-term contracts of approximately 400 MMcf/d sold at a discounted rate from Port of Morgan, Montana to Ventura, Iowa contingent upon either the Bison Project or Pathfinder Project going forward. These contracts would be effective at the successful project's in-service date projected for late 2010.

Tuscarora - Tuscarora's average contracted capacity for the quarter ended September 30, 2008 was 98 per cent of its design capacity (2007 – 95 per cent). For the nine months ended September 30, 2008, Tuscarora's average contracted capacity was 98 per cent of its design capacity (2007 – 96 per cent). At September 30, 2008, approximately 99 per cent of Tuscarora's design capacity was contracted on a firm basis for the remainder of the year and the weighted average remaining contract life of firm transportation contracts was 12.0 years.

RECENT DEVELOPMENTS

Northern Border

Bison Project – On September 3, 2008, Northern Border announced the sale of its wholly-owned subsidiary, Bison Pipeline LLC, to TransCanada Pipeline USA Ltd., a wholly-owned subsidiary of TransCanada for $20.0 million. Distributions paid by Northern Border to its partners in the third quarter included a special distribution in the amount of $16.4 million, of which the Partnership's share was $8.2 million. As a part of the transaction, TransCanada has assumed the obligations of Northern Border related to the Bison Project, and is continuing to solicit commercial support for the Bison Project.

The assets and obligations of Bison Pipeline LLC included executed precedent agreements subject to certain shipper contingencies, as well as regulatory, environmental and engineering activities completed to date on the Bison Project. Shippers on the Bison Project have executed contracts for capacity on the Northern Border system from Port of Morgan, Montana, to Ventura, Iowa, subject to the in-service date of the Bison Project. Project subscription that is subject to the upstream capacity condition is approximately 400 MMcf/d.

The proposed 297-mile, 24-inch diameter Bison pipeline system would extend from natural gas gathering facilities located in the Powder River Basin in Wyoming to a point of interconnection with the Northern Border pipeline system in Morton County, North Dakota. The initial capacity of the Bison Project is anticipated to be approximately 400 MMcf/d. The projected in-service date is late 2010.

The proposed Pathfinder Project is an approximately 673-mile, 36-inch diameter interstate pipeline that would transport natural gas northeast from Meeker, Colorado, through Montana to the Northern Border pipeline system in North Dakota for delivery into the Ventura and Chicago-area markets. The capacity is between 1.2 to 1.6 Bcf/d. In September 2008, Enterprise Product Partners L.P. terminated their previously-announced commitment to become a 50 per cent partner in Pathfinder with a 500 MMcf/d shipping commitment. TransCanada is continuing to work with prospective Pathfinder shippers to advance this project.

The success of either the Bison or Pathfinder Projects is dependent upon many factors, and there is no certainty that either of these projects will be constructed. For further information regarding the risks related to the construction projects, please refer to the Risk Factors sections in our 2007 Annual Report on Form 10-K and in this report.

Proposed Expansion Project (Chicago IV) – Northern Border conducted a binding open season seeking interest in an expansion project from Harper, Iowa to Manhattan, Illinois and received binding shipper commitments. The proposed expansion capacity was subject to a one-time adjustment right to reduce the Chicago IV commitments resulting from the right of first refusal (ROFR) process in current shipper contracts. During a ROFR process, its bidders are able to obtain existing capacity with similar terms. If the Chicago IV bidders reduce their commitments, it could eliminate the need for an expansion project. Northern Border renewed approximately 350 MMcf/d at maximum and discount rates, for terms ranging from 5 to 12 years for various transportation paths to Chicago.

Des Plaines Project – In February 2008, Northern Border filed with the FERC to construct, own and operate interconnect facilities, including a 1,600 horsepower compressor facility near Joliet, Illinois. It is estimated that the Des Plaines Project will cost approximately $18 million and will be financed by a combination of debt and equity. In June 2008, the FERC issued its environmental assessment report for the Des Plaines Project and no comments were filed during the comment period. A certificate order by FERC authorizing construction of the Des Plaines Project was received on July 25, 2008. Northern Border commenced construction on the Des Plaines Project on September 8, 2008, and it is now expected the facilities will be placed into service by early 2009.

Tuscarora

Compressor Station Expansion Project – Tuscarora's compressor station expansion project to support Sierra Pacific Power Company's Tracy Combined Cycle Power Plant went into service on April 1, 2008, with a final cost within the original cost estimate. The new contract for 40,000 Dth/d for a term of 22-1/2 years will generate approximately $5.8 million of annual revenue.

REGULATORY DEVELOPMENTS

Composition of Proxy Groups for Rates of Return Determinations – On July 19, 2007, the FERC issued a policy statement proposing to update its standards regarding the composition of proxy groups for determining the appropriate returns on equity (ROE) for natural gas and oil pipelines, which is used by pipelines to establish rates for services. On April 17, 2008, the FERC issued a policy statement (2008 Policy Statement) that allows master limited partnerships (MLPs) to be included in a proxy group used to determine a pipeline's ROE. The 2008 Policy Statement is effective immediately and provides that there should be no cap on the level of distributions included in the current Discounted Cash Flow (DCF) methodology for MLPs, but there should be an adjustment to the long-term growth rate used to calculate DCF for an MLP (halving the long-term GDP factor which has a one-third weighting in the total growth rate computation in the DCF methodology).

The impact of applying this new policy to our pipeline systems will not be known until one of our pipeline systems files a rate case.

Promotion of a More Efficient Capacity Release Market Docket No. RM08-1 – On June 19, 2008, the FERC issued a Final Rule to modify capacity release regulations (Capacity Release Final Rule). The Capacity Release Final Rule, in addition to other items, allows market-based pricing for short-term capacity releases by shippers through a permanent lifting of the maximum rate cap on short-term capacity releases (of one year or less terms). The Capacity Release Final Rule was effective July 30, 2008.

While implementation of the Capacity Release Final Rule is not expected to have a significant impact on our pipeline systems, the Interstate Natural Gas Association of America (INGAA), of which our pipeline systems are members, filed on July 21, 2008 a request for rehearing of the Capacity Release Final Rule, contending that as the FERC removed the rate cap for short-term released capacity, it should also remove the rate cap for short-term pipeline capacity. INGAA notes that short-term released capacity and short-term pipeline capacity compete in the same market, and argues that removing the rate cap for short-term released capacity and maintaining the cap for short-term pipeline capacity results in a bifurcated and distorted short-term capacity market. On August 15, 2008, the FERC agreed to further consider the issues raised in the rehearing request. A FERC Order is pending on this matter.

Homeland Security – The Department of Homeland Security Appropriations Act of 2007 required the Transportation Security Administration (TSA) to issue regulations establishing risk-based performance standards for the security of chemical and industrial facilities, including oil and gas facilities that were deemed to present high levels of security risk. The TSA will conduct a critical facility identification process, which will include our pipeline systems, anticipated in 2009 or 2010. The TSA has also released a draft of the Pipeline Security Guidelines, which is likely to become regulation in 2009 or 2010. These guidelines distinguish between baseline security requirements for all pipeline facilities and enhanced measures for identified critical facilities. Based on the draft guidelines it is not anticipated that if our pipeline systems are deemed to be critical facilities that there would be a significant additional costs related to compliance.

RESULTS OF OPERATIONS OF TC PIPELINES

Critical Accounting Policies and Estimates

The preparation of financial statements in accordance with Generally Accepted Accounting Principles (GAAP) requires us to make estimates and assumptions with respect to values or conditions which cannot be known with certainty, that affect the reported amount of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements. Such estimates and assumptions also affect the reported amounts of revenue and expenses during the reporting period. Although we believe these estimates and assumptions are reasonable, actual results could differ. There were no significant changes to our critical accounting policies and estimates during the nine months ended September 30, 2008.

Information about our critical accounting estimates is included under Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," in our Annual Report on Form 10-K for the year ended December 31, 2007.

Recent Accounting Pronouncements

In May 2008, the Financial Accounting Standards Board (FASB) issued SFAS No. 162, *The Hierarchy of Generally Accepted Accounting Principles* (SFAS No. 162) which codifies the sources of accounting principles and the related framework to be utilized in preparing financial statements in conformity with GAAP. The requirements of this standard are not expected to have a material impact on our results of operations or financial position.

In March 2008, the FASB issued Statement of Financial Accounting Standards (SFAS) No. 161, *Disclosures about Derivative Instruments and Hedging Activities* (SFAS No. 161) as an amendment to SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*. SFAS No. 161 requires that objectives for using derivative instruments be disclosed in terms of underlying risk and accounting designation. SFAS No. 161 is effective for our fiscal year beginning January 1, 2009, and we are currently evaluating its applicability to our results of operations and financial position.

Net Income

To supplement our financial statements, we have presented a comparison of the earnings contribution components from each of our investments. We have presented net income in this format in order to enhance investors' understanding of the way management analyzes our financial performance. We believe this summary provides a more meaningful comparison of our net income to prior periods, as we account for our partially owned pipeline systems using the equity method. The presentation of this additional information is not meant to be considered in isolation or as a substitute for results prepared in accordance with GAAP.

The shaded areas in the tables below disclose the results from Great Lakes and Northern Border, representing 100 per cent of each entity's operations for the given period.

(unaudited)	**For the three months ended September 30, 2008**					**For the nine months ended September 30, 2008**				
(millions of dollars)	**PipeLP**	TGTC[(1)]	Other	GLGT[(2)]	NBPC[(3)]	**PipeLP**	TGTC[(1)]	Other	GLGT[(2)]	NBPC[(3)]
Transmission revenues	**8.2**	8.2	-	66.7	67.7	**23.3**	23.3	-	213.9	212.8
Operating expenses	**(2.3)**	(1.4)	(0.9)	(17.1)	(19.3)	**(6.8)**	(3.7)	(3.1)	(45.9)	(57.5)
	5.9	6.8	(0.9)	49.6	48.4	**16.5**	19.6	(3.1)	168.0	155.3
Depreciation	**(1.8)**	(1.8)	-	(14.7)	(15.3)	**(5.1)**	(5.1)	-	(43.9)	(45.8)
Financial charges, net and other	**(7.7)**	(1.1)	(6.6)	(8.0)	7.1	**(22.8)**	(3.1)	(19.7)	(24.4)	(12.1)
Michigan business tax	-	-	-	(1.2)	-	-	-	-	(4.2)	-
				25.7	40.2				95.5	97.4
Equity income	**31.9**	-	-	12.0	19.9	**92.5**	-	-	44.4	48.1
Net income	**28.3**	3.9	(7.5)	12.0	19.9	**81.1**	11.4	(22.8)	44.4	48.1

(unaudited)	For the three months ended September 30, 2007					For the nine months ended September 30, 2007				
(millions of dollars)	**PipeLP**	TGTC(1)	Other	GLGT(2)	NBPC(3)	**PipeLP**	TGTC(1)	Other	GLGT(2)	NBPC(3)
Transmission revenues	**6.7**	6.7	-	65.6	79.6	**20.3**	20.3	-	162.2	228.0
Operating expenses	**(2.2)**	(1.2)	(1.0)	(12.6)	(21.6)	**(6.4)**	(3.7)	(2.7)	(34.0)	(61.7)
	4.5	5.5	(1.0)	53.0	58.0	**13.9**	16.6	(2.7)	128.2	166.3
Depreciation	**(1.6)**	(1.6)	-	(14.5)	(15.1)	**(4.7)**	(4.7)	-	(34.9)	(45.6)
Financial charges, net and other	**(8.7)**	(1.0)	(7.7)	(8.1)	(10.2)	**(25.5)**	(3.4)	(22.1)	(19.5)	(30.9)
				30.4	32.7				73.8	89.8
Equity income	**30.4**	-	-	14.2	16.2	**78.6**	-	-	34.3	44.3
Net income	**24.6**	2.9	(8.7)	14.2	16.2	**62.3**	8.5	(24.8)	34.3	44.3

(1) The Partnership owns a 100 per cent general partner interest in Tuscarora Gas Transmission Company (Tuscarora or TGTC) following the acquisition of an additional two per cent interest on December 31, 2007.

(2) The Partnership acquired a 46.45 per cent partner interest in Great Lakes Gas Transmission Limited Partnership (Great Lakes or GLGT) on February 22, 2007.

(3) The Partnership owns a 50 per cent general partner interest in Northern Border Pipeline Company (Northern Border or NBPC). Equity income from Northern Border includes amortization of a $10.0 million transaction fee paid to the operator of Northern Border at the time of the additional 20 per cent acquisition in April 2006.

Third Quarter 2008 compared with Third Quarter 2007

Net income increased $3.7 million, or 15 per cent, to $28.3 million in the third quarter of 2008, compared to $24.6 million in the third quarter of 2007. This increase was primarily due to higher equity income from Northern Border, increased Tuscarora transmission revenues and lower financial charges, net and other, partially offset by decreased equity income from Great Lakes.

Equity income from Great Lakes was $12.0 million in the third quarter of 2008, a decrease of $2.2 million or 15 per cent, compared to $14.2 million for the same period last year. The decrease in equity income was primarily due to increased operating expenses and Michigan business tax (a partnership level tax that was instituted in 2008), partially offset by increased transmission revenues. At Great Lakes' level, operating expenses increased $4.5 million for the three months ended September 30, 2008 compared to the same period last year primarily due to higher taxes other than income, costs related to system integration expenditures and increased pipeline maintenance costs. Michigan business tax of $1.2 million was recorded for the three months ended September 30, 2008. Great Lakes' transmission revenues increased $1.1 million for the three months ended September 30, 2008 compared to the same period last year due primarily to higher short-term revenues from increased sales of daily transport capacity.

Equity income from Northern Border was $19.9 million in the third quarter of 2008, an increase of $3.7 million or 23 per cent, compared to $16.2 million in the same period last year. This is primarily due to a $16.1 million gain on sale of Bison Pipeline LLC and decreased operating expenses, partially offset by lower transmission revenues. At Northern Border's level, operating expenses decreased $2.3 million for the three months ended September 30, 2008 compared to the same period last year primarily due to decreased maintenance costs, decreased electric compressor charges related to lower capacity utilization and decreased taxes other than income. Northern Border's transmission revenues decreased $11.9 million, or 15 per cent, for the three months ended September 30, 2008 compared to the same period last year due primarily to a decrease in system utilization mainly related to natural gas supply from the Rockies Basin into the Mid-Continent market from the in-service of REX West.

Tuscarora's net income was $3.9 million in the third quarter of 2008, an increase of $1.0 million or 34 per cent, compared to $2.9 million in the same period last year. The increase in net income is primarily due to increased transmission revenues resulting from a new firm transportation service contract which supported the Likely compressor station expansion project that went into service on April 1, 2008.

Financial charges, net and other were $7.7 million in the third quarter of 2008, a decrease of $1.0 million or 11 per cent, compared to $8.7 million in the same period last year. This decrease relates primarily to lower interest rates and lower average debt outstanding, partially offset by losses on interest rate derivatives over the same period in 2007.

Nine Months Ended September 30, 2008 compared with Nine Months Ended September 30, 2007

Net income increased $18.8 million, or 30 per cent, to $81.1 million for the nine months ended September 30, 2008, compared to $62.3 million in the same period of 2007. The increase in net income was primarily due to increased equity income from Great Lakes and Northern Border, higher Tuscarora transmission revenues and lower financial charges, net and other.

Equity income from Great Lakes was $44.4 million for the nine months ended September 30, 2008, an increase of $10.1 million or 29 per cent, compared to $34.3 million for the period February 23 to September 30, 2007. The increase in equity income was primarily due to a full first quarter of income contribution in 2008 as compared to 37 days in the first quarter of 2007. In addition, Great Lakes' transmission revenues increased primarily due to increased sales of short term transport capacity, partially offset by costs related to system integration expenditures and increased pipe integrity costs. In the nine months ended September 30, 2008, Great Lakes recorded Michigan business tax of $4.2 million, which is a new partnership level tax that was instituted in 2008.

Equity income from Northern Border was $48.1 million for the nine months ended September 30, 2008, an increase of $3.8 million or 9 per cent, compared to $44.3 million in the same period of 2007. The increase in equity income is primarily due to a $16.1 million gain on sale of Bison Pipeline LLC, and decreased operating expenses, partially offset by lower transmission revenues. At Northern Border's level, operating expenses decreased by $4.2 million in the nine months ended September 30, 2008 compared to the same period last year. This decrease in operating expenses is primarily due to decreased taxes other than income and a $2.3 million transition related charge in 2007 related to the reimbursement for shared equipment and furnishings, partially offset by increased general and administrative expenses and electric compressor charges. Northern Border's transmission revenues decreased by $15.2 million in the nine months ended September 30, 2008 compared to the same period in 2007. This decrease was primarily due to a decrease in contracted capacity mainly related to natural gas supply from the Rockies Basin into the Mid-Continent market from the in-service of REX West.

Tuscarora's net income was $11.4 million for the nine months ended September 30, 2008, an increase of $2.9 million or 34 per cent, compared to $8.5 million in the same period of 2007. The increase in net income is primarily due to increased Tuscarora transmission revenues resulting from a new firm transportation service contract which supported the Likely compressor station expansion that went into service on April 1, 2008.

Financial charges, net and other were $22.8 million for the nine months ended September 30, 2008, a decrease of $2.7 million, or 11 per cent, compared to $25.5 million for the same period of 2007. This decrease relates primarily to lower interest rates and lower average debt outstanding, partially offset by losses on interest rate derivatives over the same period in 2007.

Partnership Cash Flows

The Partnership uses the non-GAAP financial measures 'Partnership cash flows' and 'Partnership cash flows allocated to common units' as financial performance measures. As the Partnership's financial performance underpins the availability of cash flows to fund the cash distributions that the Partnership pays to its unitholders, the Partnership believes these are key measures of the available cash flows to its unitholders. The following Partnership cash flows information is presented to enhance investors' understanding of the way that management analyzes the Partnership's financial performance. Partnership cash flows and Partnership cash flows allocated to common units are provided as a supplement to financial results and are not meant to be considered in isolation or as substitutes for financial results prepared in accordance with GAAP.

(unaudited) *(millions of dollars except per common unit amounts)*	Three months ended September 30, **2008**	2007	Nine months ended September 30, **2008**	2007
Net Income	**28.3**	24.6	**81.1**	62.3
Add:				
Cash flows provided by Tuscarora's operating activities	**7.2**	4.6	**17.3**	13.5
Cash distributions from Great Lakes	**19.3**	17.4	**55.0**	41.0
Cash distributions from Northern Border	**22.6**	14.8	**72.0**	62.5
	49.1	36.8	**144.3**	117.0
Less:				
Tuscarora's net income	**(3.9)**	(2.9)	**(11.4)**	(8.5)
Equity income from investment in Great Lakes	**(12.0)**	(14.2)	**(44.4)**	(34.3)
Equity income from investment in Northern Border	**(19.9)**	(16.2)	**(48.1)**	(44.3)
	(35.8)	(33.3)	**(103.9)**	(87.1)
Partnership cash flows	**41.6**	28.1	**121.5**	92.2
Partnership cash flows allocated to general partner (1)	**(3.2)**	(2.3)	**(8.6)**	(5.3)
Partnership cash flows allocated to common units	**38.4**	25.8	**112.9**	86.9
Cash distributions declared	**(27.8)**	(25.4)	**(83.0)**	(75.4)
Cash distributions declared per common unit (2)	**$ 0.705**	$ 0.660	**$ 2.110**	$ 1.965
Cash distributions paid	**(27.8)**	(25.1)	**(80.8)**	(61.3)
Cash distributions paid per common unit (2)	**$ 0.705**	$ 0.655	**$ 2.070**	$ 1.905
Weighted average common units outstanding *(millions)*	**34.9**	34.9	**34.9**	31.5

(1) Partnership cash flows allocated to general partner represents the cash distributions paid to the general partner with respect to its two per cent interest plus an amount equal to incentive distributions.

(2) Cash distributions declared per common unit and cash distributions paid per common unit are computed by dividing cash distributions, after the deduction of the general partner's allocation, by the number of common units outstanding. The general partner's allocation is computed based upon the general partner's two per cent interest plus an amount equal to incentive distributions.

Third Quarter 2008 compared with Third Quarter 2007

Partnership cash flows increased $13.5 million, or 48 per cent, to $41.6 million for the third quarter of 2008, compared to $28.1 million for the same period last year. This increase was primarily due to higher cash distributions received from Great Lakes and Northern Border, increased cash flows provided by Tuscarora’s operating activities and lower costs at the Partnership level. Cash distributions from Great Lakes and Northern Border increased by $9.7 million in total for the three months ended September 30, 2008 compared with the same period last year. This increase in cash distributions was primarily due to the special distribution of $8.2 million received from Northern Border in relation to the gain on sale of Bison Pipeline LLC. Cash flows provided by Tuscarora’s operating activities increased by $2.6 million for the quarter ended September 30, 2008 compared with the same period last year primarily due to higher transmission revenues resulting from the Likely compressor station expansion project that went into service on April 1, 2008. Costs at the Partnership level decreased by $1.2 million for the quarter ended September 30, 2008 compared with the same period last year primarily due to lower interest rates and lower average debt outstanding, partially offset by losses on interest rate derivatives over the same period in 2007.

During the three months ended September 30, 2008, Tuscarora made capital expenditures of $1.0 million related to the compressor station expansion project in Likely, California compared to $0.9 million for the same period last year. In the third quarter of 2007, a net $1.8 million was received related to the Great Lakes acquisition closing adjustments.

The Partnership paid distributions of $27.8 million in the third quarter of 2008, an increase of $2.7 million, or 11 per cent, compared to $25.1 million for the same period in the prior year due to increases in quarterly per common unit distribution amounts. We repaid a net $3.0 million of the outstanding balance on our debt during the third quarter of 2008 compared to a net issuance of debt of $1.0 million during the same period last year.

Nine Months Ended September 30, 2008 compared with Nine Months Ended September 30, 2007

Partnership cash flows increased $29.3 million, or 32 per cent, to $121.5 million for the nine months ended September 30, 2008, compared to $92.2 million for the same period last year. This increase was primarily a result of increased cash distributions from Great Lakes and Northern Border, increased cash flows provided by Tuscarora's operating activities and decreased costs at the Partnership level.

Cash distributions from Great Lakes were $55.0 million for the nine months ended September 30, 2008, an increase of $14.0 million compared to $41.0 million for the same period last year. The increase in cash distributions from Great Lakes is due primarily to a full nine months of ownership in 2008 compared to the period of February 23 to September 30 for 2007. Cash distributions from Northern Border increased $9.5 million for the nine months ended September 30, 2008 compared to the same period in the prior year due primarily to the special distribution of $8.2 million received from Northern Border in relation to the gain on sale of Bison Pipeline LLC. Cash flows provided by Tuscarora's operating activities increased $3.8 million for the nine months ended September 30, 2008 compared to the same period in the prior year primarily due to the financial results from the Likely compressor station expansion project that went into service on April 1, 2008. Costs at the Partnership level decreased by $2.0 million for the nine months ended September 30, 2008 compared with the same period last year primarily due to lower average debt outstanding and lower interest rates, partially offset by losses on interest rate derivatives and increased general and administrative costs.

During the nine months ended September 30, 2008, Tuscarora made capital expenditures of $6.4 million related to the compressor station expansion project in Likely, California compared to $4.4 million for the same period last year. In February 2007, the Partnership acquired a 46.45 per cent interest in Great Lakes from El Paso Corporation for $733.0 million in cash. In April 2007, the Partnership made a contribution of $7.5 million to Northern Border, representing the Partnership's 50 per cent share of a $15.0 million cash call issued by Northern Border.

The Partnership paid distributions of $80.8 million for the nine months ended September 30, 2008, an increase of $19.5 million, or 32 per cent, compared to $61.3 million for the same period in the prior year due to the increase in the number of common units outstanding, in addition to increases in quarterly per common unit distribution amounts. We repaid a net $27.3 million of the outstanding balance on our debt during the nine months ended September 30, 2008. In 2007, net equity issuances provided $607.0 million, including the general partner's contribution to maintain its two per cent interest, to acquire Great Lakes. The Partnership funded the balance of the acquisition cost with a draw on its senior credit facility.

LIQUIDITY AND CAPITAL RESOURCES OF TC PIPELINES

Overview

Our principal sources of liquidity include distributions received from our investments in Great Lakes and Northern Border, operating cash flows from Tuscarora and our bank credit facility. The Partnership funds its operating expenses, debt service and cash distributions primarily with operating cash flow. Long-term capital needs may be met through the issuance of long-term debt and/or equity.

The Partnership's Debt and Credit Facility

The following table summarizes our debt and credit facility outstanding as of September 30, 2008:

	Payments Due by Period		
(unaudited) *(millions of dollars)*	Total	Less Than 1 Year	Long-term Portion
Senior Credit Facility	482.0	-	482.0
7.13% Series A Senior Notes due 2010	52.9	3.2	49.7
7.99% Series B Senior Notes due 2010	5.3	0.5	4.8
6.89% Series C Senior Notes due 2012	5.9	0.8	5.1
Total	546.1	4.5	541.6

The Senior Credit Facility consists of a $475.0 million senior term loan and a $250.0 million senior revolving credit facility. The interest rate on the Senior Credit Facility averaged 3.31 per cent for the three months ended September 30, 2008 (2007 – 5.97 per cent), while for the nine months ended September 30, 2008 the interest rate on the Senior Credit Facility averaged 3.93 per cent (2007 – 6.02 per cent). After hedging activity, the interest rate incurred on the Senior Credit Facility averaged 5.23 per cent for the three months ended September 30, 2008 (2007 – 5.70 per cent) and 5.18 per cent for the nine months ended September 30, 2008 (2007 – 5.52 per cent). Prior to hedging activities, the interest rate was 3.36 per cent at September 30, 2008 (December 31, 2007 – 5.62 per cent). At September 30, 2008, we were in compliance with our financial covenants.

In spite of the current volatility in the capital markets, neither the Partnership nor its pipeline systems have experienced significant impacts to liquidity or access to the credit markets, although continued volatility in the capital markets may increase costs associated with borrowing.

The Partnership views its core banking group as high quality and has a well-established relationship with these institutions. As of November 3, 2008, the Partnership had no outstanding borrowings under the $250.0 million revolving portion of the Senior Credit Facility. The Partnership has an existing $250.0 million debt and equity shelf expiring December 1, 2008 which it expects to renew in the fourth quarter 2008. This will supplement the $250.0 million of capacity available under the Partnership's existing revolving credit and term loan facility which expires on December 12, 2011.

Interest Rate Swaps and Options

We use derivatives to assist in managing our exposure to interest rate risk. The interest rate swaps and options are structured such that the cash flows match those of the Senior Credit Facility. The notional amount hedged was $475.0 million at September 30, 2008 (December 31, 2007 - $400.0 million). At September 30, 2008, the fair value of the interest rate swaps and options accounted for as hedges was negative $11.5 million (December 31, 2007 – negative $9.8 million). Effective January 1, 2008, we adopted the provisions of Statement of Financial Accounting Standards (SFAS) No. 157, *Fair Value Measurements* (SFAS 157). Under SFAS 157, these financial assets and liabilities that are recorded at fair value on a recurring basis are categorized into one of three categories based upon a fair value hierarchy. We have classified all our derivative financial instruments as level II where the fair value is determined by using valuation techniques that refer to observable market data or estimated market prices. During the three and nine months ended September 30, 2008, we recorded interest expense of $2.4 million and $4.7 million, respectively, in regards to the interest rate swaps and options. We recorded interest income of $0.4 million and $0.8 million for the three and nine months ended September 30, 2007, respectively, in regards to the interest rate swaps and options.

2008 Third Quarter Cash Distribution

On October 17, 2008, the Board of Directors of the general partner declared the Partnership's 2008 third quarter cash distribution. The third quarter cash distribution will be paid on November 14, 2008 to unitholders of record as of October 31, 2008, totaling $27.8 million and will be paid in the following manner: $24.6 million to common unitholders (including $1.4 million to the general partner as holder of 2,035,106 common units and $6.1 million to TransCan Northern Ltd. as holder of 8,678,045 common units), $2.6 million to the general partner as holder of the incentive distribution rights, and $0.6 million to the general partner in respect of its two per cent general partner interest.

2009 Capital Requirements

Northern Border's distribution policy adopted in 2006 defines minimum equity to total capitalization to be used by the Management Committee to establish the timing and amount of required equity contributions. In accordance with this policy and in anticipation of the equity financing of Northern Border's Des Plaines Project, Northern Border currently estimates an equity contribution of approximately $85 million in the upcoming year, of which the Partnership's share would be approximately $43 million. The Partnership expects to finance this equity contribution with a combination of debt and operating cash flows.

LIQUIDITY AND CAPITAL RESOURCES OF OUR PIPELINE SYSTEMS

Overview

Our pipeline systems’ principal source of liquidity is cash generated from operating activities and bank credit facilities. Our pipeline systems fund their operating expenses, debt service and cash distributions to partners primarily with operating cash flow.

Capital expenditures are funded by a variety of sources, including cash generated from operating activities, borrowings under bank credit facilities, issuance of senior notes or equity contributions from our pipeline systems’ partners. The ability of our pipeline systems to access capital markets for debt under reasonable terms depends on their financial condition, credit ratings and market conditions.

Our pipeline systems believe that their ability to obtain financing at reasonable rates and their history of consistent cash flow from operating activities provide a solid foundation to meet their future liquidity and capital resource requirements. The Partnership’s pipeline systems monitor the creditworthiness of their customers and have credit provisions included in their tariffs, which allow them to request credit support as circumstances dictate. Additionally, Northern Border has established relationships with high-quality banks, which are involved in its revolving credit facility and provide liquidity for Northern Border’s operating needs.

Debt of Great Lakes

The following table summarizes Great Lakes’ debt outstanding as of September 30, 2008:

	Payments Due by Period		
(unaudited) *(millions of dollars)*	Total	Less than 1 year	Long-term Portion
8.74% series Senior Notes due 2008 to 2011	40.0	10.0	30.0
6.73% series Senior Notes due 2009 to 2018	90.0	9.0	81.0
9.09% series Senior Notes due 2012 to 2021	100.0	-	100.0
6.95% series Senior Notes due 2019 to 2028	110.0	-	110.0
8.08% series Senior Notes due 2021 to 2030	100.0	-	100.0
Total	440.0	19.0	421.0

Great Lakes is required to comply with certain financial, operational and legal covenants. Under the most restrictive covenants in the Senior Note Agreements, approximately $237.0 million of Great Lakes’ partners’ capital was restricted as to distributions as of September 30, 2008. At September 30, 2008, Great Lakes was in compliance with all of its financial covenants.

Debt, Credit Facility and Contractual Obligations of Northern Border

The following table summarizes Northern Border's debt and credit facility outstanding as of September 30, 2008:

	Payments Due by Period		
(unaudited) *(millions of dollars)*	Total	Less than 1 year	Long-term Portion
7.75% senior notes due 2009	200.0	200.0	-
7.50% senior notes due 2021	250.0	-	250.0
$250 million credit agreement due 2012[a]	172.0	-	172.0
Total	622.0	200.0	422.0

[a] Northern Border is required to pay a facility fee of 0.05% on the principal commitment amount of its credit agreement.

Revolving Credit Agreement
As of September 30, 2008, Northern Border had outstanding borrowings of $172.0 million under its $250 million revolving credit agreement and was in compliance with the covenants of the agreement. The weighted average interest rate related to the borrowings on the credit agreement was 2.99 per cent at September 30, 2008.

Senior Notes due 2009
On September 1, 2009, the $200.0 million 7.75 per cent senior notes will mature. As market conditions dictate, Northern Border will finance the repayment by use of fixed-rate debt, variable-rate debt or a combination of fixed-rate and variable-rate debt.

Interest Rate Collar Agreement
At September 30, 2008, Northern Border's balance sheet reflected an unrealized loss of approximately $2.2 million with a corresponding increase to accumulated other comprehensive loss related to the changes in fair value of its zero cost interest rate collar agreement (the "Collar Agreement") since inception. During the three and nine months ended September 30, 2008, Northern Border recorded interest expense of $0.5 million and $1.3 million, respectively, under the Collar Agreement. Hedge ineffectiveness had no impact on income for the three and nine months ended September 30, 2008.

Contractual Obligations
Northern Border has commitments totaling approximately $2.2 million in relation to the Des Plaines Project at September 30, 2008, with total expected costs to be approximately $18 million. Half of the project costs will be financed under Northern Border's credit facility and the other half by equity contributions from its partners. See section entitled "Recent Developments" in Item 2. "Management's Discussion and Analysis of Financial Condition and Results of Operations" for further discussion of this project.

RELATED PARTY TRANSACTIONS

Great Lakes earns transportation revenues from TransCanada and its affiliates under fixed price contracts with remaining terms ranging from one to ten years. Great Lakes earned $40.5 million of transportation revenues under these contracts for the three months ended September 30, 2008 (2007 - $32.4 million). This amount represents 61 per cent of total revenues earned by Great Lakes for the three months ended September 30, 2008 (2007 - 50 per cent). $18.8 million of this transportation revenue is included in our equity income from Great Lakes for the three months ended September 30, 2008 (2007 - $15.1 million).

Great Lakes earned $108.7 million of transportation revenues from TransCanada and its affiliates for the nine months ended September 30, 2008 (February 23, 2007 to September 30, 2007 - $81.5 million). This amount represents 51 per cent of total revenues earned by Great Lakes for the nine months ended September 30, 2008 (February 23, 2007 to September 30, 2007 - 50 per cent). $50.5 million of this transportation revenue is included in our equity income from Great Lakes for the nine months ended September 30, 2008 (February 23, 2007 to September 30, 2007 - $37.9 million). At September 30, 2008, $13.4 million is included in Great Lakes' receivables in regards to the transportation contracts with TransCanada and its affiliates (December 31, 2007 - $10.0 million).

Please read Note 8 within Item 1. "Financial Statements" for additional information regarding related party transactions.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

OVERVIEW

Our exposure to market risk discussed below includes forward-looking statements and represents an estimate of possible changes in future earnings that would occur assuming hypothetical future movements in interest rates. Our views on market risk are not necessarily indicative of actual results that may occur and do not represent the maximum possible gains and losses that may occur, since actual gains and losses will differ from those estimated, based on actual fluctuations in interest rates and the timing of transactions.

We are exposed to market risk due to interest rate fluctuations. Market risk is the risk of loss arising from adverse changes in market rates. We utilize financial instruments to manage the risks of certain identifiable or anticipated transactions to achieve a more predictable cash flow. Our risk management function follows established policies and procedures to monitor interest rates to ensure our hedging activities mitigate market risks. We do not use financial instruments for trading purposes.

In accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* we record financial instruments on the balance sheet as assets and liabilities based on fair value. We estimate the fair value of financial instruments using available market information and appropriate valuation techniques. Changes in financial instruments' fair value are recognized in earnings unless the instrument qualifies as a hedge under SFAS No. 133 and meets specific hedge accounting criteria. Qualifying financial instruments' gains and losses may offset the hedged items' related results in earnings for a fair value hedge or be deferred in accumulated other comprehensive income for a cash flow hedge.

INTEREST RATE RISK

Our interest rate exposure results from our Senior Credit Facility, which is subject to variability in London Interbank Offered Rate (LIBOR) interest rates. We regularly assess the impact of interest rate fluctuations on future cash flows and evaluate hedging opportunities to mitigate our interest rate risk. The notional amount hedged at September 30, 2008 was $475.0 million. The interest rate swaps and options are structured such that the cash flows match those of the Senior Credit Facility. The fair value of interest rate derivatives has been calculated using period-end market rates. At September 30, 2008, the fair value of our interest rate swaps and options accounted for as hedges was negative $11.5 million.

At September 30, 2008, we had $482.0 million outstanding on our Senior Credit Facility. Utilizing the conditions of the interest rate swaps and options, if LIBOR interest rates hypothetically increased by one per cent (100 basis points) compared to the rates in effect as of September 30, 2008, our annual interest expense would have increased and our net income would have decreased by $0.1 million; and if LIBOR interest rates hypothetically decreased by one per cent (100 basis points) compared to the rates in effect as of September 30, 2008, our annual interest expense would have decreased and our net income would have increased by $0.1 million. This amount has been determined by considering the impact of the hypothetical interest rates on variable rate borrowings outstanding as of September 30, 2008.

Northern Border utilizes both fixed-rate and variable-rate debt and is exposed to market risk due to the floating interest rates on its credit facility. Northern Border regularly assesses the impact of interest rate fluctuations on future cash flows and evaluates hedging opportunities to mitigate its interest rate risk. As of September 30, 2008, 72 per cent of Northern Border's outstanding debt was at fixed rates. Northern Border utilizes its Collar Agreement to limit the variability of the interest rate on $140.0 million of variable-rate borrowings.

Utilizing the conditions of the Collar Agreement, if interest rates hypothetically increased one per cent (100 basis points) compared with rates in effect as of September 30, 2008, Northern Border's annual interest expense would increase and its net income would decrease by approximately $0.3 million; and if interest rates hypothetically decreased one per cent (100 basis points) compared with rates in effect as of September 30, 2008, Northern Border's annual interest expense would decrease and its net income would increase by approximately $0.3 million.

Great Lakes and Tuscarora utilize fixed-rate debt; therefore, they are not exposed to market risk due to floating interest rates.

OTHER RISKS

The Partnership is influenced by the same factors that influence our pipeline systems. None of our pipeline systems own any of the natural gas they transport; therefore, they do not assume any of the related natural gas commodity price risk.

The state of Minnesota currently requires Great Lakes to pay use tax on the value of the shipper provided compressor fuel burned in its Minnesota compressor engines. Great Lakes is subject to primarily commodity price volatility and some volume volatility in determining the amount of use tax owed. If natural gas prices changed by $1 per million British thermal units, Great Lakes' annual use tax expense would change by approximately $0.7 million.

The Partnership does not have any material foreign currency exchange risks.

Item 4. Controls and Procedures

EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

Based on their evaluation of the Partnership's disclosure controls and procedures as of the end of the period covered by this quarterly report, the principal executive officer and principal financial officer of the general partner of the Partnership have concluded that the Partnership's disclosure controls and procedures were effective in ensuring that the information required to be disclosed by the Partnership in the reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's (SEC's) rules and forms and that information required to be disclosed by the Partnership in the reports that the Partnership files or submits under the Exchange Act is accumulated and communicated to the management of the general partner of the Partnership, including the principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

During the quarter ended September 30, 2008, there has been no change in the Partnership's internal control over financial reporting that has materially affected or is reasonably likely to materially affect our internal control over financial reporting.

PART II – OTHER INFORMATION

Item 1A. Risk Factors

Our business is subject to the risks described below and the risk factors disclosed in Part I, Item 1A. "Risk Factors," in our Annual Report on Form 10-K for the year ended December 31, 2007.

The following new risk factor should be read in conjunction with the risk factors disclosed in Part I, Item 1A. "Risk Factors," in our Annual Report on Form 10-K for the year ended December 31, 2007:

The current capital and credit market conditions may adversely affect the Partnership or our pipeline systems' access to capital and cost of capital.

Access to capital markets is important to the Partnership to enable it to execute its business strategies, which include seeking opportunities to undertake accretive acquisitions and organic growth projects, and maximize the value of our existing portfolio of pipeline systems. Access to capital markets is important to our pipeline systems' ability to operate and Northern Border expects to refinance $200 million of Senior Notes in 2009. In October 2008, the general economic and capital market conditions in the United States and other parts of the world have deteriorated significantly and have adversely affected access to capital and increased the cost of capital. If these conditions continue or become worse, the Partnership's and our pipeline systems' future cost of debt and equity capital, and future access to capital markets could be adversely affected.

The following updated risk factors should be read in conjunction with the risk factors disclosed in Part I, Item 1A. "Risk Factors," in our Annual Report on Form 10-K for the year ended December 31, 2007:

The long-term financial conditions of our pipeline systems are dependent on the continued availability of Western Canadian natural gas for import into the U.S. and the market demand for these volumes. Competition from pipelines that deliver natural gas from other supply sources to our pipeline systems' market areas could cause our pipeline systems to discount their rates or otherwise experience a reduction in their revenues.

The development of additional natural gas reserves requires significant capital expenditures by others for exploration and development drilling and the installation of production, gathering, storage, transportation and other facilities that permit natural gas to be produced and delivered to pipelines that interconnect with our pipeline systems. High exploration and production costs, low prices for natural gas, regulatory limitations such as royalty frameworks, or the lack of available capital for these projects could adversely affect the development of additional reserves in Western Canada and the production in the WCSB.

Volumes available for export out of the WCSB depend in part on the internal demand for Canadian natural gas which may increase as a result of increased demand for electricity generation and other industrial requirements, including the development of oil sands projects, which may require substantial amounts of natural gas. This higher internal demand may reduce the amount of gas available for import into the U.S. In the longer term, a portion of the Alberta hub gas supply may come from proposed gas pipelines from the North Slope of Alaska and the Mackenzie Delta of Canada and from the continued growth of coal bed methane projects. Cancellation or delays in the construction of such pipelines or such projects could adversely affect the volumes available for export in the long term.

If the availability of Alberta hub natural gas was to decline, existing shippers on our pipeline systems may be unlikely to extend their contracts and our pipeline systems may be unable to find replacement shippers for lost capacity. Furthermore, additional natural gas reserves may not be developed in commercial quantities and in sufficient amounts to fill the capacities of each of our pipeline systems.

In addition, existing customers may not extend their contracts if the cost of delivered natural gas from other producing regions into the markets served by our pipeline systems is lower than the cost of natural gas delivered by our pipeline systems. Our pipeline systems face increased competition from other pipelines that provide access for our shippers to capacity from the U.S. Rocky Mountain Region. The Rockies Express Pipeline owned by Rockies Express Pipeline LLC is being constructed in two phases and the planned terminus is in Clarington, Ohio. REX West is completed and is currently delivering gas to interconnects in the Midwestern region. The full in-service of REX West in May 2008 has resulted in significant downward pressure on natural gas prices in the Mid-continent Region, and is having a negative impact on demand for Northern Border's transport and may have an impact on Great Lakes in the future.

REX East is planned to extend from Audrain County, Missouri to Clarington in Monroe County, Ohio. Once in-service, REX East should improve the competitive position of Canadian supply with Mid-Continent sourced gas, potentially mitigating some of the excess supply in the Mid-Continent market. REX East will compete in some of Great Lakes' markets, but will also potentially create demand for Great Lakes' transportation of natural gas from REX East seeking access to and from storage locations in Michigan. It is now anticipated that the partial in-service and full in-service of REX East will occur in the second and fourth quarters of 2009, respectively. Although there can be no assurance on the timing or impact of REX East, we believe that any positive impact on the market Northern Border serves will not occur until 2010.

An increase in competition in the key markets served by our pipeline systems could arise from new ventures or expanded operations from existing competitors. Our financial performance depends to a large extent on the capacity contracted on our pipeline systems. Decreases in the volumes transported by our pipeline systems, whether caused by supply or demand factors in the markets these pipeline systems serve, competition or otherwise, can directly and adversely affect our revenues and results of operations.

Our pipeline systems may undertake expansion and build projects which involve significant risks that could adversely affect our business. Additionally, the Bison Project and the Pathfinder Project have inherently similar risks that may impact their success and therefore the potential volumes to be delivered to Northern Border.

Our pipeline systems have expansion and new build projects planned or underway, including Northern Border's $18 million Des Plaines Project. Additionally, expansion and new build projects, such as the Bison and/or Pathfinder Projects that would potentially deliver gas to Northern Border, are subject to a variety of factors outside their control, such as weather, natural disasters, delays in obtaining key materials and difficulties in obtaining permits and rights-of-way or other regulatory approvals, as well as the performance by third party contractors may result in increased costs or delays in construction. Cost overruns or delays in completing a project could result in reduced transportation rates and liquidated damages to customers, as well as lost revenue opportunities. In addition, we cannot be certain that, if completed, these projects will perform in accordance with our expectations. Each of these risks could have a material adverse effect on our results of operations and cash flows.

If our pipeline systems were to become subject to a material amount of entity level taxation for state tax purposes, then our pipeline systems' operating cash flow and cash available for distribution to us and for other business needs would be reduced.

Our pipeline systems are partnerships or tax flow through entities, and as such they generally have not been subject to income tax at the entity level. Several states have either adopted or are evaluating a variety of ways to subject partnerships to entity level taxation. For example, in the nine months ended September 30, 2008, Great Lakes recorded a Michigan business tax of $4.2 million relating to a new partnership level tax, of which the Partnership's share of the tax was $2.0 million. Imposition of such taxes on our pipeline systems will reduce the cash available for distribution to us and for other business needs by our pipeline systems.

Unitholders will likely be subject to state and local taxes as a result of an investment in units.

In addition to federal income taxes, unitholders will likely be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property. We may be required to withhold income taxes with respect to income allocable or distributions made to our unitholders. In addition, unitholders may be required to file state and local income tax returns and pay state and local income taxes in some or all of the jurisdictions in which we do business or own property and may be subject to penalties for failure to comply with those requirements. It is the unitholders' responsibility to file all required United States federal, state and local tax returns. Counsel has not rendered an opinion on the state or local tax consequences of an investment in us.

Item 6. Exhibits

No.	Description
10.1	Membership Interest Purchase Agreement as of August 28, 2008, by and between Northern Border Pipeline Company and TransCanada Pipeline USA Ltd.
10.2	First Amendment to Amended and Restated Revolving Credit Agreement dated as of July 31, 2008 between Northern Border Pipeline Company and the lenders named therein.
31.1	Certification of Principal Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Principal Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of Principal Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Principal Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

SIGNATURES

Pursuant to the requirements of the Securities and Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

TC PipeLines, LP
(a Delaware Limited Partnership)

By: TC PipeLines GP, Inc., its general partner

Date: November 3, 2008

By: /s/ Russell K. Girling
Russell K. Girling
Chairman, Chief Executive Officer and Director
TC PipeLines GP, Inc. (Principal Executive Officer)

Date: November 3, 2008

By: /s/ Amy W. Leong
Amy W. Leong
Controller
TC PipeLines GP, Inc. (Principal Financial Officer)

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Section 2: EX-10.1 (MEMBERSHIP INTEREST PURCHASE AGREEMENT)

Exhibit 10.1

Execution Copy

MEMBERSHIP INTEREST PURCHASE AGREEMENT

by and between

NORTHERN BORDER PIPELINE COMPANY

and

TRANSCANADA PIPELINE USA LTD.

Dated as of August 28, 2008

HOU:2825092.15

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MEMBERSHIP INTEREST PURCHASE AGREEMENT

THIS MEMBERSHIP INTEREST PURCHASE AGREEMENT (this "Agreement") is made and entered into as of August 28, 2008, by and between **Northern Border Pipeline Company**, a Texas general partnership ("Seller"), and **TransCanada PipeLine USA Ltd.**, a Nevada corporation ("Purchaser").

RECITALS

WHEREAS, Seller is the sole member of Bison Pipeline LLC, a Delaware limited liability company ("Bison"), and desires to sell its 100% membership interest in Bison (the "Interest") to Purchaser on the terms and conditions set forth herein; and

WHEREAS, Purchaser desires to purchase the Interest from Seller on the terms and conditions set forth herein; and

NOW, THEREFORE, in consideration of the foregoing recitals and the mutual promises, representations, warranties, and covenants hereinafter set forth and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereto, intending to be legally bound, hereby agree as follows:

AGREEMENT

ARTICLE I

DEFINITIONS

For purposes of this Agreement, the following terms have the meanings specified or referred to in this Article I.

"Affiliate" means, with respect to any Person, (a) each Person controlled by such Person, (b) each Person that controls such Person and (c) each Person that is under common control with such Person.

"Alternate Agreements" has the meaning given to such term in Section 2.1.

"Anadarko" means Anadarko Energy Services Company, a Delaware corporation.

"Approval Date" has the meaning given to such term in Section 5.2.

"Bison" has the meaning given to such term in the recitals.

"Bison Agreement" has the meaning given to such term in Section 3.2.

"Bison Open Season" means the terms and conditions defining the service to be provided on the Bison Project and posted on the Seller's website.

"Bison Project" means the pipeline project being developed by Bison to transport natural gas from the Powder River Basin to the Seller's pipeline system and having FERC Docket No. PF08-23-000.

"Closing" has the meaning given to such term in Section 2.2.

"Closing Date" has the meaning given to such term in Section 2.2.

"Code" means the Internal Revenue Code of 1986, as amended.

"Consent" means any approval, consent, permit, ratification, waiver, order or other authorization.

"Contemplated Transactions" means the purchase and sale of the Interest and the performance by Seller and Purchaser of their other obligations under this Agreement.

"Damages" means all damages, penalties, fines, costs, amounts paid in settlement, Liabilities, obligations, Taxes, liens, losses, expenses and fees (including court costs and costs of investigation, defense and reasonable attorneys' fees and expenses) actually incurred, but specifically excluding special, incidental, consequential and punitive damages, as reduced by any insurance recoveries received in respect thereof.

"Dollars" means United States Dollars.

"FERC' means the Federal Energy Regulatory Commission.

"Governmental Body" means any:

(a) nation, state, county, city, town, district or other jurisdiction of any nature;

(b) federal, state, local, municipal, foreign or other government;

(c) governmental or quasi-governmental authority of any nature (including any governmental agency, branch, department, official or entity and any court or other tribunal); or

(d) body exercising, or entitled to exercise, any administrative, executive, judicial, legislative, police, regulatory or taxing authority or power of any nature.

"Indemnity Period" has the meaning given to such term in Section 6.1.

"Initial Payment" has the meaning given to such term in Section 2.1.

"Interest" has the meaning given to such term in the recitals.

"Knowledge" means, with respect an individual's knowledge of a particular fact or other matter, that such individual is actually aware of such fact or other matter, and with respect to the knowledge of a Person other than an individual of a particular fact or other matter, that any individual who is serving as a director, manager or executive officer of such Person is actually aware of such fact or other matter.

"Legal Requirement" means any federal, state, local, municipal, foreign, international or other administrative order, constitution, law, ordinance, regulation, statute or treaty applicable to a Person.

"Liability" means any liability (whether absolute or contingent, liquidated or unliquidated, or due or to become due, or otherwise), including any liability for Taxes.

"Lien" has the meaning given to such term in Section 3.4.

"MERC" means Minnesota Energy Resources Corporation, a Delaware corporation.

"MMBtu" means one million British thermal units.

"MMcf" means one million cubic feet of natural gas.

"Pathfinder Project" means the pipeline construction and development project proposed by Purchaser that upon completion will transport natural gas from Meeker, Colorado and/or Wamsutter, Wyoming to the Seller's pipeline system, terminating at a point near the Seller's compression station in Morton County, North Dakota and that has FERC Docket No. PF08-22-000.

"Person" means any individual, corporation (including any non-profit corporation), general or limited partnership, limited liability company, joint stock company, joint venture, estate, trust, association, organization, other entity or Governmental Body.

"Post-Closing Payment" has the meaning given to such term in Section 2.1.

"Post-Effective Date Development Costs" has the meaning given to such term in Section 2.3.

"Pre-Effective Date Development Costs" has the meaning given to such term in Section 2.3.

"Proceeding" means any action, arbitration, audit, hearing, investigation, litigation or suit (whether civil, criminal, or administrative) commenced, brought, conducted or heard by or before, or otherwise involving, any Governmental Body or arbitrator.

"Purchase Price" has the meaning given to such term in Section 2.1.

"Purchaser" has the meaning given to such term in the preamble.

"Representative" means, with respect to a particular Person, any director, officer, manager, employee, agent, consultant, advisor or other representative of such Person, including legal counsel, accountants and financial advisors.

"Securities Act" has the meaning given to such term in Section 4.6.

"Seller" has the meaning given to such term in the preamble.

"Tax" means any federal, state, local, or foreign income, gross receipts, license, payroll, employment, excise, severance, stamp, occupation, premium, windfall profits, environmental, customs duties, capital stock, franchise, profits, withholding, social security (or similar), unemployment, disability, real property, personal property, sales, use, transfer, registration, value added, alternative or add-on minimum, estimated or other tax of any kind whatsoever, including any interest, penalty or addition thereto, whether disputed or not.

"Tax Return" means any return, declaration, report, claim for refund, or information return or statement relating to Taxes filed or required to be filed with any taxing authority, including any schedule or attachment thereto, and including any amendment thereof.

"Threatened" means that a demand or statement has been made in writing, or any notice has been given in writing, asserting that a claim, Proceeding, dispute, action or other matter may be commenced or taken in the future.

"Transfer Taxes" has the meaning given to such term in Section 5.6(b).

"Williams" means Williams Gas Marketing, Inc., a Delaware corporation

ARTICLE II

AGREEMENT TO SELL AND PURCHASE

2.1 Sale and Purchase.

Subject to the terms and conditions hereof, at the Closing Seller hereby agrees to sell the Interest to Purchaser, and Purchaser agrees to purchase the Interest from Seller, for a total purchase price of Twenty Million Dollars (US$20,000,000) (the "Purchase Price"). Purchaser agrees that it will pay the Purchase Price as follows: (a) Thirteen Million Five Hundred Thousand Dollars (US$13,500,000) (the "Initial Payment") shall be paid by Purchaser to Seller at the Closing by wire transfer of immediately available funds to an account designated in writing to Purchaser by Seller and (b) Six Million Five Hundred Thousand Dollars (US$6,500,000) (the "Post-Closing Payment") shall be paid by Purchaser to Seller, by wire transfer of immediately available funds to an account designated in writing to Purchaser by Seller, within ten (10) days of the earlier to occur of (i) the satisfaction, expiration, termination or waiver by MERC, by August 29, 2008, of the contingency set forth in MERC's Anchor Shipper Offer Sheet, which is attached to Exhibit B to the Precedent Agreement for Firm Natural Gas Transportation Service dated May 22, 2008 by and between MERC and Bison or (ii) the execution, on or before the Approval Date, of one or more third-party firm transportation precedent agreements with an aggregate maximum delivery quantity of at least 50 MMcf per day from the Powder River Basin on terms and conditions no less favorable than those offered to shippers in the Bison Open Season and having no material conditions outstanding or not otherwise satisfied, other than conditions that are within the control of Purchaser (the "Alternate Agreements"); *provided* that such Alternate Agreements may include a firm transportation precedent agreement by MERC to transport at least 50 MMcf per day on either the Bison Project or the Pathfinder Project that is a substitute arrangement for that described in clause (i) of this sentence if such agreement by MERC contains terms and conditions no less favorable than those offered to shippers in the Bison Open Season and has no material conditions outstanding or not otherwise satisfied, other than conditions that are within the control of Purchaser. For the avoidance of doubt, it is acknowledged and agreed that Purchaser will only be required to pay the Post-Closing Payment upon satisfaction of the conditions set forth in either of clauses (b)(i) or (ii) of this Section 2.1, and that if the conditions set forth in neither of such clauses are satisfied, the Purchase Price will consist only of the Initial Payment.

2.2 Closing.

The closing of the sale and purchase of the Interest under this Agreement (the "Closing") shall take place at 10:00 a.m. Omaha, Nebraska time on August 29, 2008, at the offices of Seller, 13710 FNB Parkway, Omaha, Nebraska 68154, or at such other time or place as Seller and Purchaser may mutually agree (such date is hereinafter referred to as the "Closing Date"). At the Closing, subject to the terms and conditions hereof, Seller and Purchaser will deliver an executed Bill of Sale and Assignment and Assumption Agreement substantially in the form of Exhibit A hereto with respect to the Interest to be purchased at the Closing by Purchaser, upon payment of the Initial Payment by wire transfer of immediately available funds to an account designated in writing to Purchaser by Seller.

2.3 Effective Date; Development Costs.

Regardless of the Closing Date, the Contemplated Transactions shall have an effective date of July 31, 2008. Seller shall assume and pay all development costs and expenses relating to the Bison Project that are incurred by Bison or by Seller on behalf of Bison at any time prior to 12:00 a.m. CDT on August 1, 2008 ("Pre-Effective Date Development Costs"). Purchaser shall assume and pay all reasonable and documented development costs and expenses relating to the Bison Project that are incurred by Bison or by Seller on behalf of Bison at any time commencing after 12:00 a.m. CDT on August 1, 2008 ("Post-Effective Date Development Costs"), provided that the Closing occurs. On or before the date that is ninety (90) days after the Closing Date, Seller shall provide to Purchaser a written accounting of all Pre-Effective Date Development Costs and Post-Effective Date Development Costs, and shall identify those Post-Effective Date Development Costs already paid by Bison or by Seller on behalf of Bison. Purchaser shall reimburse Seller, by wire transfer of immediately available funds to an account designated in writing to Purchaser by Seller, for all Post-Effective Date Development Costs paid by Bison or by Seller on behalf of Bison within ten (10) days of Seller's receipt of such written accounting.

2.4 Conditions to Obligations of Purchaser.

Purchaser's obligation to purchase the Interest at the Closing is subject to the satisfaction or waiver, at or prior to the Closing Date, of the following conditions:

(a) Approval by Purchaser. The Board of Directors of Purchaser shall have authorized and approved (a) the execution, delivery and performance by Purchaser of this Agreement and the Contemplated Transactions and (b) the Bison Project. Purchaser acknowledges that this condition has been satisfied.

(b) Certain Proceedings. No Proceeding shall have been commenced against Seller or Bison that challenges, or may have the effect of preventing, delaying, making illegal or otherwise interfering with, any of the Contemplated Transactions.

(c) ONEOK Letter. Seller shall have delivered to Purchaser a letter from ONEOK Partners Intermediate Limited Partnership in the form of Exhibit B attached hereto.

(d) Closing Documents. Seller shall have delivered to Purchaser, at the Closing, (i) an Assistant Secretary's Certificate, reasonably satisfactory to Purchaser, certifying the approvals described in Section 2.5(a), (ii) an Officers' Certificate, signed by two duly authorized officers of the operator of Seller, stating that the representations and warranties of Seller contained herein are true and correct as of the Closing Date as if made on the Closing Date and that Seller has performed all of its covenants and obligations set forth herein that are to be performed by it at or before the Closing, and (iii) pursuant to Section 1445 of the Code, a tax certificate that (1) states that Seller is not a foreign corporation, foreign partnership, foreign trust or foreign estate and (2) provides Seller's employer identification number and address.

2.5 Conditions to Obligations of Seller.

Seller's obligation to sell the Interest at the Closing is subject to the satisfaction or waiver, on or prior to the Closing Date, of the following conditions:

(a) Approval by Seller. The Management Committee of Seller shall have authorized and approved the execution, delivery and performance by Seller of this Agreement and the Contemplated Transactions.

(b) Certain Proceedings. No Proceeding shall have been commenced against Purchaser that challenges, or may have the effect of preventing, delaying, making illegal or otherwise interfering with, any of the Contemplated Transactions.

(c) Closing Documents. Purchaser shall have delivered to Seller, at the Closing, (i) a Certificate, reasonably satisfactory to Seller, certifying the approvals described in Section 2.4(a) and (ii) an Officers' Certificate, signed by two duly authorized officers of Purchaser, stating that the representations and warranties of Purchaser contained herein are true and correct as of the Closing Date as if made on the Closing Date and that Purchaser has performed all of its covenants and obligations set forth herein that are to be performed by it at or before the Closing.

2.6 Purchase Price Allocation for Tax Purposes.

Within one hundred eighty (180) days after the Closing Date, Purchaser shall provide to Seller a copy of Internal Revenue Service Form 8594 and any required exhibits thereto with Purchaser's prepared allocation of the Purchase Price. Purchaser and Seller agree to make all reasonable efforts to file all Tax Returns of both Purchaser and Seller consistently with this allocation.

ARTICLE III

REPRESENTATIONS AND WARRANTIES OF SELLER

Seller represents and warrants to Purchaser that:

3.1 Organization.

Seller is a general partnership duly formed, validly existing and in good standing under the laws of the State of Texas.

3.2 Organization and Qualification of Bison.

Bison is a limited liability company duly formed, validly existing and in good standing under the laws of the State of Delaware and is duly authorized to conduct business, duly registered or qualified and in good standing under the laws of each jurisdiction where the nature of its assets or business requires it to be so authorized, registered or qualified, except where the failure to be so authorized, registered or qualified would not reasonably be expected to impair Seller's ability to consummate the Contemplated Transactions. Bison has the full limited liability company power and authority to own or hold its properties and assets and to carry on its business as currently conducted. Seller has delivered to Purchaser correct and complete copies of the Certificate of Formation of Bison, the Limited Liability Company Agreement, dated March 27, 2008, of Bison (the "Bison Agreement"), and any other organizational documents of Bison.

3.3 Authority.

Seller has the full partnership power and authority to enter into this Agreement and to perform its obligations hereunder. The execution, delivery and performance of this Agreement by Seller have been duly and validly authorized by all necessary partnership action. Assuming the due and valid authorization, execution and delivery of this Agreement by Purchaser, this Agreement constitutes the legal, valid and binding obligation of Seller, enforceable against Seller in accordance with its terms, except as such enforceability may be limited by (a) applicable bankruptcy, insolvency, reorganization, moratorium and other laws of general application affecting enforcement of creditors' rights generally and (b) laws relating to the availability of equitable remedies.

3.4 Ownership.

Seller is the sole member of Bison and the legal and beneficial owner of the Interest, which has been duly and validly authorized and issued in accordance with the Bison Agreement; Seller owns such membership interest free and clear of all liens, encumbrances, security interests, equities, charges or claims (collectively, "Liens"); and at the Closing, upon payment of the Purchase Price, Seller will deliver to Purchaser good, valid and marketable title to the Interest, free and clear of any Liens. Except (a) as provided in the Bison Agreement, (b) as provided in Anadarko's Precedent Agreement for Firm Natural Gas Transportation Service, dated May 23, 2008, with Bison and (c) for the Contemplated Transactions, there are no outstanding or authorized options, warrants, purchase rights, conversion rights, preemptive rights, exchange rights or other contracts or commitments to sell, subscribe for or purchase any equity interest in Bison, and there are no restrictions upon the transfer of the Interest.

3.5 No Conflicts or Violations; Consents.

Neither the execution and delivery of this Agreement by Seller nor the performance by Seller of its obligations hereunder (a) conflicts or will conflict with, or constitutes or will constitute a violation of, the general partnership agreement of Seller, certificate of formation of Seller or Bison, limited liability company agreement of Bison or other organizational document of Seller or Bison, (b) conflicts or will conflict with, constitutes or will constitute a breach of or default under (or an event that, with notice or lapse of time or both, would constitute such a breach of or default under), or provides or will provide any party the right to accelerate, terminate, modify or cancel, any indenture, mortgage, deed of trust, loan agreement, lease or other agreement or instrument to which Seller or Bison is a party, by which either of them is bound or to which any of their properties or assets is subject, (c) violates or will violate any statute, law, ordinance, regulation, order, judgment, decree or injunction of any court or Governmental Body to which Seller, Bison or any of their properties or assets may be subject or (d) will result in the creation or imposition of any Lien upon the Interest or any of the property or assets of Seller or Bison. Neither Seller nor Bison is required to provide any notice to or obtain any Consent from any Person in connection with the consummation of the Contemplated Transactions, except for such notices or Consents where the failure to provide such notice or obtain such Consent would not reasonably be expected to impair its ability to consummate the Contemplated Transactions.

3.6 Certain Proceedings.

There is no pending Proceeding that has been commenced against Seller or Bison that challenges, or may have the effect of preventing, delaying, making illegal or otherwise interfering with, any of the Contemplated Transactions. To the Knowledge of Seller, no such Proceeding has been Threatened.

3.7 Brokers or Finders.

Seller and its officers and agents have incurred no obligation or liability, contingent or otherwise, for brokerage or finders' fees or agents' commissions or other similar payment in connection with this Agreement.

3.8 Taxes.

Except as would not reasonably be expected to have a material adverse effect, (a) Seller has filed, or caused to be filed, all Tax Returns required to be filed by Bison or with respect to its assets or operations on a timely basis (taking into account all extensions of due dates), (b) all such Tax Returns were complete and correct, (c) all Taxes owed by Bison which are or have become due have been timely paid in full, (d) there are no Liens on the Interest or any of Bison's assets that arose in connection with any failure (or alleged failure) to pay any Tax on any such assets or with respect to the Interest, other than Liens for Taxes not yet due and payable, (e) there is no pending action, proceeding or, to the Knowledge of Seller, investigation for assessment or collection of Taxes and no Tax assessment, deficiency or adjustment has been asserted or proposed with respect to Bison or its assets, (f) Bison, since its inception, has been disregarded as an entity separate from Seller for federal income tax purposes under Treasury Regulations 3017701-2 and -3 and any comparable provisions of state and local jurisdictions that permit such treatment and (g) there is no tax allocation agreement or tax sharing agreement to which Bison is a party.

ARTICLE IV

REPRESENTATIONS AND WARRANTIES OF PURCHASER

Purchaser represents and warrants to Seller as follows:

4.1 Organization.

Purchaser is a corporation duly organized, validly existing, and in good standing under the laws of the State of Nevada.

4.2 Authority.

Purchaser has the full corporate power and authority to enter into this Agreement and to perform its obligations hereunder. The execution, delivery and performance of this Agreement by Purchaser have been duly and validly authorized by all necessary corporate action. Assuming the due and valid authorization, execution and delivery of this Agreement by Seller, this Agreement constitutes the legal, valid and binding obligation of Purchaser, enforceable against Purchaser in accordance with its terms, except as such enforceability may be limited by (a) applicable bankruptcy, insolvency, reorganization, moratorium and other laws of general application affecting enforcement of creditors' rights generally and (b) laws relating to the availability of equitable remedies.

4.3 No Conflicts or Violations; Consents.

Neither the execution and delivery of this Agreement by Purchaser nor the performance by Purchaser of its obligations hereunder (a)conflicts or will conflict with, or constitutes or will constitute a violation of, the certificate or articles of incorporation, bylaws or other organizational document of Purchaser, (b) conflicts or will conflict with, constitutes or will constitute a breach of or default under (or an event that, with notice or lapse of time or both, would constitute such a breach of or default under), or provides or will provide any party the right to accelerate, terminate, modify or cancel, any indenture, mortgage, deed of trust, loan agreement, lease or other agreement or instrument to which Purchaser is a party, by which Purchaser is bound or to which any of its properties or assets is subject, (c) violates or will violate any statute, law, ordinance, regulation, order, judgment, decree or injunction of any court or Governmental Body to which Purchaser or any of its properties or assets may be subject or (d) will result in the creation or imposition of any Lien upon any of the property or assets of Purchaser. Purchaser is not required to provide any notice to or obtain any Consent from any Person in connection with the consummation of the Contemplated Transactions, except for such notices or Consents where the failure to provide such notice or obtain such Consent would not reasonably be expected to impair its ability to consummate the Contemplated Transactions.

4.4 Certain Proceedings.

There is no pending Proceeding that has been commenced against Purchaser that challenges, or may have the effect of preventing, delaying, making illegal or otherwise interfering with, any of the Contemplated Transactions. To the Knowledge of Purchaser, no such Proceeding has been Threatened.

4.5 Brokers or Finders.

Purchaser and its officers and agents have incurred no obligation or liability, contingent or otherwise, for brokerage or finders' fees or agents' commissions or other similar payment in connection with this Agreement.

4.6 Investment Intent; Access.

Purchaser acknowledges that (a) the Interest has not been registered under the Securities Act of 1933, as amended (the "Securities Act"), or any state securities laws, and (b) Seller has disclosed to Purchaser that the Interest may not be resold absent such registration or unless an exemption from registration is available. Purchaser is acquiring the Interest for its own account, for investment purposes only and not with a view to its distribution within the meaning of the Securities Act. Purchaser has such knowledge and experience in financial and business matters that it is capable of evaluating the merits and risks of the Contemplated Transactions. Seller has made available to Purchaser and its Representatives the opportunity to ask questions of the officers and Representatives of Seller, to engage in diligence and to acquire such additional information about the business, assets and financial condition of Seller as Purchaser has requested, and all such requested information has been received by Purchaser.

ARTICLE V

COVENANTS OF THE PARTIES

5.1 Expenses.

Except as contemplated by Section 2.3, each party shall bear its own expenses incurred in connection with the preparation, execution and performance of this Agreement and the Contemplated Transactions, including all fees and expenses of agents, counsel, accountants and other Representatives.

5.2 Pathfinder Project.

Provided that (a) Bison has entered into firm transportation precedent agreements with respect to the Bison Project with an aggregate maximum delivery quantity of at least 405 MMcf per day and that have no material conditions outstanding or not otherwise satisfied by August 31, 2008 (unless otherwise extended by Purchaser), other than conditions that are within the control of Purchaser, and (b) Purchaser has not, by September 30, 2008 (or such other later date agreed to by the Bison and Pathfinder shippers) (the "Approval Date"), received management approval to proceed with the Pathfinder Project, Purchaser will, subject to the rights and obligations of Bison set forth in the Precedent Agreements for Firm Natural Gas Transportation Service executed with the Bison shippers, use commercially reasonable efforts to complete the Bison Project and place it in-service during the fourth quarter of 2010.

5.3 Northern Border Pipeline Company Capacity.

Subject to Seller's tariff and applicable law, Seller shall use commercially reasonable efforts to assist Purchaser after the Closing by marketing existing capacity on Seller's pipeline system and the potential expansion of its pipeline system to shippers, including, but not limited to, shippers on the Bison Project and/or the Pathfinder Project. Commercially reasonable efforts shall consist of (a) the continuation at least until September 30, 2008 of the offer to all shippers of a discounted reservation rate on Seller's pipeline system of US$0.23 per MMBtu for transportation from Port of Morgan to Ventura for a ten (10) year commitment, (b) initiating the applicable right of first refusal process for capacity on Seller's pipeline system to Chicago during the month of September 2008 and (c) Seller offering the market, including, but not limited to, shippers on the Bison Project and/or the Pathfinder Project, an open season having a bid period during the month of August 2008 proposing the expansion of Seller's pipeline system for transportation on Seller's pipeline system to Chicago for a ten (10) year commitment with a targeted in-service date of the fourth quarter of 2010, or as soon as practicable thereafter. Such capacity shall be offered at a rate that the Seller reasonably believes to be marketable; *provided* that Seller's obligation under this Agreement to undertake any such expansion shall be subject to a fair and reasonable return analysis by Seller relating to the expected economics of any such expansion and the approval of its Management Committee.

5.4 Discussions with Shippers.

Seller shall assist Purchaser in discussions with the existing shippers on the Bison Project in order to assist with the satisfaction of the outstanding conditions precedent under such shippers' firm transportation precedent agreements and encourage their participation in the Pathfinder Project; *provided* that Seller's obligations pursuant to this Section 5.4 shall be expressly limited to participating in conversations and shall not include any obligation to undertake or incur any liabilities or expenses or to make concessions of any kind to shippers.

5.5 Further Assurances.

Each party agrees (a) to furnish upon request to the other party such further information, (b) to execute and deliver to the other party such other documents and (c) to do such other acts and things, in each case as the other party may reasonably request for the purpose of carrying out the intent of this Agreement and the Contemplated Transactions.

5.6 Tax Matters.

The following provisions shall govern the allocation of responsibility between Seller and Purchaser for certain Tax matters following the Closing Date:

(a) Tax Returns.

(i) Seller shall prepare or cause to be prepared and file or cause to be filed all Tax Returns for Bison for periods ending on or before the Closing Date that are required to be filed after the Closing Date, and shall be responsible for the timely payment (and entitled to any refund) of Taxes due with respect to the period covered by such Tax Returns.

(ii) Seller shall prepare or cause to be prepared and file or cause to be filed any Tax Returns of Bison for periods which begin before the Closing Date and end after the Closing Date, shall furnish a copy of such Tax Return to Purchaser. Seller shall be responsible for the timely payment of Taxes due with respect to the period covered by such Tax Return allocable to the period prior to and including the Closing Date, and Purchaser shall be responsible for the timely payment of Taxes due with respect to the period after the Closing Date.

(iii) To the extent permitted by law or administrative practice, the taxable year of Bison shall end on and include the Closing Date. Whenever it is necessary to determine the liability for Taxes of Bison for a portion of a taxable year or period that begins before and ends after the Closing Date, the determination of the Taxes for the portion of the year or period ending on, and the portion of the year or period beginning after, the Closing Date shall be determined by assuming that the taxable year or period ended on and included the Closing Date, except that exemptions, allowances or deductions that are calculated on an annual basis and annual property taxes shall be prorated on the basis of the number of days in the annual period elapsed through the Closing Date as compared to the number of days in the annual period elapsing after the Closing Date.

(iv) Any Tax Return to be prepared pursuant to the provisions of this Section 5.6 shall be prepared in a manner consistent with practices followed in prior years with respect to similar Tax Returns, except for changes required by changes in law or fact. Purchaser shall not file an amended Tax Return for any period ending on or prior to the Closing Date without the consent of Seller, which consent shall not be unreasonably withheld or delayed.

(b) Transfer Taxes. Purchaser shall be responsible for the payment of all excise, sales, use, transfer (including real property transfer or gains), stamp, documentary, filing, recordation and other similar taxes, together with any interest, additions or penalties with respect thereto and any interest in respect of such additions or penalties, resulting directly from the Contemplated Transactions (collectively, "Transfer Taxes").

(c) Access to Information. After the Closing Date, Seller shall grant to Purchaser (or its designees) access at all reasonable times to all of the information, books, and records relating to Bison within the possession of Seller (including work papers and correspondence with taxing authorities), and shall afford Purchaser (or its designees) the right (at Purchaser's expense) to take extracts therefrom and to make copies thereof, to the extent reasonably necessary to permit Purchaser (or its designees) to prepare Tax Returns and to conduct negotiations with taxing authorities. After the Closing Date, Purchaser shall grant or cause Bison to grant to Seller (or its designees) access at all reasonable times to all of the information, books and records relating to Bison within the possession of Purchaser or Bison (including work papers and correspondence with taxing authorities), and shall afford Seller (or its designees) the right (at Seller's expense) to take extracts therefrom and to make copies thereof, to the extent reasonably necessary to permit Seller (or its designees) to prepare Tax Returns and to conduct negotiations with taxing authorities.

(d) Survival. Anything to the contrary in this Agreement notwithstanding, the representations, warranties, covenants, agreements, rights and obligations of the parties with respect to any Tax matter covered by this Agreement shall survive the Closing and shall not terminate until ninety (90) days after the expiration of the applicable statutes of limitations (including all periods of extension and tolling) applicable to such Tax matter.

(e) Conflict. In the event of a conflict between the provisions of this Section 5.6 and any other provisions of this Agreement, the provisions of this Section 5.6 shall control.

(f) Tax Indemnity.

(i) Seller shall be liable for, and shall indemnify and hold Bison and Purchaser and its Affiliates harmless from, any Taxes (other than Transfer Taxes) (1) imposed on or incurred by or with respect to Bison or its assets with respect to the period prior to and including the Closing Date, (2) attributable to a breach by Seller of any covenant with respect to Taxes in this Agreement or (3) attributable to a breach of Seller's representations and warranties in Section 3.8.

(ii) Purchaser shall be liable for, and shall indemnify and hold Seller and its Affiliates harmless from, any Taxes (including Transfer Taxes) attributable to a breach by Purchaser of any covenant with respect to Taxes in this Agreement.

(iii) If Purchaser or its Affiliates receive a refund of any Taxes that Seller is responsible for hereunder, or if Seller or its Affiliates receive a refund of any Taxes that Purchaser is responsible for hereunder, the party receiving such refund shall, within ninety (90) days after receipt of such refund, remit it to the party who has responsibility for such Taxes hereunder. The parties shall cooperate in order to take all necessary steps to claim any such refund.

ARTICLE VI

INDEMNIFICATION; REMEDIES

6.1 Survival of Representations, Warranties and Covenants.

The representations, warranties and covenants set forth in this Agreement shall survive until the expiration of the period (the "Indemnity Period") that commences on the Closing Date and terminates on the date that is one hundred eighty (180) days after the Closing Date, at which time they will expire; *provided*, *however*, that the Indemnity Period with respect to the covenant set forth in Section 5.2 shall extend until January 15, 2011; and *provided*, *further*, that the Indemnity Period with respect to the representations and warranties set forth in Section 3.8 and the covenants set forth in Section 5.6 shall extend until ninety (90) days after the expiration of the applicable statute of limitations. Neither party shall have any liability (for indemnification or otherwise) with respect to any representation or warranty, or any covenant or obligation to be performed or complied with by it hereunder, unless on or before the expiration or termination of the Indemnity Period, the other party notifies such party of a claim, specifying the factual basis of that claim in reasonable detail to the extent then known by it.

6.2 Indemnification and Payment of Damages by Seller.

Subject to the limitations set forth in this Article VI, Seller shall indemnify Purchaser and its Representatives and Affiliates for, shall hold Purchaser and its Representatives and Affiliates harmless from, and shall pay to Purchaser and its Representatives and Affiliates the amount of, any Damages arising from or in connection with (a) any inaccuracy in or breach of any representation or warranty made by Seller in this Agreement or (b) any breach of any covenant or agreement of Seller in this Agreement.

6.3 Indemnification and Payment of Damages by Purchaser.

Subject to the limitations set forth in this Article VI, Purchaser shall indemnify Seller and its Representatives and Affiliates for, shall hold Seller and its Representatives and Affiliates harmless from, and shall pay to Seller and its Representatives and Affiliates the amount of, any Damages arising from or in connection with (a) any inaccuracy in or breach of any representation or warranty made by Purchaser in this Agreement or (b) any breach of any covenant or agreement of Purchaser in this Agreement.

6.4 Limitations on Indemnification.

Neither party shall have any liability (for indemnification or otherwise) with respect to any representation, warranty, covenant or agreement made in this Agreement until the total of all Damages asserted by the other party with respect to all such matters exceeds $500,000 in the aggregate, and then the liable party shall be liable for such Damages only to the extent they exceed such amount. The limitations set forth in the preceding sentence shall not apply to a breach of the representations and warranties set forth in Section 3.8 or the covenants set forth in Section 5.6, any fraudulent representations and warranties made in this Agreement or any willful breach of any covenant or agreement made in this Agreement, and the liable party shall be liable for all Damages with respect thereto. In no event shall the aggregate liability of either party for breach of its representations, warranties, covenants and agreements exceed fifteen percent (15%) the Purchase Price, except in the case of fraud or a breach of representations and warranties set forth in Section 3.8 or the covenants set forth in Section 5.6.

6.5 No Security Holder Liability.

The parties acknowledge that the stockholders, members, and other security holders of Purchaser and Seller are not parties to this Agreement and that the representations, warranties, covenants and agreements made in this Agreement are provided only by Seller or Purchaser, as the case may be, to the other. The parties agree that neither party shall have recourse (including for indemnification or otherwise) against any officer, director, stockholder, member, manager or security holder of the other party under or in connection with this Agreement.

ARTICLE VII

GENERAL PROVISIONS

7.1 Public Announcements.

The initial press release or releases to be issued in connection with the Contemplated Transactions shall be agreed upon by the parties prior to the issuance thereof. Otherwise, prior to the Closing, neither party shall, without the other party's prior written consent (which shall not be unreasonably withheld or delayed) or unless permitted by the Confidentiality Agreement, dated July 18, 2008, between the parties or any amendments thereto or waivers therefrom, make any disclosure concerning this Agreement or the Contemplated Transactions to any Person other than (a) their respective members, managers, officers, directors or employees who have a need to know in connection with this Agreement or (b) their respective counsel, public accountants and financial advisors.

7.2 Confidentiality.

. Each party hereto shall hold, and shall cause its Representatives to hold, in strict confidence, unless compelled to disclose by judicial or administrative process or, in the opinion of its counsel, by other Legal Requirements, and not use for its own advantage, any information about the other provided in or pursuant to this Agreement, except to the extent that such information can be shown to have been generally available to the public other than as a result of a disclosure by such party or its Representatives.

7.3 Notices.

All notices, consents, waivers and other communications under this Agreement must be in writing and shall be deemed to have been duly given when (a) delivered by hand (with written confirmation of receipt), (b) sent by facsimile transmission (with written confirmation of receipt), provided that a copy is also mailed or (c) received by the addressee, if sent by a nationally recognized overnight delivery service (receipt requested), in each case to the addresses and facsimile numbers set forth below (or to such other addresses and facsimile numbers as a party may designate by notice to the other party):

Seller:

Northern Border Pipeline Company
P.O. Box 542500
Omaha, NE 68154-8500
Attention: Eva Neufeld
Facsimile No.: (402) 492-7480

with a copy (which shall not constitute notice) to:

Andrews Kurth LLP
600 Travis, Suite 4200
Houston, Texas 77002
Attention: Mike O'Leary
Facsimile No.: (713) 238-7130

HOU:2825092.15

and

ONEOK Partners, L.P.
100 West 5th Street
Tulsa, Oklahoma 74103-4298
Attention: General Counsel
Facsimile No.: (918) 588-7971

Purchaser:

TransCanada PipeLine USA Ltd.
717 Texas Avenue, Suite 2400
Houston, Texas 77252-2446
Attention: Kelly Jameson
Facsimile No.: (713) 420-6548

with a copy (which shall not constitute notice) to:

TransCanada PipeLines Limited
450 1st Street SW
Calgary, Alberta
Canada
Attention: Ron Anderson
Facsimile No.: (403) 920-2363

7.4 Waiver.

Neither the failure to exercise, nor any delay in exercising, any right, power or privilege by either party under this Agreement shall operate as a waiver of such right, power, or privilege, and no single or partial exercise of any such right, power or privilege shall preclude any other or further exercise of such right, power or privilege or the exercise of any other right, power, or privilege. To the maximum extent permitted by applicable law, except as otherwise expressly provided herein, (a) no claim or right arising out of this Agreement can be discharged by one party, in whole or in part, by a waiver or renunciation of the claim or right unless in writing signed by the other party, (b) no waiver that may be given by a party shall be applicable except in the specific instance for which it is given and (c) no notice to or demand on one party shall be deemed to be a waiver of any obligation of such party or of the right of the party giving such notice or demand to take further action without notice or demand as provided in this Agreement.

7.5 Entire Agreement and Modification.

This Agreement supersedes all prior agreements between the parties with respect to its subject matter and constitutes a complete and exclusive statement of the terms of the agreement between the parties with respect to its subject matter. This Agreement may not be amended except by a written agreement executed by each of the parties.

7.6 Assignments; Successors; No Third-Party Rights.

Neither party may assign any of its rights under this Agreement without the prior consent of the other party; *provided* that Purchaser may assign its rights to any Affiliate of Purchaser without Seller's consent so long as Purchaser remains obligated to Seller pursuant to the terms and conditions of this Agreement and such Affiliate expressly assumes the obligations of Purchaser hereunder. Any attempted assignment of this Agreement or any of the rights hereunder in violation of the foregoing shall be voidable by the non-assigning party. Subject to the preceding sentences, this Agreement will apply to, be binding in all respects upon, and inure to the benefit of the successors and permitted assigns of the parties. Nothing expressed or referred to in this Agreement will be construed to give any Person other than the parties to this Agreement any legal or equitable right, remedy or claim under or with respect to this Agreement or any provision of this Agreement. This Agreement and all of its provisions and conditions are for the sole and exclusive benefit of the parties to this Agreement and their successors and permitted assigns.

7.7 Severability.

If any provision of this Agreement is held invalid or unenforceable by any court of competent jurisdiction, the other provisions of this Agreement shall remain in full force and effect. Any provision of this Agreement held invalid or unenforceable only in part or degree shall remain in full force and effect to the extent not held invalid or unenforceable.

7.8 Article and Section Headings; Construction.

The headings of Articles and Sections in this Agreement are provided for convenience only and will not affect its construction or interpretation. All references to "Article" or "Section" refer to the corresponding Article or Section of this Agreement. All words used in this Agreement will be construed to be of such gender or number as the circumstances require. Unless otherwise expressly provided, the word "including" does not limit the preceding words or terms. The terms and provisions of this Agreement represent the results of negotiations between the parties, each of which has been represented by counsel of its own choosing, and none of which has acted under duress or compulsion, whether legal, economic or otherwise. Accordingly, the terms and provisions of this Agreement shall be interpreted and construed in accordance with their usual and customary meanings, and the parties hereby waive the application, in connection with the interpretation and construction of this Agreement, of any rule of law to the effect that ambiguous or conflicting terms or provisions contained in this Agreement shall be interpreted or construed against the party whose attorney prepared the executed draft or any earlier draft of this Agreement.

7.9 Time of Essence.

With regard to all dates and time periods set forth or referred to in this Agreement, time is of the essence.

7.10 Enforcement.

Each party agrees that it will not bring any action against the other party hereto relating to this Agreement in any court other than the United States District Court for the District of Delaware or a Delaware state court located in Wilmington, Delaware. Each party (a) submits unconditionally to the exclusive jurisdiction of the state and federal courts located in Wilmington, Delaware, (b) waives and agrees not to assert any objection to the venue of any proceeding in any such court and agrees not to assert that any such court provides an inconvenient forum and (c) waives any right to trial by jury with respect to any claim or proceeding related to or arising out of this Agreement.

7.11 Governing Law.

This Agreement shall be governed by, and construed and enforced in accordance with, the laws of the State of Delaware without regard to conflicts of laws principles that would apply any other law.

7.12 Counterparts.

This Agreement may be executed in one or more counterparts, each of which shall be deemed to be an original copy of this Agreement and all of which, when taken together, shall be deemed to constitute one and the same agreement.

7.13 No Other Representations; Disclaimers.

NOTWITHSTANDING ANYTHING TO THE CONTRARY CONTAINED IN THIS AGREEMENT, IT IS THE EXPLICIT INTENT AND AGREEMENT OF EACH PARTY HERETO THAT SELLER IS MAKING NO REPRESENTATION OR WARRANTY WHATSOEVER, EXPRESS OR IMPLIED, INCLUDING BUT NOT LIMITED TO ANY IMPLIED REPRESENTATION OR WARRANTY AS TO CONDITION, MERCHANTABILITY, USAGE, SUITABILITY OR FITNESS FOR ANY PARTICULAR PURPOSE, WITH RESPECT TO THE INTEREST, BISON, ITS ASSETS, OR ANY PART THEREOF, EXCEPT THOSE REPRESENTATIONS AND WARRANTIES OF SELLER CONTAINED IN ARTICLE III HEREOF. IN PARTICULAR, SELLER MAKES NO REPRESENTATION OR WARRANTY TO PURCHASER WITH RESPECT TO ANY FINANCIAL PROJECTION, FORECAST OR FORWARD-LOOKING STATEMENT.

7.14 Waiver of Certain Damages.

IN NO EVENT WILL EITHER PARTY OR ITS SECURITY HOLDERS, DIRECTORS, OFFICERS, EMPLOYEES, MEMBERS, MANAGERS, AGENTS OR REPRESENTATIVES BE LIABLE TO THE OTHER PARTY OR ITS SECURITY HOLDERS, DIRECTORS, OFFICERS, EMPLOYEES, MEMBERS, MANAGERS, AGENTS OR REPRESENTATIVES UNDER THIS AGREEMENT AT ANY TIME FOR PUNITIVE, CONSEQUENTIAL, SPECIAL, OR INDIRECT LOSSES OR DAMAGES, INCLUDING LOSS OF PROFIT, LOSS OF REVENUE OR ANY OTHER SPECIAL OR INCIDENTAL DAMAGES, WHETHER IN CONTRACT, TORT (INCLUDING NEGLIGENCE), STRICT LIABILITY OR OTHERWISE.

[*Signature page follows*]

IN WITNESS WHEREOF, the parties hereto have executed this Membership Interest Purchase Agreement as of the date first set forth above.

SELLER:

Northern Border Pipeline Company

By: **TransCanada Northern Border Inc., its Operator**

By: /s/ Paul F. Miller
Name: Paul F. Miller
Title: Vice President and General Manager

By: /s/ Patricia M. Wiederholt
Name: Patricia M. Wiederholt
Title: Principal Financial Officer and Controller

PURCHASER:

TransCanada PipeLine USA Ltd.

By: /s/ Donald R. Marchand
Name: Donald R. Marchand
Title: Treasurer

By: /s/ Donald J.DeGrandis
Assistant Secretary

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Section 3: EX-10.2 (FIRST AMENDMENT TO AMENDED AND RESTATED REVOLVING CREDIT AGREEMENT)

Exhibit 10.2

FIRST AMENDMENT TO AMENDED AND RESTATED REVOLVING CREDIT AGREEMENT

THIS FIRST AMENDMENT TO AMENDED AND RESTATED REVOLVING CREDIT AGREEMENT (this "***Amendment***"), is made and entered into as of July 31, 2008, by and among NORTHERN BORDER PIPELINE COMPANY, a Texas general partnership (the "***Borrower***"), the several banks and other financial institutions from time to time party hereto (collectively, the "***Lenders***"), SUNTRUST BANK, in its capacity as Administrative Agent for the Lenders (the "***Administrative Agent***"), as issuing bank (the "***Issuing Bank***") and as swingline lender (the "***Swingline Lender***"), WACHOVIA BANK, NATIONAL ASSOCIATION, as syndication agent (the "***Syndication Agent***") and BMO CAPITAL MARKETS, CITIBANK, N.A., and MIZUHO CORPORATE BANK, LTD., as Co-Documentation Agents.

W I T N E S S E T H:

WHEREAS, the Borrower, the Lenders, the Swingline Lender, the Issuing Bank, the Administrative Agent and the other agents party thereto are parties to a certain Amended and Restated Revolving Credit Agreement, dated as of April 27, 2007 (as amended, restated, supplemented or otherwise modified from time to time, the "***Credit Agreement***"; capitalized terms used herein and not otherwise defined shall have the meanings assigned to such terms in the Credit Agreement), pursuant to which the Lenders and the Issuing Bank have made certain financial accommodations available to the Borrower;

WHEREAS, the Borrower has requested that the Lenders, the Swingline Lender, the Issuing Bank and the Administrative Agent amend certain provisions of the Credit Agreement, and subject to the terms and conditions hereof, the Lenders are willing to do so;

NOW, THEREFORE, for good and valuable consideration, the sufficiency and receipt of all of which are acknowledged, the Borrower, the Lenders, the Swingline Lender, the Issuing Bank and the Administrative Agent agree as follows:

1. **Amendments**.

(a) Section 1.1of the Credit Agreement is hereby amended by adding the following definition of Bison Pipeline Acquisition Agreement in the appropriate alphabetical order:

> "Bison Pipeline Acquisition Agreement" shall mean that certain acquisition agreement between the Borrower and TransCanada Pipeline USA Ltd. or its wholly owned subsidiary in form and substance satisfactory to the Administrative Agent and on terms substantially similar to those set out in the indication of interest letter dated as of July 28, 2008 between the Borrower and TransCanada Pipeline USA Ltd., pursuant to which the Borrower sells all of the membership interests it owns in Bison Pipeline LLC to TransCanada Pipeline USA Ltd. or its wholly owned subsidiary.

(b) Section 7.3(b) of the Credit Agreement is hereby amended by replacing subsection B of such Section in its entirety with the following:

(b) The Borrower shall not lease, sell or otherwise dispose of its assets to any other Person except: (i) sales of inventory and other assets in the ordinary course of business, (ii) leases, sales or other dispositions of its assets that, together with all other assets of Borrower previously leased, sold or disposed of (other than disposed of pursuant to this Section 7.3(b)) during the twelve-month period ending with the month in which any such lease, sale or other disposition occurs, do not constitute a substantial portion of the assets of Borrower, (iii) sales of assets which are concurrently leased back, (iv) dispositions of assets which are obsolete or no longer used or useful in the business of Borrower, (v) as permitted pursuant to Section 14 or Section 15 (to the extent it applies to a merger pursuant to Section 14) of the Borrower Partnership Agreement, and (vi) the sale of membership interests in Bison Pipeline LLC pursuant to the Bison Pipeline Acquisition Agreement.

(c) Section 7.5 of the Credit Agreement is hereby amended by replacing such Section in its entirety with the following:

Section 7.5 Restricted Payments. The Borrower will not, and will not permit its Subsidiaries to, declare or make, or agree to pay or make, directly or indirectly, any dividend on any class of its stock, or make any payment on account of, or set apart assets for a sinking or other analogous fund for, the purchase, redemption, retirement, defeasance or other acquisition of, any shares of common stock or Indebtedness subordinated to the Obligations of the Borrower or any Guarantee thereof or any options, warrants, or other rights to purchase such common stock or such Indebtedness, whether now or hereafter outstanding (each, a "Restricted Payment"), except for (i) dividends payable by the Borrower solely in shares of any class of its common stock, (ii) Restricted Payments made by any Subsidiary to the Borrower or to another Subsidiary, on at least a pro rata basis with any other shareholders if such Subsidiary is not wholly owned by the Borrower and other wholly owned Subsidiaries, (iii) if no Event of Default has occurred or would result therefrom, distributions on the partnership interests in accordance with the Borrower Partnership Agreement and (iv) if no Event of Default has occurred or would result therefrom, distributions of proceeds from the Bison Pipeline Acquisition Agreement.

(d) Section 7.7 of the Credit Agreement is hereby amended by replacing such Section in its entirety with the following:

Section 7.7 Transactions with Affiliates. Except as set forth in Schedule 7.7, the Borrower will not, and will not permit any of its Subsidiaries to, sell, lease or otherwise transfer any property or assets to, or purchase, lease or otherwise acquire any property or assets from, or otherwise engage in any other transactions with, any of its Affiliates, except (a) in the ordinary course of business at prices and on terms and conditions not less favorable to the Borrower or such Subsidiary than could be obtained on an arm's-length basis from unrelated third parties, (b) any Restricted Payment permitted by Section 7.5 and (c) pursuant to the Bison Pipeline Acquisition Agreement.

2. **Conditions to Effectiveness of this Amendment.** Notwithstanding any other provision of this Amendment and without affecting in any manner the rights of the Lenders hereunder, it is understood and agreed that this Amendment shall not become effective, and the Borrower shall have no rights under this Amendment, until the Administrative Agent shall have received each of the following documents:

(a) executed counterparts to this Amendment from the Borrower, each of the Guarantors and the Lenders; and

(b) the indication of interest letter dated as of July 28, 2008 between the Borrower and TransCanada Pipeline USA Ltd. substantially setting out the terms of the Bison Pipeline Acquisition Agreement.

3. **Representations and Warranties.** To induce the Lenders and the Administrative Agent to enter into this Amendment, the Borrower hereby represents and warrants to the Lenders and the Administrative Agent:

(a) The Borrower, each of its Subsidiaries and the Operator (i) is duly organized, validly existing and in good standing as a corporation, partnership or limited liability company under the laws of the jurisdiction of its organization, (ii) has all requisite power and authority to carry on its business as now conducted, and (iii) is duly qualified to do business, and is in good standing, in each jurisdiction where such qualification is required, except where a failure to be so qualified could not reasonably be expected to result in a Material Adverse Effect.

(b) The execution, delivery and performance by the Borrower of the Loan Documents are within such Person's organizational powers and have been duly authorized by all necessary organizational, and if required, shareholder, partner or member, action;

(c) The execution, delivery and performance by the Borrower of this Agreement and the other Loan Documents (i) do not require any consent or approval of, registration or filing with, or any action by, any Governmental Authority, except those as have been obtained or made and are in full force and effect, (ii) will not violate any Requirements of Law applicable to the Borrower and any of its Subsidiaries, or any judgment, order or ruling of any Governmental Authority, (iii) will not violate or result in a default under any indenture, agreement or other instrument binding on the Borrower or any of its Subsidiaries or any of its assets or give rise to a right thereunder to require any payment to be made by the Borrower or any of its Subsidiaries, in each case other than violations, defaults or rights which could not reasonably be expected to result in a Material Adverse Effect, and (iv) will not result in the creation or imposition of any Lien on any asset of the Borrower or any of its Subsidiaries, except Liens (if any) created under the Loan Documents;

(d) This Amendment has been duly executed and delivered by the Borrower, and constitutes valid and binding obligations of the Borrower, enforceable against it in accordance with its terms, except as may be limited by applicable bankruptcy, insolvency, reorganization, moratorium, or similar laws affecting the enforcement of creditors' rights generally and by general principles of equity; and

(e) After giving effect to this Amendment, the representations and warranties contained in the Credit Agreement and the other Loan Documents are true and correct in all material respects, and no Default or Event of Default has occurred and is continuing as of the date hereof.

4. **Effect of Amendment.** Except as set forth expressly herein, all terms of the Credit Agreement, as amended hereby, and the other Loan Documents shall be and remain in full force and effect and shall constitute the legal, valid, binding and enforceable obligations of the Borrower to the Lenders and the Administrative Agent. The execution, delivery and effectiveness of this Amendment shall not, except as expressly provided herein, operate as a waiver of any right, power or remedy of the Lenders under the Credit Agreement, nor constitute a waiver of any provision of the Credit Agreement. This Amendment shall constitute a Loan Document for all purposes of the Credit Agreement.

5. **Governing Law.** This Amendment shall be governed by, and construed in accordance with, the internal laws of the State of New York and all applicable federal laws of the United States of America.

6. **No Novation.** This Amendment is not intended by the parties to be, and shall not be construed to be, a novation of the Credit Agreement or an accord and satisfaction in regard thereto.

7. **Costs and Expenses**. The Borrower agrees to pay on demand all costs and expenses of the Administrative Agent in connection with the preparation, execution and delivery of this Amendment, including, without limitation, the reasonable fees and out-of-pocket expenses of outside counsel for the Administrative Agent with respect thereto.

8. **Counterparts.** This Amendment may be executed by one or more of the parties hereto in any number of separate counterparts, each of which shall be deemed an original and all of which, taken together, shall be deemed to constitute one and the same instrument. Delivery of an executed counterpart of this Amendment by facsimile transmission or by electronic mail in pdf form shall be as effective as delivery of a manually executed counterpart hereof.

9. **Binding Nature.** This Amendment shall be binding upon and inure to the benefit of the parties hereto, their respective successors, successors-in-titles, and assigns.

10. **Entire Understanding.** This Amendment sets forth the entire understanding of the parties with respect to the matters set forth herein, and shall supersede any prior negotiations or agreements, whether written or oral, with respect thereto.

[*Signature Pages To Follow*]

IN WITNESS WHEREOF, the parties hereto have caused this Amendment to be duly executed, under seal in the case of the Borrower and the Guarantors, by their respective authorized officers as of the day and year first above written.

BORROWER:

NORTHERN BORDER PIPELINE COMPANY

By: TransCanada Northern Border Inc., its Operator

By /s/ Paul F. Miller
Name: Paul F. Miller
Title: Principal Executive Officer,Vice President and General Manager

By /s/ Patricia M. Wiederholt
Name: Patricia M. Wiederholt
Title: Principal Financial Officer and Controller

[SIGNATURE PAGE TO FIRST AMENDMENT]

LENDERS:

SUNTRUST BANK
as Administrative Agent, as Issuing Bank, as Swingline Lender and as a Lender

By /s/ Joe McCreery
Name: Joe McCreery
Title: Director

WACHOVIA BANK, NATIONAL ASSOCIATION
as Syndication Agent and as a Lender

By /s/ Lawrence P. Sullivan
Name: Lawrence P. Sullivan
Title: Managing Director

BMO CAPITAL MARKETS, as Co-Documentation Agent

By /s/ Ian M. Plester
Name: Ian M. Plester
Title: Director

BMO CAPITAL MARKETS FINANCING, INC., as a Lender

By /s/ Ian M. Plester
Name: Ian M. Plester
Title: Director

[SIGNATURE PAGE TO FIRST AMENDMENT]

CITIBANK, N.A., as Co-Documentation Agent and as a Lender

By /s/ Andrew L. Kreeger
Name: Andrew L. Kreeger
Title: Vice President

MIZUHO CORPORATE BANK, LTD., as Co-Documentation Agent and as a Lender

By /s/ Leon Mo
Name: Leon Mo
Title: Senior Vice President

JPMORGAN CHASE BANK, N.A., as Managing Agent and as a Lender

By /s/ Kenneth J. Fatur
Name: Kenneth J. Fatur
Title: Managing Director

EXPORT DEVELOPMENT CANADA, as Managing Agent and as a Lender

By /s/ Janine Dopson
Name: Janine Dopson
Title: Loan Asset Manager

By /s/ H. Clysdale
Name: Howard Clysdale
Title: Portfolio Manager

WELLS FARGO BANK N.A., **as a Lender**

By ________________________________
Name:
Title:

BANK OF AMERICA, N.A., **as a Lender**

By /s/ Jay Salitza
Name: Jay Salitza
Title: Vice President

ROYAL BANK OF CANADA, **as a Lender**

By ________________________________
Name:
Title:

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Section 4: EX-31.1 (CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER PURSUANT TO SECTION 302)

Exhibit 31.1

CERTIFICATION

I, Russell K. Girling, certify that:

1. I have reviewed this quarterly report on Form 10-Q for the quarter ended September 30, 2008 of TC PipeLines, LP;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluations; and

   d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation, of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Dated: November 3, 2008

/s/ Russell K. Girling
Russell K. Girling
Chairman, Chief Executive Officer and Director
TC PipeLines GP, Inc., as general partner of
TC PipeLines, LP (Principal Executive Officer)

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Section 5: EX-31.2 (CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER PURSUANT TO SECTION 302)

Exhibit 31.2

CERTIFICATION

I, Amy W. Leong, certify that:

1. I have reviewed this quarterly report on Form 10-Q for the quarter ended September 30, 2008 of TC PipeLines, LP;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluations; and

   d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation, of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Dated: November 3, 2008

/s/ Amy W. Leong
Amy W. Leong
Controller
TC PipeLines GP, Inc., as general partner of
TC PipeLines, LP (Principal Financial Officer)

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Section 6: EX-32.1 (CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER PURSUANT TO SECTION 906)

Exhibit 32.1

CERTIFICATION

I, Russell K. Girling, Chief Executive Officer of TC PipeLines GP, Inc., the general partner of TC PipeLines, LP (the Partnership), in compliance with 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 hereby certify, to the best of my knowledge**,** in connection with the Partnership's Quarterly Report on Form 10-Q for the period ended September 30, 2008 as filed with the Securities and Exchange Commission (the Report) on the date hereof, that:

- the Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
- the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

Dated: November 3, 2008

/s/ Russell K. Girling
Russell K. Girling
Chairman, Chief Executive Officer and Director
TC PipeLines GP, Inc., as general partner of
TC PipeLines, LP (Principal Executive Officer)

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Section 7: EX-32.2 (CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER PURSUANT TO SECTION 906)

Exhibit 32.2

CERTIFICATION

I, Amy W. Leong, Principal Financial Officer of TC PipeLines GP, Inc., the general partner of TC PipeLines, LP (the Partnership), in compliance with 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 hereby certify, to the best of my knowledge**,** in connection with the Partnership's Quarterly Report on Form 10-Q for the period ended September 30, 2008 as filed with the Securities and Exchange Commission (the Report) on the date hereof, that:

- the Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
- the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

Dated: November 3, 2008

/s/ Amy W. Leong
Amy W. Leong
Controller
TC PipeLines GP, Inc., as general partner of
TC PipeLines, LP (Principal Financial Officer)

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TCLP 10-K 12/31/2007

Section 1: 10-K (10-K)

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2007

or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Transition period from to

Commission File Number: 000-26091

TC PipeLines, LP

(Exact name of registrant as specified in its charter)

Delaware	**52-2135448**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)
13710 FNB Parkway Omaha, Nebraska	**68154-5200**
(Address of principal executive offices)	(Zip code)

877-290-2772
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:
None

Securities registered pursuant to Section 12(g) of the Act:
Common units representing limited partner interests

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerate filer", "accelerated filer" and "small reporting company" in Rule 12b-2 of the Exchange Act.
Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ Small Reporting Company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act).
Yes ☐ No ☒

Aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as at June 29, 2007 was approximately $953.5 million.

As of February 28, 2008, there were 34,856,086 of the registrant's common units outstanding.

TC PIPELINES, LP

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All amounts are stated in United States dollars unless otherwise indicated.

PART I

FORWARD-LOOKING STATEMENTS

The statements in this report that are not historical information, including statements concerning plans and objectives of management for future operations, economic performance or related assumptions, are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Exchange Act. Forward-looking statements may include words such as "anticipate," "estimate," "expect," "project," "intend," "plan," "believe," "forecast" and other words and terms of similar meaning. The absence of these words, however, does not mean that the statements are not forward-looking.

These statements reflect our current views with respect to future events, based on what we believe are reasonable assumptions. Certain factors that could cause actual results to differ materially from those contemplated in the forward-looking statements include:

- the ability of Great Lakes and Northern Border to continue to make distributions at their current levels;
- the impact of unsold capacity on Great Lakes and Northern Border being greater or less than expected;
- competitive conditions in our industry and the ability of our pipeline systems to market pipeline capacity on favorable terms, which is affected by:
  - future demand for and prices of natural gas;
  - competitive conditions in the overall natural gas and electricity markets;
  - availability of supplies of Canadian and U.S. natural gas;
  - availability of additional storage capacity;
  - weather conditions; and
  - competitive developments by Canadian and U.S. natural gas transmission companies;
- the Alberta (Canada) government's decision to implement a new royalty regime effective January 2009 may affect the amount of exploration and drilling in the Western Canada Sedimentary Basin;
- performance of contractual obligations by customers of our pipeline systems;
- operating hazards, natural disasters, weather-related delays, casualty losses and other matters beyond our control;
- the impact of current and future laws, rulings and governmental regulations, particularly FERC regulations, on us and our pipeline systems;
- our ability to control operating costs; and
- prevailing economic conditions, including conditions of the capital and equity markets and our ability to access these markets.

Other factors described elsewhere in this document, or factors that are unknown or unpredictable, could also have material adverse effects on future results. Please also read Item 1A. "Risk Factors." All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by these factors. These forward-looking statements and information is made only as of the date of the filing of this report, and except as required by applicable law, we undertake no obligation to update these forward-looking statements and information to reflect new information, subsequent events or otherwise.

Item 1. Business

OVERVIEW

We are a publicly traded Delaware limited partnership formed in 1998 by TransCanada PipeLines Limited, a wholly-owned subsidiary of TransCanada Corporation (collectively referred to as TransCanada), to acquire, own and participate in the management of United States (U.S.) based pipeline systems. We have broadened our initial scope to energy infrastructure assets in North America. To date, our primary focus has been in the transportation of natural gas from the Western Canada Sedimentary Basin (WCSB) to a variety of downstream markets.

TC PipeLines, LP and its subsidiary limited partnerships and subsidiary limited liability company, including, TC PipeLines Intermediate Limited Partnership (TC PipeLines ILP), TC Tuscarora Intermediate Limited Partnership (TC Tuscarora ILP), TC GL Intermediate Limited Partnership (TC GL ILP) and TC Pipelines Tuscarora LLC (TC Tuscarora LLC), are collectively referred to herein as "TC PipeLines" or "the Partnership." In this report, references to "we", "us" or "our" collectively refer to TC PipeLines or the Partnership. The general partner of the Partnership is TC PipeLines GP, Inc. (TC PipeLines GP), a wholly-owned subsidiary of TransCanada.

Our strategic focus is on delivering stable, sustainable cash distributions to our unitholders and finding opportunities to increase cash distributions while maintaining a low risk profile. Our current portfolio of pipeline investments in the U.S. consists of:

- A 100 per cent general partner interest in Tuscarora Gas Transmission Company (Tuscarora).
- A 46.45 per cent general partner interest in Great Lakes Gas Transmission Limited Partnership (Great Lakes). The remaining 53.55 per cent interest in Great Lakes is held by TransCanada.
- A 50 per cent general partner interest in Northern Border Pipeline Company (Northern Border). The other 50 per cent interest is held by ONEOK Partners, L.P. (ONEOK Partners), a publicly traded limited partnership that is controlled by ONEOK, Inc.

We account for our interests in both Great Lakes and Northern Border as equity investments; therefore, we do not consolidate their financial results. TransCanada operates Great Lakes, Northern Border and Tuscarora (collectively, "our pipeline systems"). See Item 13. "Certain Relationships and Related Transactions, and Director Independence".

Recent Developments

Tuscarora 100 per cent Ownership - On December 31, 2007, we purchased the remaining two per cent interest in Tuscarora, increasing our ownership interest to 100 per cent. One per cent was purchased from a wholly-owned subsidiary of TransCanada, while the other one per cent was purchased from Tuscarora Gas Pipeline Co., a wholly-owned subsidiary of Sierra Pacific Resources, for a combined purchase price of $3.9 million.

Northern Border Operatorship - On April 1, 2007, TransCanada Northern Border Inc. (TCNB), a wholly-owned subsidiary of TransCanada, became the operator of Northern Border, pursuant to an operating agreement entered into with Northern Border in April 2006.

Great Lakes Acquisition - On February 22, 2007, the Partnership acquired a 46.45 per cent general partner interest in Great Lakes from El Paso Corporation. The total purchase price was $942.4 million, subject to certain closing adjustments, and included the indirect assumption of approximately $209.0 million of debt. The acquisition was partially financed through a private placement of 17,356,086 common units at $34.57 per common unit for gross proceeds of $600.0 million which closed concurrently with the acquisition. TransCan Northern Ltd. (TransCan Northern), a wholly-owned subsidiary of TransCanada, purchased 8,678,045 of the 17,356,086 common units issued for gross proceeds of $300.0 million. In addition, TC PipeLines GP maintained its two per cent general partner interest in the Partnership by contributing $12.6 million to the Partnership in connection with the private placement.

The Partnership funded the balance of the total consideration with a draw on its senior credit facility, which was amended and restated in connection with this transaction. TransCanada, which previously held a 50 per cent interest in Great Lakes, acquired the remaining 3.55 per cent interest simultaneously with the Partnership's acquisition of its interest. A wholly-owned subsidiary of TransCanada also became the operator of Great Lakes.

Other Developments

Tuscarora Increased Ownership – On December 19, 2006, the Partnership acquired an additional 49 per cent general partnership interest in Tuscarora for approximately $99.8 million. In connection with this transaction, TCNB became the operator of Tuscarora.

Implementation of New Rates, Northern Border – In November 2006, the Federal Energy Regulatory Commission (FERC) approved the uncontested settlement of Northern Border's rate case. Beginning January 1, 2007, Northern Border's overall rates were reduced compared with rates prior to the filing, by approximately 5 per cent. The settlement also provided for seasonal rates for short-term transportation service.

Tuscarora Cost and Revenue Study – The Public Utilities Commission of Nevada (PUCN) approved Tuscarora's rate adjustment, which was subsequently approved by the FERC on July 3, 2006. The settlement resulted in a firm transportation rate of $0.40/decatherm per day (dth-day) beginning June 1, 2006, or a 17 per cent reduction to the previous rates of $0.481/dth-day.

Northern Border Increased Ownership – In April 2006, TC PipeLines purchased a 20 per cent partnership interest in Northern Border from ONEOK Partners. After the transaction, TC PipeLines and ONEOK Partners each own a 50 per cent interest in Northern Border.

Business Strategies

Our strategic focus is on delivering stable, sustainable cash distributions to our unitholders and finding opportunities to increase cash distributions while maintaining a low risk profile.

Our business strategies to achieve these objectives are to seek opportunities to undertake accretive acquisitions and organic growth projects, and maximize the value of our existing portfolio of pipeline systems. Working with our partners, if any, in our pipeline systems, we seek to pursue policies that:

- Maximize the utilization of our pipeline systems;
- Expand our pipeline systems to meet market demand; and
- Continue to promote safe and efficient operations.

In addition, we intend to support the execution of our business strategies by:

- Maintaining a strong and balanced financial position to:
    - maintain a prudent level of available cash for distribution to unitholders;
    - fund future growth; and
    - broaden our asset base in a disciplined and focused manner;
- Investing in North American energy infrastructure assets that are underpinned by strong business fundamentals and provide stable cash flows; and
- Maximizing the benefits of our relationship with TransCanada.

Competitive Strengths

We believe that we are well positioned to execute our business strategies successfully because of the following competitive strengths:

- Our pipeline systems hold strategic market positions and comprise critical transportation links for the transportation of natural gas from the Alberta Hub to U.S. markets. The Alberta Hub is one of the largest natural gas hubs in North America. Additional Canadian natural gas supply sources may be available in the future if new pipeline projects associated with the Mackenzie Delta in Northern Canada and Alaska are constructed;
- With TransCanada as operator of our pipeline systems, we believe they are well positioned to continue to operate as trusted and experienced transportation providers to our customers; and
- The senior management team and the board of directors of our general partner have extensive industry experience and include some of the most senior officers of TransCanada. The management team plays a significant role in developing the strategic direction of our pipeline systems and their associated operations, and we believe our ability to execute our business strategies is enhanced by our affiliation with TransCanada.

Our Relationship with TransCanada Corporation

One of our principal strengths is our relationship with TransCanada. TransCanada is a major North American energy infrastructure company with approximately 36,500 miles of wholly-owned natural gas pipelines, interests in an additional 4,800 miles of natural gas pipelines, approximately 360 billion cubic feet (Bcf) of storage capacity and, including facilities that are under construction or in development, also owns, operates, and/or controls approximately 7,700 megawatts of power generation. TransCanada, a Canadian corporation, was founded in 1951 with the objective of transporting natural gas from Alberta to distant markets. Today, TransCanada is engaged in numerous aspects of the energy industry but is primarily focused on natural gas transmission and power generation services.

TransCanada provides access to a significant pool of management talent and strong relationships throughout the energy industry. We expect to pursue strategic acquisitions in a disciplined manner and to have the opportunity to participate jointly with TransCanada in reviewing potential acquisitions, including transactions that we would be unable to pursue on our own. Additionally, we may have the opportunity to make acquisitions directly from TransCanada in the future. TransCanada, however, is under no obligation to allow us to participate in any of its pipeline or energy infrastructure acquisitions, nor is TransCanada required to offer any of its assets to us.

As of December 31, 2007, we had 34,856,086 common units outstanding, of which 24,142,935 were held by the public and 10,713,151 were held by wholly-owned subsidiaries of TransCanada. In addition, TransCanada owns the Partnership's general partner which holds a two per cent general partner interest in the Partnership. As such, TransCanada receives distributions as a common unitholder, distributions related to its two per cent general partner interest, as well as general partner incentive distributions if quarterly cash distributions on the common units exceed levels specified in the partnership agreement. See Item 5. "Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities".

Our Pipeline Systems

All of our pipeline systems are rate regulated by the FERC. Operating revenue is derived from the transportation of natural gas. The maximum transportation rates that our pipeline systems may charge are approved by the FERC, and in most cases, established in a FERC proceeding known as a rate case. During a rate case, a determination is reached by the FERC, either through a hearing or a settlement, on the maximum rates permissible for transportation service that include the recovery of cost-based investment, operating expenses and a reasonable return for its investors. Once maximum rates are set, the pipeline system is not permitted to adjust the maximum rates to reflect changes in costs or contract demand until new rates are approved by the FERC, usually after a rate case has been filed. Each pipeline system's tariff is approved by the FERC and specifies the maximum rates, as well as the general terms and conditions for natural gas transportation service on its pipeline. The tariff also allows for services to be provided under negotiated and discounted rates. As a result, earnings and cash flow of each pipeline system depend on costs incurred; contracted capacity and transportation path; the volume of gas transported; and the ability of each system to sell capacity at acceptable rates.

Our pipeline systems' transportation contracts include specifications regarding the receipt and delivery of natural gas at points along the pipeline system. The type of transportation contract, either for firm or interruptible service, determines the basis upon which each customer is charged. Customers with firm service transportation agreements pay a fee known as a reservation charge to reserve pipeline capacity, regardless of use, for the term of their contracts. On the Great Lakes and Northern Border systems, firm service transportation customers also pay a variable usage fee known as a commodity charge or utilization fee that is based on distance and the volume of natural gas they transport. Transportation customers on the Northern Border system also pay a compressor usage surcharge, effective with the settlement of the 2005 rate case, resulting in new rates which were implemented January 1, 2007. Customers with interruptible service transportation agreements may utilize available capacity on a pipeline system after firm service transportation requests are satisfied. Interruptible service customers are assessed commodity charges (or utilization fees) based on distance and the volume of natural gas they transport. The table below provides information with respect to tariff revenue composition for each of our investments for the year ended December 31, 2007. The weighted average remaining contract life is determined as at January 31, 2008.

		Tariff Revenue Composition			
		Firm Contracts		Interruptible	
	Our Ownership Interest	Capacity Reservation Charges	Variable Usage Fees (1)	Contracts & Other Services	Weighted Average Remaining Contract Life (in years) (2)
Great Lakes	46.45%	97%	3%	0%	2.4
Northern Border	50%	91%	7%	2%	1.3
Tuscarora	100%	100%	n/a	0%	10.4

(1) Variable usage fees for Northern Border include a compressor usage surcharge which relate to both, firm and interruptible contracts. Tuscarora does not have any variable usage fees as part of their tariff.

(2) Weighted average remaining contract life is weighted based upon maximum daily quantity (MDQ) in the contracts.

The table below provides information on the average throughput of our pipeline systems:

Average Throughput (MMcf/d)	2007	2006	2005
Great Lakes (1)	2,270	2,236	2,360
Northern Border	2,247	2,246	2,277
Tuscarora	77	77	69

(1) The average throughput for Great Lakes includes periods prior to the February 22, 2007 acquisition by us of a 46.45 per cent general partner interest in Great Lakes.

Business of Great Lakes

Great Lakes is a Delaware limited partnership formed in 1990 and holds the assets formerly held by Great Lakes Transmission Company. The FERC certificate to construct its initial facilities was issued in 1967. Great Lakes is owned 46.45 per cent by us, with the remainder owned by TransCanada. Additionally, Great Lakes is operated by TransCanada.

The major policies of Great Lakes are established by the management committee of Great Lakes (GL Management Committee), which consists of up to six members, three of whom are designated by us and three of whom are designated by TransCanada. The GL Management Committee consists of four appointed members, two of whom are designated by us and two of whom are designated by TransCanada. All decisions by the GL Management Committee require unanimous consent. For the day to day management of Great Lakes' business, the GL Management Committee established an executive committee, which consists of up to three members: one Partnership GL Management Committee Member, one TransCanada GL Management Committee Member and the president of Great Lakes, who is a non-voting member (GL Executive Committee). The GL Executive Committee currently consists of two appointed members: one Partnership GL Management Committee member, and one TransCanada GL Management Committee member, who also serves as the president of Great Lakes. The GL Executive Committee has all of the powers of the GL Management Committee in the management of Great Lakes' business.

Great Lakes was originally constructed as an operational loop of the TransCanada Mainline Northern Ontario system. Great Lakes receives natural gas from TransCanada at the Canadian border near Emerson, Manitoba. Great Lakes' pipeline system extends across Minnesota, Northern Wisconsin and Michigan, and redelivers gas to TransCanada at the Canadian border at Sault Ste. Marie, Michigan and St. Clair, Michigan.

The Great Lakes mainline transmission pipeline has diameters ranging from 10 inches to 36 inches. The Great Lakes system consists of approximately 2,115 miles of pipeline with a design capacity of 2.3 Bcf per day at the Emerson Inlet. Great Lakes has 14 compressor stations with a total of 438,000 horsepower and measurement facilities to support the 55 receipt and delivery points for gas.

The original construction of Great Lakes' system occurred in 1967 and 1968. There have been numerous capacity system expansions since its original construction, the last one completed in 1998.

Business of Northern Border

Northern Border is a Texas general partnership formed in 1978. TC PipeLines, through its subsidiary TC PipeLines ILP, and ONEOK Partners, through its subsidiary ONEOK Partners Intermediate Limited Partnership, each own a 50 per cent interest in Northern Border.

Northern Border is managed by a management committee that consists of four members. Each partner designates two members, and we designate one of our members as Chairman. Each partner holds a 50 per cent voting interest on the management committee.

Northern Border extends from the Canadian border near Port of Morgan, Montana to a terminus near North Hayden, Indiana. Northern Border's transportation system provides pipeline access to the Midwestern U.S. from natural gas reserves in the WCSB. Additionally, Northern Border transports natural gas produced in the Williston Basin of Montana and North Dakota and the Powder River Basin of Wyoming and Montana and synthetic gas produced at the Dakota Gasification plant in North Dakota.

The pipeline system consists of 1,249 miles of pipeline with diameters ranging from 30 to 42 inches and a design capacity on the largest segment of the pipeline of 2,374 MMcf/d. Along the pipeline are 17 compressor stations with a total of 515,000 horsepower, measurement facilities to support the receipt and delivery of gas at ten receipt and 50 delivery points, four field offices and a microwave communication system with 50 tower sites.

Construction of Northern Border's system was initially completed in 1982, followed by expansions or extensions in 1991, 1992, 1998, 2001 and 2006.

Des Plaines Project – In February 2008, Northern Border filed with the FERC to construct, own and operate interconnect facilities, including a 1,600 horsepower compressor facility near Joliet, Illinois. It is estimated that this project will cost approximately $17 million. The targeted in-service date included in Northern Border's FERC certificate application is November 1, 2008; however, this schedule is dependent upon the receipt of timely regulatory approvals. The Des Plaines Project will be fully subscribed under long-term compression and transportation contracts, per the executed precedent agreement.

Business of Tuscarora

Tuscarora is a Nevada general partnership formed in 1993. We own 100 per cent of Tuscarora through two subsidiaries: TC Tuscarora ILP owns a 99 per cent general partner interest in Tuscarora, with TC Pipelines Tuscarora LLC owning the remaining one per cent general partner interest.

The Tuscarora system originates at an interconnection point with existing facilities of Gas Transmission Northwest Corporation (GTN), a wholly-owned subsidiary of TransCanada, near Malin, Oregon and runs Southeast through Northeastern California and Northwestern Nevada. The Tuscarora pipeline system terminates near Wadsworth, Nevada. Along its route, deliveries are made in Oregon, Northern California and Northwestern Nevada.

Tuscarora owns a 240-mile, 20-inch diameter, pipeline system with a design capacity of approximately 190 MMcf/d. Tuscarora has two compressor stations with a total of 11,400 horsepower, and measurement facilities at one receipt point and 16 delivery points.

The Tuscarora pipeline system was initially placed into service in 1995. Expansions or extensions were completed in 2001, 2002 and 2005.

2008 Expansion Project - In July 2007, Tuscarora received FERC approval for the construction of a compressor station and related facilities (Tuscarora 2008 Expansion Project). This approximately $20 million project is underpinned by a 22.5 year long-term contract to transport a maximum of 39 MMcf/d to Sierra Pacific Power Company (Sierra Pacific Power), a subsidiary of Sierra Pacific Resources, to supply its Tracy Combined Cycle Power Plant. The project is expected to be in service in March 2008.

NATURAL GAS INDUSTRY OVERVIEW

North American Demand

Over the last fifteen years, natural gas demand in North America has increased by approximately 15 Bcf/d. Demand for natural gas is expected to continue to grow across North America in 2008 and beyond. Demand for natural gas transportation service on a pipeline system is directly related to demand for natural gas in the markets served by that system. Factors that may impact demand for natural gas include:

- weather conditions;
- economic conditions;
- government regulation;
- the availability and price of alternative energy sources versus natural gas;
- natural gas storage inventories for the markets served;
- fuel conservation measures; and
- technological advances in fuel economy and energy generation devices.

Furthermore, factors that may impact demand for natural gas transportation service on any one system include:

- availability of natural gas supply at the pipeline system's receipt points;
- the ability and willingness of natural gas shippers to utilize the pipeline system over alternative pipelines;
- relative transportation rates; and
- the volume of natural gas delivered to markets from other supply sources and storage facilities.

The primary exposure to business risk for our pipeline systems occurs when our pipeline systems are marketing their available capacity, such as when existing transportation contracts expire and are subject to renegotiation. Customers with competitive alternatives analyze the market price spread or basis differential between receipt and delivery points along the pipeline to determine their expected gross margin. The anticipated margin and its variability are important determinants of the transportation rate customers are willing to pay. The customers on our pipelines include local distribution companies (LDCs), industrial companies, electric generation companies, natural gas producers, other natural gas pipelines and natural gas marketing and trading companies.

Our Pipeline Systems

Demand for transportation on Great Lakes has remained relatively constant over the last five years from LDCs and industrial customers, as well as for transportation of volumes back into Canada. Great Lakes' customer profile is becoming more heavily weighted towards natural gas marketing and trading companies and less towards producers and end users, such as industrial customers and LDCs.

Northern Border's contract life has been declining with a customer profile over the past five years mainly comprised of producers and natural gas marketing and trading companies. Northern Border delivers gas to highly competitive markets including interconnections with other major interstate natural gas pipelines and major market centers that serve winter heating and summer cooling demand, industrial load and storage areas to replenish inventory.

Demand on Tuscarora has steadily increased over the last several years due to increased demand from electric generation companies and LDCs.

Seasonality

North America

North American demand for natural gas is seasonal. In general, demand tends to be higher in the winter months for heating requirements and in the summer for power generation demand in support of cooling requirements. This effect can be somewhat mitigated in the spring and fall by the need for industries to replenish the amount of gas held in storage for future use.

The amount of uncontracted transportation capacity as well as transportation capacity under short term contracts on a pipeline system determines the extent that seasonal demand will impact a pipeline system's revenue. Pipeline systems that have a higher ratio of long-term contracts (contracts with a duration longer than one year) will be impacted less by seasonal demand. Conversely, for those pipeline systems with more available capacity, or operating under short term contracts, fluctuations in demand between seasons can impact revenue. Pipeline systems which have a tariff that includes seasonal rates for short term service may be able to mitigate the potential negative impact of seasonal fluctuations in demand.

Great Lakes - As a turbine based pipeline system, Great Lakes' design day capacity at the Emerson inlet is approximately 2.45 Bcf/day during the winter and 2.3 Bcf/day during the summer (system fuel requirements utilize a portion of this capacity). Though the winter flow capability is higher than the summer capability, the market demand for Great Lakes' long haul service can be higher in the summer when Great Lakes' system has less transportation capacity.

The demand for Great Lakes' long haul service is at its highest when natural gas is being delivered to natural gas storage areas. This is due to the approximate 880 Bcf of working gas storage located at the end of the Great Lakes system in Michigan and Ontario. The high demand period usually begins in the spring and extends through most of the summer. The transportation value across the Great Lakes pipeline system is at its highest in conjunction with storage fill requirements and electric power generation demand.

During the winter, there is also strong demand for Great Lakes services to meet the peak winter demand requirements of Northern Minnesota, Northern Wisconsin, and Michigan. These deliveries are met through Great Lakes short haul, long haul, and backhauls from storage. In fact, the aggregated peak day of all short haul and long haul flows occurs during the winter. Approximately ten per cent of Great Lakes' flows were contracted on a short-term basis in 2007.

Great Lakes experiences significant winter volatility in the utilization of its long haul contracts due to downstream constraints on the Union Gas Limited and TransCanada systems. As the demand for storage withdrawals from the Dawn, Ontario storage facility increases to serve points east, so does the level of downstream constraints which may reduce shippers' ability to use Great Lakes' transportation services to serve Eastern markets. This constraint may reduce demand for Great Lakes' capacity during certain winter periods.

Northern Border - Seasonal supply and demand fundamentals are a growing influence on Northern Border's system throughput due to increased competition for WCSB supply and growing competition from alternate sources of supply, such as the Rockies, in the markets served by Northern Border. Demand for Northern Border's transportation has traditionally been the strongest during peak winter months to serve heating demand and peak summer months to serve electric cooling demand and storage injection. Demand conditions in other market regions for Canadian supply can impact the transportation value of Northern Border's system. For example, the Western U.S. market is sensitive to precipitation levels, which impact hydroelectric power generation. During the summer, high temperatures combined with low hydroelectric power generation levels can increase demand for Canadian natural gas in this region and shift supply away from Northern Border's system.

Northern Border's rate case settlement established seasonal rates for short-term service of less than one year that provide for higher maximum rates during anticipated peak usage periods and lower maximum rates during anticipated periods of reduced demand. Approximately 34 per cent of Northern Border's design capacity was contracted on a short-term basis in 2007.

Tuscarora **-** Tuscarora is almost fully contracted under long-term contracts (approximately 97 per cent contracted with a weighted average remaining contract life of 10.4 years) at December 31, 2007. As a result, fluctuations in revenue due to seasonality are minimal.

Supply

North American Supply

The primary source of natural gas transported by all of our pipeline systems is the WCSB. For this reason, the continuous supply of Canadian natural gas is crucial to the long-term financial condition of our pipeline systems.

As of December 2006, the WCSB had remaining discovered natural gas reserves of approximately 57 trillion cubic feet and a reserves-to-production ratio of approximately nine years at current levels of production. Historically, additional reserves have continually been discovered to maintain the reserves-to-production ratio at close to nine years. It is expected that producers will continue to explore and develop new fields, particularly in the Northeastern and West central foothills regions of Alberta, Canada. There will also be significant activity aimed at unconventional resources such as coal bed methane.

The amount of WCSB natural gas available for export is the most significant factor affecting the volume of natural gas transported by our pipeline systems. The amount of WCSB natural gas available for export is determined by:

- WCSB natural gas production levels;
- demand for WCSB natural gas; and
- storage capacity for WCSB natural gas and demand for storage injection.

The extent to which WCSB natural gas available for export will be transported on each pipeline system is affected by:

- demand for WCSB natural gas in different U.S. consumer markets;
- available transportation capacity and related market pricing options on our competitors' pipelines;
- natural gas from other supply sources that can be transported to our customer markets;
- the natural gas market price spread between Alberta, Canada and the applicable market which reflects the relative supply and demand for WCSB natural gas in Canada and in the U.S.; and
- storage capacity in the U.S. and Canada and the related demand for storage injection.

Our Pipeline Systems

In 2007, approximately 84 per cent, 82 per cent and 92 per cent of the natural gas transported by Great Lakes, Northern Border and Tuscarora, respectively, was produced in Canada.

Great Lakes receives natural gas from interconnections with the TransCanada Mainline, ANR and from storage facilities. Gas received from the interconnection with the TransCanada Mainline at Emerson, Manitoba is WCSB supply. ANR is connected with numerous other pipelines, sourcing gas from virtually all North American basins as well as imported LNG.

Northern Border is also connected directly with other natural gas supplies. Natural gas produced in the Williston Basin of Montana and North Dakota and the Powder River Basin of Wyoming and Montana accounted for approximately 12 per cent of the natural gas Northern Border transported in 2007. The remaining natural gas transported by Northern Border was synthetic gas produced at the Dakota Gasification plant in North Dakota.

Tuscarora receives natural gas from its interconnection with GTN. GTN is interconnected with WCSB supply as well as natural gas from the Rockies and other U.S. basins.

CUSTOMERS, COMPETITION AND CONTRACTING

Customers

Great Lakes - The largest customer for Great Lakes' capacity is TransCanada, through its mainline pipeline system. This capacity is used by TransCanada customers to transport Western Canadian gas to Eastern Canadian and U.S. markets. ANR also holds capacity on Great Lakes to integrate its Michigan storage locations with its Wisconsin pipeline system. Various local distribution companies in Minnesota, Wisconsin and Michigan contract for transportation on Great Lakes to add Canadian gas to their supply mix. In addition, natural gas marketing and trading companies and producers hold transportation capacity on Great Lakes, either directly or through the capacity release program, and use Great Lakes' flexibility to deliver gas to markets, interconnecting pipelines and storage facilities along its system to maximize the value of their transportation contracts.

For the year ended December 31, 2007, TransCanada and ANR contracts represented approximately 45 per cent and three per cent, respectively, of Great Lakes' revenue. Great Lakes did not have any other customers contributing more than 10 per cent of their 2007 revenues.

Although Great Lakes has traditionally operated under long-term contracts, in response to changing market conditions, it markets its capacity on a shorter-term basis to a wide variety of customers, including producers, natural gas marketing and trading companies and LDCs in the U.S. and Canada.

Northern Border - Northern Border serves Midwestern U.S. markets for customers located throughout North America. Northern Border's customers include natural gas producers, marketing and trading companies, industrial facilities, local distribution companies and electric power generating plants.

For the year ended December 31, 2007, contracts with BP Canada Energy Marketing Corp., Nexen Marketing, U.S.A., Inc. and Cargill Inc. represented approximately 16 per cent, 14 per cent and 14 per cent, respectively, of Northern Border's revenue.

Tuscarora - Tuscarora serves markets in Oregon, Northern California and Northern Nevada. Deliveries are also made directly to the local gas distribution system of Sierra Pacific Power. Tuscarora's customers include power generation companies, local distribution companies, and a variety of industrial, commercial, and other companies.

For the year ended December 31, 2007, contracts with Sierra Pacific Power, Southwest Gas Company and Barrick Goldstrike Mines represented approximately 72 per cent, 13 per cent and 11 per cent, respectively, of Tuscarora's revenue.

Competition

Competition among natural gas pipelines is based primarily on transportation charges and proximity to natural gas supply areas and markets. Our pipeline systems face competition at both the supply and market ends of their pipeline systems where other pipelines access the same supply basins and/or deliver to markets served by our respective pipelines. Other pipelines access the WCSB supply basin and provide alternative routes for shippers to access markets served by our systems. Additionally, other pipelines bring supply sourced from other U.S. supply basins into our market areas.

Great Lakes - Great Lakes' principal business comes from its position as a link in the chain of pipelines that facilitate the transportation of natural gas from Western Canada to Eastern Canadian markets. Natural gas is transported by TransCanada from Western Canada to near Emerson, Manitoba, from Emerson to St. Clair, Michigan by Great Lakes, and from St. Clair to Dawn, Ontario and points further east by TransCanada. The primary competition for Great Lakes is the alternate route from Western Canada to Dawn on TransCanada's Mainline. Other routes from Western Canada to Ontario, Canada, are the Foothills Pipeline to Northern Border to Vector Pipeline route and the Alliance Pipeline to Vector Pipeline route. In addition, gas sourced from the U.S. Rockies, U.S. Mid-Continent and U.S. Gulf Coast can be delivered to Chicago and then to Ontario via the Vector Pipeline.

Northern Border - Northern Border's system competes for natural gas supply with other pipelines that transport Western Canadian natural gas to markets in the West, Midwest and East in North America, including TransCanada and Alliance Pipeline. Northern Border also competes for demand for transportation services with other pipelines that provide the markets it serves with access to natural gas storage facilities, and with alternate sources of supply, such as the Rockies, the Mid-Continent, the Permian Basin and the Gulf Coast, and LNG. A new competitor is the REX-West segment of the 1,679 mile Rockies Express Pipeline system from Rio Blanco County, Colorado to Monroe County, Ohio, which is increasing supply competition in Midwestern markets and could cause Northern Border to discount their rates or otherwise experience a reduction in their revenues.

Tuscarora - Shippers of natural gas from the WCSB have other options for transporting Canadian natural gas to markets throughout Canada and the U.S.

Tuscarora's primary competition in the Northern Nevada natural gas transmission market is with Paiute Pipeline Company (Paiute), owned by Southwest Gas Co. of Las Vegas, Nevada. Paiute interconnects with Northwest Pipeline Corp. at the Nevada-Idaho border and transports natural gas from British Columbia and the U.S. Rocky Mountain Basin to the Northern Nevada market.

Contracting

As existing contracts on our pipeline systems approach their expiration dates, efforts are made to extend and/or renew the contracts. The ability to extend and/or renew expiring contracts will depend upon competitive alternatives, the regulatory environment, and market and supply factors. The duration of new or renegotiated contracts will be affected by current market price spreads, transportation rates, competitive conditions, and judgments concerning future market trends and volatility. If market conditions are not favorable at the time of renewal, then transportation capacity may be uncontracted until market conditions become more favorable. Subject to regulatory requirements, our pipeline systems attempt to recontract or remarket their capacity at the maximum rates allowed under their tariffs. However, a pipeline system may discount capacity under certain circumstances in order to maximize revenue.

Great Lakes - Existing transportation contracts mature at varying times and in varying amounts of throughput capacity. Approximately four per cent of Great Lakes' contracted capacity expired in 2007 and 15 per cent will expire by December 31, 2008 in the absence of extensions or renewals of this capacity. In addition, ANR holds over 1,100 Mdth/d of capacity on Great Lakes that is expected to be renewed annually. For the year ended December 31, 2007, Great Lakes' average contracted capacity compared was 106 per cent.

Northern Border - Northern Border contracted 97 per cent of its design capacity on a firm basis in 2007, some of which was sold at a discount to maximize overall revenue on the Port of Morgan, Montana to Harper, Iowa portion of the pipeline. As of January 31, 2008, Northern Border had 37 per cent of its design capacity uncontracted beginning in the second quarter of 2008 and 48 per cent uncontracted by the end of 2008. Refer to Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" for further discussion.

Tuscarora **–** Tuscarora's average contracted capacity for the year ended December 31, 2007 was 96 per cent. Tuscarora has firm transportation contracts for 97 per cent of its available contracted capacity, as at January 31, 2008. This includes contracts held by Sierra Pacific Power for 69 per cent of the total available capacity, the majority of which expire on October 31, 2017.

REGULATORY ENVIRONMENT

Government Regulation

Great Lakes, Northern Border, and Tuscarora are regulated under the Natural Gas Act of 1938, Natural Gas Policy Act of 1978, and Energy Policy Act of 2005, which give the FERC jurisdiction to regulate virtually all aspects of their business, including:

- transportation of natural gas;
- rates and charges;
- terms of service and service contracts with customers, including creditworthiness requirements;
- certification and construction of new facilities;
- extension or abandonment of service and facilities;
- accounts and records;
- depreciation and amortization policies;
- the acquisition and disposition of facilities;
- initiation and discontinuation of services; and

- standards of conduct for business relations with certain affiliates.

Rate Case, Great Lakes – Great Lakes' last rate settlement expired on October 31, 2005 with no requirement to file a new rate proceeding or settlement.

Rate Case, Northern Border - In November 2006, the FERC approved the settlement with Northern Border's customers of its 2005 rate case to be effective January 1, 2007. The settlement established maximum long-term mileage-based rates and charges for transportation on Northern Border's system. Northern Border's overall rates were reduced, compared with rates prior to the filing, by approximately 5 per cent. The settlement also provided for seasonal rates for short-term transportation services. The settlement included a three-year moratorium on filing rate cases and participants challenging Northern Border's rates and requires that Northern Border file a rate case within six years from the date the new rates went into effect.

Cost and Revenue Study, Tuscarora - As a result of an obligation to file a cost and revenue study with the FERC pursuant to an agreement with the PUCN, Tuscarora, Sierra Pacific Power and the PUCN entered into settlement discussions with respect to a potential rate adjustment in 2006. In April 2006, the PUCN and Sierra Pacific Power agreed to a settlement with Tuscarora, which was subsequently approved by the FERC in July 2006. The settlement resulted in a firm transportation rate of $0.40/decatherm per day (dth-day) beginning June 1, 2006, or a 17 per cent reduction to the previous rate of $0.481/dth-day. The settlement also included a moratorium on all rate actions before the FERC by any party to the settlement until May 31, 2010, including rate actions related to expansion projects where Tuscarora proposes to price the expansion at the settlement rate.

Income Tax Allowance – In May 2005, the FERC issued a policy statement permitting the inclusion of an income tax allowance in the rates for partnership interests held by partners with an actual or potential income tax liability. On December 16, 2005, the FERC issued an order (the "December 16 Order") in its first case-specific review of the income tax allowance issue, reaffirming its tax allowance policy and directing the pipeline to provide certain evidence necessary to determine the income tax allowance. The FERC's new policy and the December 16 Order were appealed; however, the United States Court of Appeals for the D.C. Circuit subsequently denied the petitions for review and upheld the FERC's income tax allowance policy.

On December 26, 2007, the FERC issued an order (the "December 26 Order") which upheld and clarified its methodology for determining a partnership's income tax allowance in a rate case. In the future, partnerships will be required to prove (1) that its partners have an actual or potential income tax liability, which is determined by the partner's obligation to file a return that recognizes either a taxable gain or loss; (2) its partners' marginal Federal income tax rates, if higher than the commission's default rates of 28 per cent for individuals and 34 per cent for corporations, and (3) the partners' marginal state income tax rates. If the FERC were to disallow a portion of the income tax allowance for one of our pipeline systems in a rate case, it may cause its recourse rate to be set at a level that is different, or lower, than the level otherwise in effect.

Composition of Proxy Groups for Rates of Return Determinations - On July 19, 2007, the FERC issued a policy statement proposing to update its standards regarding the composition of proxy groups for determining the appropriate returns on equity for natural gas and oil pipelines. The proposed policy statement would permit the inclusion of master limited partnerships (MLPs) in the proxy group for purposes of calculating returns on equity under the Discounted Cash Flow (DCF) analysis. This is a change from its prior view that MLPs should not be included in the proxy group. Specifically, the FERC proposes that MLPs may be included in the proxy group provided that the distributions used in the DCF analysis are capped at the pipeline's reported earnings level. According to the proposed policy statement, the return on equity under the DCF analysis is calculated by adding the dividend or distribution yield (dividends divided by share/unit price) to the projected future growth rate of dividends or distributions. The future growth rate is weighted based on the long-term growth of the economy and the short-term growth for the pipeline. Additionally, the decision as to whether an MLP is included in the proxy group will be made on a case by case basis and will be based on stability of the MLP's earnings over a number of years. The FERC is currently evaluating the merit of the new policy statement through comments, reply comments and technical conferences. The FERC's proposed policy statement is subject to change based on comments filed and the outcome of the technical conference and therefore we cannot predict the impact or timing of the final policy statement.

Energy Affiliates – In November 2003, the FERC adopted revised standards of conduct which govern the relationships between regulated interstate natural gas pipelines and their energy affiliates. The new standards of conduct were designed to prevent interstate natural gas pipelines from giving any undue preference to their energy affiliates and ensure that transmission service is provided on a nondiscriminatory basis. In November 2006, the United States Court of Appeals for the District of Columbia vacated the FERC's order regarding standards of conduct for energy affiliates of natural gas pipelines and remanded the matter back to the FERC. On January 9, 2007, the FERC issued Order No. 690, Standards of Conduct for Transmission Providers (the Interim Rule) as the Commission's interim response to the Appeals Court decision. The Interim Rule reduced the application of the standards of conduct for interstate natural gas pipelines to the relationship between the pipelines and their marketing affiliates as defined in the FERC's rules that were in effect prior to the current regulations and made certain other revisions that were subject to the appeal. Requests for clarifications and in the alternative rehearing of the Interim Rule have been filed. On January 18, 2007, the FERC issued a Notice of Proposed Rulemaking, which if accepted as the final rule, will make permanent the Interim Rule's applicability of the standards of conduct to govern the relationship between interstate natural gas pipelines and their marketing affiliates.

Market Manipulation – In January 2006, the FERC issued a final rule making it unlawful for any entity subject to its jurisdiction that directly or indirectly purchases or sells natural gas, transportation services or electric energy to defraud, using any device, scheme or artifice; make untrue statements of a material fact or omit a material fact; or engage in any act, practice or course of business that operates as a fraud. The maximum civil penalty under these statutes is $1 million per day, per violation.

Environmental and Safety Matters

All of our pipeline systems' operations are subject to stringent and complex federal, state, and local laws and regulations governing environmental protection, including air emissions, water quality, wastewater discharges, and solid waste management. Such laws and regulations generally require natural gas pipelines to obtain and comply with a wide variety of environmental registrations, licenses, permits, and other approvals. These laws and regulations also can restrict or impact business activities in many ways, such as restricting the way wastes are handled or disposed of; requiring remedial action to mitigate pollution conditions that may be caused by its operations or that are attributable to former operators; and enjoining some or all of the operations of facilities deemed in non-compliance with permits issued pursuant to such environmental laws and regulations. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and/or criminal penalties, the imposition of remedial requirements, and the issuance of orders enjoining future operations.

Pipeline Safety – Our pipeline systems are subject to U.S. Department of Transportation pipeline integrity management regulations. The Pipeline Safety Improvement Act requires pipeline companies to perform integrity assessments on pipeline segments that exist in densely populated areas or near specifically identified sites that are designated as high consequence areas. Pipeline companies are required to perform the integrity assessments within ten years of the date of enactment and perform subsequent integrity assessments on a seven-year cycle. All of our pipeline systems had performed the required assessments of 50 per cent of the highest priority high consequence areas by the end of 2007.

Waste Management – The operations of our pipeline systems generate hazardous and non-hazardous solid wastes that are subject to the federal Resource Conservation and Recovery Act (RCRA) and comparable state laws, which impose detailed requirements for the handling, storage, treatment and disposal of hazardous and non-hazardous solid wastes. For instance, RCRA prohibits the disposal of certain hazardous wastes on land without prior treatment, and requires generators of wastes subject to land disposal restrictions to provide notification of pre-treatment requirements to disposal facilities that are in receipt of these wastes. Generators of hazardous wastes also must comply with certain standards for the accumulation and storage of hazardous wastes, as well as with recordkeeping and reporting requirements applicable to hazardous waste storage and disposal activities.

Site Remediation - The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), also known as "Superfund," and comparable state laws and regulations impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons considered to be responsible for the release of hazardous substances into the environment. These persons include the current and past owner or operator of the site where the release occurred, and anyone who disposed or arranged for the disposal of a hazardous substance released

at the site. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies.

Our pipeline systems currently own or lease properties that for many years have been used for the transportation and compression of natural gas. These properties and the substances released on them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, our pipeline systems could be required to remove any previously disposed wastes, including waste disposed of by prior owners or operators; remediate contaminated property, including groundwater contamination, whether from prior owners or operators or other historic activities or spills; or perform remedial closure operations to prevent future contamination.

Air Emissions - The Clean Air Act (CAA) and comparable state laws regulate emissions of air pollutants from various industrial sources, including compressor stations, and also impose various monitoring and reporting requirements. Such laws and regulations may require pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in an increase of existing air emissions; application for, and strict compliance with, air permits containing various emissions and operational limitations; or the utilization of specific emission control technologies to limit emissions.

Water Discharges - The Clean Water Act (CWA) and analogous state laws impose strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the Environmental Protection Agency (EPA) or an analogous state agency. The CWA and regulations implemented thereunder also prohibit the discharge of dredge and fill material into regulated waters, including wetlands, unless authorized by an appropriately issued permit. Federal and state regulatory agencies may impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the CWA and analogous state laws and regulations.

Activities on Federal Lands - Natural gas transportation activities are subject to the National Environmental Policy Act (NEPA). NEPA requires federal agencies, including the Department of the Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. The current activities of our pipeline systems, as well as any proposed plans for future activities, on federal lands are subject to the requirements of NEPA.

Other Laws and Regulations - Recent scientific studies have suggested that emissions of certain gases, commonly referred to as “greenhouse gases” and including carbon dioxide and methane, may be contributing to warming of the Earth’s atmosphere. In response to such studies, the U.S. Congress is actively considering legislation to reduce emissions of greenhouse gases. In addition, several states have declined to wait on Congress to develop and implement climate control legislation and have already taken legal measures to reduce emissions of greenhouse gases.

The Department of Homeland Security Appropriations Act of 2007 requires the Department of Homeland Security (DHS) to issue regulations establishing risk-based performance standards for the security of chemical and industrial facilities, including oil and gas facilities that are deemed to present “high levels of security risk.” The DHS is currently in the process of adopting regulations that will determine whether some of our pipeline facilities or operations will be subject to additional DHS-mandated security requirements.

Title to Properties

Our pipeline systems hold all rights, titles and interests in their pipeline system. With respect to real property, our pipeline systems own sites for compressor stations, meter stations, pipeline field offices, microwave towers and a corporate office. Our pipeline systems also derive interests from leases, easements, rights-of-way, permits and licenses from landowners or governmental authorities permitting land use for construction and operation of their pipelines.

Great Lakes - Approximately 74 miles of Great Lakes’ pipeline system are located within the boundaries of three Indian reservations: the Leech Lake Chippewa Indian Reservation and the Fond du Lac Chippewa Indian Reservation in Minnesota, and Bad River Chippewa Indian Reservation in Wisconsin. In 1968, Great Lakes obtained right-of-way across allotted lands located within each of the reservations boundaries. All of the allotted lands are subject to a 50 year easement granted by the Bureau of Indian Affairs (BIA) for and on behalf of the individual Indian owners or the reservations. These tracts are subject to right-of-way permits issued by the BIA that expire in 2018. Also, the Great Lakes pipeline crosses approximately 1000 ft. in two tracts in Lower Michigan, which are located within the Chippewa Indian Reservation, under perpetual easements.

Northern Border - Approximately 90 miles of Northern Border’s pipeline system are located within the boundaries of the Fort Peck Indian Reservation in Montana. In 1980, Northern Border entered into a pipeline right-of-way lease with the Fort Peck Tribal Executive Board on behalf of the Assiniboine and Sioux Tribes of the Fort Peck Indian Reservation. This pipeline right-of-way lease granted Northern Border the right to construct and operate its pipeline on certain tribal lands. The pipeline right-of-way lease expires in 2011, although Northern Border has an option to renew the pipeline right-of-way lease through 2061. In conjunction with obtaining a right-of-way across tribal lands located within the exterior boundaries of the Fort Peck Indian Reservation, Northern Border also obtained right-of-way across allotted lands located within the reservation boundaries. Most of the allotted lands are subject to a perpetual easement granted by the BIA for and on behalf of the individual Indian owners or obtained through condemnation. Several tracts are subject to a right-of-way grant that expires in 2015.

Insurance

The Partnership’s operations and activities are insured under TransCanada insurance programs, including property insurance, liability, automobile liability and workers compensation, in amounts which management believes are reasonable and appropriate.

Employees

The Partnership does not have any employees. In addition, none of our pipeline systems directly employ any of the persons responsible for managing or operating the pipeline systems or for providing them with services related to their day-to-day business affairs. Subsidiaries of TransCanada are the operators of all of our systems.

AVAILABLE INFORMATION

Our website is www.tcpipelineslp.com. We make available free of charge, on or through our website, our annual, quarterly and current reports, and any amendments to those reports, as soon as reasonably practicable after electronically filing or furnishing such reports with the SEC. Information contained on our web site is not part of this report.

Item 1A. Risk Factors

Cautionary Statement Regarding Forward-Looking Information

A number of statements made by TC PipeLines, LP in this Form 10-K filing are forward-looking and relate to, among other things, anticipated financial performance, business prospects, strategies, market forces and commitments. Much of this information appears in "Management's Discussion and Analysis of Financial Condition and Results of Operations" found herein. All forward-looking statements are based on the Partnership's current beliefs as well as assumptions made by and information currently available to the Partnership. These statements reflect the Partnership's current views with respect to future events. The Partnership assumes no obligation to update any such forward looking statements to reflect events or circumstances occurring after the date hereof. Words such as "anticipate," "believe," "estimate," "expect," "plan," "intend," "forecast," and similar expressions, identify forward-looking statements. By its nature, such forward-looking information is subject to various risks and uncertainties, including the risk factors discussed under Item 1A. "Risk Factors", which could cause TC PipeLines' actual results and experience to differ materially from the anticipated results or other expectations expressed in this

Form 10-K. Readers are cautioned not to place undue reliance on this forward-looking information, which is as of the date of this Form 10-K.

Each of the risks and uncertainties described below could lead to events or circumstances that may have a material adverse effect on our business, financial condition, results of operations and cash flows, including our ability to make distributions to our unitholders.

All of the information included in this report and any subsequent reports we may file with the SEC or make available to the public should be carefully considered and evaluated before investing in any securities issued by us.

The risks referred to herein refer to risks inherent in the Partnership and our pipeline systems.

RISKS INHERENT IN OUR BUSINESS

Cash distributions are dependent primarily on our cash flow, financial reserves and working capital borrowings.

Cash distributions are not dependent solely on our profitability, which is affected by non-cash items. Therefore, we may make cash distributions during periods when losses are reported and may not make cash distributions during periods when we report profits.

Factors that affect the actual amount of cash that we will have available for distribution to our unitholders include the following:

- the amount of cash set aside and the adjustment in reserves made by our general partner in its sole discretion;
- the level of capital expenditures made by our pipeline systems;
- the required principal and interest payments on our debt, retirement of debt and other liabilities including cost of acquisitions;
- the amount of cash distributed to us by the entities in which we own a non-controlling interest;
- our ability to borrow funds and access capital markets including the issuance of debt and equity securities; and
- restrictions on distributions contained in debt agreements.

We are dependent on our pipeline systems to generate sufficient cash to enable us to pay distributions.

The amount of cash we have quarterly to distribute to our common unitholders depends upon numerous factors, most of which are beyond our control and the control of our general partner, including:

- the rates charged and the volumes under contract for the transportation services of our pipeline systems;
- the quantities of natural gas available for transport and the demand for natural gas;
- legislative or regulatory action affecting demand for and supply of natural gas, and the rates our pipeline systems are allowed to charge in relation to their operating costs;
- the level of our pipeline systems' operating costs; and
- the creditworthiness of our pipeline systems' shippers.

If we do not identify opportunities for accretive growth through organic projects or acquisitions, or our pipeline systems do not successfully

complete expansion projects or make and integrate acquisitions that are accretive, our future growth may be limited.

A principal focus of our strategy is to continue to grow the cash distributions on our units by expanding our business. Our ability to grow depends on our ability to undertake acquisitions and organic growth projects, and the ability of our pipelines systems to complete expansion projects and make acquisitions that result in an increase in cash per unit generated from operations.

The long-term financial conditions of our pipeline systems are dependent on the continued availability of Western Canadian natural gas for import into the U.S. and the market demand for these volumes. Competition from pipelines that deliver natural gas from other supply sources to our pipeline systems' market areas could cause our pipeline systems to discount their rates or otherwise experience a reduction in their revenues.

The development of additional natural gas reserves requires significant capital expenditures by others for exploration and development drilling and the installation of production, gathering, storage, transportation and other facilities that permit natural gas to be produced and delivered to pipelines that interconnect with our pipeline systems. High exploration and production costs, low prices for natural gas, regulatory limitations such as royalty frameworks, or the lack of available capital for these projects could adversely affect the development of additional reserves in Western Canada and the production in the WCSB.

Volumes available for export out of the WCSB depend in part on the internal demand for Canadian natural gas which may increase as a result of increased demand for electricity generation and other industrial requirements, including the development of oil sands projects, which may require substantial amounts of natural gas. This higher internal demand may reduce the amount of gas available for import into the U.S. In the longer term, a portion of the Alberta hub gas supply may come from proposed gas pipelines from the North Slope of Alaska and the Mackenzie Delta of Canada and from the continued growth of coal bed methane projects. Cancellation or delays in the construction of such pipelines or such projects could adversely affect the volumes available for export in the long term.

If the availability of Alberta hub natural gas was to decline, existing shippers on our pipeline systems may be unlikely to extend their contracts and our pipeline systems may be unable to find replacement shippers for lost capacity. Furthermore, additional natural gas reserves may not be developed in commercial quantities and in sufficient amounts to fill the capacities of each of our pipeline systems.

In addition, existing customers may not extend their contracts if the cost of delivered natural gas from other producing regions into the markets served by our pipeline systems is lower than the cost of natural gas delivered by our pipeline systems. Our pipeline systems face increased competition from other pipelines that provide access for our shippers to capacity from the U.S. Rocky Mountain Region. The Rockies Express Pipeline owned by Rockies Express Pipeline LLC is being constructed in three phases and the planned terminus is in Clarington, Ohio. The first phase of The Rockies Express Pipeline is completed and currently delivering gas to interconnects in the Midwestern region. The Rockies Express Pipeline could result in significant downward pressure on natural gas prices in the Mid-continent Region, which could have an impact on Northern Border or Great Lakes.

An increase in competition in the key markets served by our pipeline systems could arise from new ventures or expanded operations from existing competitors. Our financial performance depends to a large extent on the capacity contracted on our pipeline systems. Decreases in the volumes transported by our pipeline systems, whether caused by supply or demand factors in the markets these pipeline systems serve, competition or otherwise, can directly and adversely affect our revenues and results of operations.

Our pipeline systems may not be able to maintain existing customers or acquire new customers when the current shipper contracts expire or customers may choose to recontract for shorter periods or at less than maximum rates.

The ability to extend and replace contracts on terms comparable to prior contracts or on any terms at all, could be adversely affected by factors, including:

- the supply of natural gas in Canada and the U.S.;
- competition from alternative sources of supply in the U.S.;
- competition from other pipelines, including their transportation rates or through their access to upstream supplies, as well as the proposed construction by other companies of additional pipeline capacity;
- the price of, and demand for, natural gas in markets served by our pipeline systems; and
- regulatory actions.

Ongoing changes in these factors and customers' ability to adjust to changing market conditions may cause Great Lakes and Northern Border to sell a significant portion of available capacity on a short-term basis. The weighted average life of Great Lakes' and Northern Border's contracts has generally declined over time. As of January 31,

2008, the weighted average remaining lives of Great Lakes' and Northern Border's contracts were 2.4 years and 1.3 years, respectively. Additionally, if the forward natural gas basis differentials do not support maximum rates, they may sell portions of their capacity at discounted rates. Any inability by Great Lakes and Northern Border to renew existing contracts at maximum rates or at all may have an adverse impact on their revenues and, as a result, cash distributions made to us.

If any significant shipper fails to perform its contractual obligations, our pipeline systems' respective cash flows and financial condition could be adversely impacted.

As of December 31, 2007, each of our pipeline systems has customers that account for more than ten per cent of their revenue. The loss of all or even a portion of the revenues associated with these customers, as a result of competition, creditworthiness or otherwise, could have a material adverse effect on the financial condition, results of operations and cash flows of our pipeline systems, unless they were able to contract for comparable volumes from other customers at favorable rates.

Sierra Pacific Power is Tuscarora's largest shipper, with firm contracts for approximately 69 per cent of its capacity. Sierra Pacific Resources and Sierra Pacific Power have non-investment grade credit ratings.

Our pipeline systems' transportation rates are subject to review and possible adjustment by federal regulators. If the FERC requires that our pipeline systems' tariff be changed, their respective cash flows may be adversely affected.

Under the Natural Gas Act (NGA), interstate transportation rates must be just and reasonable and not unduly discriminatory. Our pipeline systems are subject to extensive regulation by the FERC. The FERC's regulatory authority is not limited to but extends to matters including:

- transportation of natural gas;
- rates and charges;
- operating terms and conditions of service including creditworthiness requirements;
- types of services our pipeline systems may offer to their customers;
- construction of new facilities;
- extension or abandonment of service and facilities;
- accounts and records;
- depreciation and amortization policies;
- the acquisition and disposition of facilities;
- initiation and discontinuation of services; and
- standards of conduct business relations with certain affiliates.

Given the extent of regulation by the FERC and potential changes to regulations, we cannot predict:

- the likely federal regulations under which our pipeline systems will operate in the future;
- the effect that regulation will have on financial position, results of operations and cash flows of our pipeline systems and ourselves; or
- whether our cash flow will be adequate to make distributions to unitholders.

Great Lakes' last rate settlement expired on October 31, 2005 with no requirement to file a new rate proceeding or settlement. Northern Border and Tuscarora are currently operating under rate settlements which precludes a party to the rate settlements from bringing any rate actions prior to December 31, 2009 and May 31, 2010, respectively.

Action by the FERC on currently pending matters as well as matters arising in the future could adversely affect our pipeline systems' ability to establish or charge rates that would cover future increase in their costs, or even to continue to collect rates that cover current costs, including a reasonable return. We cannot assure unitholders that our pipeline systems will be able to recover all of their costs through existing or future rates.

Should our pipeline systems fail to comply with all applicable FERC administered statutes, rules, regulations and orders, our pipeline systems could be subject to substantial penalties and fines. Under the Energy Policy Act of 2005, the FERC has civil penalty authority under the NGA to impose penalties for current violations of up to $1 million per day for each violation.

Finally, we cannot give any assurance regarding the future regulations under which our pipeline systems will operate their natural gas transportation businesses, or the effect such regulations could ultimately have on our financial condition, results of operations and cash flows.

If our pipeline systems do not maintain their respective rate bases, the amount of revenue attributable to the return on the rate base they collect from their shippers will decrease over time.

Our pipeline systems are generally allowed to collect from their customers a return on their assets or "rate base" as reflected in their financial records as well as recover that rate base through depreciation. In the absence of additions to the rate base through capital expenditures, the amount they may collect from customers decreases as the rate base declines as a result of, among other things, depreciation and amortization.

Our pipeline systems' pipeline integrity programs may impose significant costs and liabilities.

The U.S. Department of Transportation rules require pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the rules refer to as "high consequence areas." The final rule resulted from the enactment of the Pipeline Safety Improvement Act of 2002. At this time, we cannot predict the total costs of compliance with this rule because those costs will depend on the extent of the pipeline testing and any subsequent repairs found to be necessary. Our pipeline systems completed the required 50 per cent inspection of their respective pipelines highest priority highest consequence segments of lines by the end of 2007. The remaining 50 per cent of each pipeline's highest priority highest consequence segments of pipeline is required to be inspected, and repaired if necessary, by 2012. After that point, the inspection is required to reoccur every seven years. Once 100 per cent of our pipeline systems have been inspected, we will have a better understanding of the total ongoing costs. Our pipeline systems will continue their pipeline integrity testing programs to assess and maintain the integrity of the pipelines. The results of this work could cause our pipeline systems to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of their pipelines.

Our pipeline systems' operations are regulated by federal, state and local agencies responsible for environmental protection and operational safety.

Risks of substantial costs and liabilities are inherent in pipeline operations and each of our pipeline systems may incur substantial costs and liabilities in the future as a result of stricter environmental and safety laws, regulations, and enforcement policies and claims for personal or property damages resulting from our pipeline systems' operations. Moreover, new, stricter environmental laws, regulations or enforcement policies could be implemented that significantly increase our pipeline systems' compliance costs or the cost of any remediation of environmental contamination that may become necessary, and these costs could be material. For instance, the U.S. Congress is actively considering federal legislation to reduce emissions of "greenhouse gases" (including carbon dioxide and methane). Several states of the U.S. have already taken legal measures to reduce emissions of greenhouse gases, and many other nations, not including the U.S., have also already agreed to regulate emissions of greenhouse gases. As a result of the regulation of greenhouse gases in the U.S., we may incur increased compliance costs to (i) operate and maintain our facilities; (ii) install new emission controls on our facilities; and (iii) administer and manage any greenhouse gas emissions reduction program that may be applicable to our operations. In addition, laws and regulations to reduce emissions of greenhouse gases could affect the consumption of natural gas and consequently, adversely affect the demand for our pipeline services and the rates we are able to collect for those services. If our pipeline systems are not able to recover these costs, cash distributions to unitholders could be adversely affected.

Our pipeline systems' indebtedness may limit their ability to borrow additional funds, make distributions to us or capitalize on business opportunities.

As of December 31, 2007, Great Lakes, Northern Border and Tuscarora had $440 million, $616 million and $66 million of debt outstanding, respectively. Their respective levels of debt could have important consequences to Great Lakes, Northern Border and Tuscarora, including the following:

- their ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or such financing may not be available on favorable terms;
- they will need a portion of their cash flow to make interest payments on the debt, reducing the funds that would otherwise be available for operations, future business opportunities and distributions to us, which will reduce our ability to make distributions to our unitholders;
- their debt level may make them more vulnerable to competitive pressures or a downturn in our business or the economy generally; and
- their debt level may limit their flexibility in responding to changing business and economic conditions.

Our pipeline systems' ability to service their debt will depend upon, among other things, future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, some of which are beyond their control.

In addition, under the terms of these financing arrangements, our pipeline systems are prohibited from making cash distributions during an event of default under their debt instruments. Under Great Lakes' debt instruments, Great Lakes has limitations on the level of indebtedness and has other restrictions, including a general prohibition against liens on pipeline facilities. Provisions in Northern Border's debt instruments limit its ability to incur indebtedness and engage in specific transactions. This could reduce its ability to capitalize on business opportunities that arise in the course of its business. Under Tuscarora's debt instruments, Tuscarora has granted a security interest in certain of its transportation contracts, which is available to noteholders upon an event of default. In addition, the Partnership's third party credit facility requires us to maintain certain financial ratios and contains restrictions on incurring additional debt and making distributions to partners.

We do not own a controlling interest in Great Lakes or Northern Border and we may be unable to cause certain actions to take place unless the other partner agrees. As a result, we will be unable to control the amount of cash we will receive from those operations and we could be required to contribute significant cash to fund our share of their operations. If we fail to make these contributions our ownership interest would be diluted.

The major policies of Great Lakes and Northern Border are established by each of their Management Committees.

Great Lakes' Management Committee consists of up to six members, three of whom are designated by us and three of whom are designated by TransCanada. Currently the committee consists of four appointed members, two of whom are designated by us and two of whom are designated by TransCanada. All decisions by the Management Committee require unanimous consent. An Executive Committee which consists of up to three members: one Partnership Committee Member, one TransCanada Committee Member and the Great Lakes' President, a non-voting member. Currently this committee consists of two appointed members: one Partnership Committee Member and one TransCanada Committee Member, who also serves as the Great Lakes president. The Executive Committee has all of the powers of the Management Committee in the management of Great Lakes' business. Because of these provisions, without the concurrence of TransCanada, we may be unable to cause Great Lakes to take or not to take certain actions, even though those actions may be in the best interest of us or Great Lakes.

Northern Border's Management Committee consists of four members, two of whom are designated by us and two of whom are designated by an affiliate of ONEOK. The Management Committee requires the affirmative vote of a majority of the partners' ownership interests to act on most activities. Certain activities require the unanimous consent of the committee, such as the filing of the application for regulatory authority to construct and operate new facilities and any changes to the cash distribution policy. Because of these provisions, without the concurrence of ONEOK, we may be unable to cause Northern Border to take or not to take certain actions, even though those actions may be in the best interest of us or Northern Border.

Great Lakes and Northern Border may require us to make additional capital contributions. Our funding of these capital contributions would reduce the amount of cash otherwise available for distribution to our unitholders. Additionally, in the event we elect not to, or are unable to, make a required capital contribution to Great Lakes or Northern Border, our ownership interest would be diluted.

Our pipeline systems' operations are subject to operational hazards and unforeseen interruptions, which could adversely affect their businesses and for which they may not be adequately insured.

Our pipeline systems' operations are subject to all of the risks and hazards typically associated with the operation of natural gas transportation pipeline systems. Operating risks include, but are not limited to, leaks, pipeline ruptures, the breakdown or failure of equipment or processes, and the performance of pipeline facilities below expected levels of capacity and efficiency. Other operational hazards and unforeseen interruptions include adverse weather conditions, accidents, the collision of equipment with our pipeline systems' pipeline facilities (which may occur if a third party were to perform excavation or construction work near these facilities), and catastrophic events such as explosions, fires, earthquakes, floods or other similar events beyond our pipeline systems' control. It is also possible that our pipeline systems' infrastructure facilities could be direct targets or indirect casualties of an act of terrorism. A casualty occurrence might result in injury or loss of life, extensive property damage or environmental damage. Liabilities incurred, and interruptions to the operation of our pipeline systems' facilities, for short or extended durations, caused by such an event, could reduce revenues generated by our pipeline systems and increase expenses, thereby impairing their ability to meet their obligations. Insurance proceeds may not be adequate to cover all liabilities or expenses incurred or revenues lost. Should one of our pipeline systems experience such an event, it may have an adverse impact on our results of operations and cash flow.

Our pipeline systems do not own all of the land on which their pipelines and facilities are located, which could disrupt their operations.

Our pipeline systems do not own all of the land on which their pipelines and facilities are located, and they are, therefore, subject to the risk of increased costs to maintain necessary land use. They obtain the rights to construct and operate certain of our pipelines and related facilities on land owned by third parties and governmental agencies for a specific period of time. Their loss of these rights, through their inability to renew right-of-way contracts or otherwise, or increased costs to renew such rights, could have a material adverse effect on their financial condition, results of operations and cash flows.

If we were to lose TransCanada's management expertise, we would not have sufficient stand-alone resources to operate.

TransCanada, through wholly-owned subsidiaries, is the operator of all our pipeline systems. We do not presently have sufficient stand-alone management resources to operate without services provided by TransCanada. Further, we would not be able to evaluate potential growth opportunities and successfully complete acquisitions without TransCanada's resources.

RISKS INHERENT IN AN INVESTMENT IN THE PARTNERSHIP

The Partnership's indebtedness may limit its ability to borrow additional funds, make distributions or capitalize on business opportunities.

As of December 31, 2007, the Partnership had $573 million of debt outstanding. This substantial level of debt could have important consequences to the Partnership including the following:

- our ability to obtain additional financing, if necessary, for working capital, acquisitions or other purposes may be impaired or such financing may not be available on favorable terms;
- we will need a portion of our cash flow to make interest payments on the debt, reducing the funds that would otherwise be available for operations, future business opportunities and distributions to our unitholders; and
- our debt level may limit our flexibility in responding to changing business and economic conditions.

Our ability to service our debt will depend upon, among other things, the future financial and operating performance of our pipeline systems, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, some of which are beyond our control.

In addition, our credit facilities contain restrictive covenants that may prevent us from engaging in certain transactions that we deem beneficial. These agreements require us to comply with various affirmative and negative covenants and maintaining certain financial ratios. There are restrictions and covenants with respect to:

- entering into mergers, consolidations and sales of assets;
- granting liens;
- material amendments to TC PipeLines' partnership agreement;
- incurring additional debt; and
- distributions to partners.

Any future debt may contain similar restrictions.

Increases in interest rates could materially adversely affect our business, results of operations, cash flows and financial condition.

As of December 31, 2007, TC PipeLines had approximately $507 million outstanding under the Senior Credit Facility, all of which was at variable interest rates. As a result, our results of operations, cash flows and financial condition could be materially adversely affected by significant increases in interest rates. From time to time, we may enter into interest rate swap arrangements, which decrease our exposure to variable interest rates. At December 31, 2007, approximately 80 per cent of the variable interest rate exposure related to the Partnership's $507 million of debt outstanding under the Senior Credit Facility was mitigated by fixed interest rate swap arrangements.

An increase in interest rates may also cause a corresponding decline in demand for equity investments, in general, and in particular for yield-based equity investments such as our common units. Any such reduction in demand for our common units resulting from other more attractive investment opportunities may cause the trading price of our common units to decline.

We do not have the same flexibility as other types of organizations to accumulate cash and equity to protect against illiquidity in the future.

Unlike a corporation, our partnership agreement requires us to make quarterly distributions to our unitholders of all available cash reduced by any amounts of reserves for commitments and contingencies, including capital and operating costs and debt service requirements. The value of our units and other limited partner interests may decrease in direct correlation with decreases in the amount we distribute per unit. Accordingly, if we experience a liquidity problem in the future, we may not be able to recapitalize by issuing more equity.

Unitholders have limited voting rights and do not control our general partner.

The general partner is our manager and operator. Unlike the holders of common stock in a corporation, holders of common units have only limited voting rights on matters affecting our business. Unitholders have no right to elect our general partner on an annual or other continuing basis. Our general partner may not be removed except by the vote of the holders of at least 66-$^{2}/_{3}$ per cent of the outstanding units and upon the election of a successor general partner by the vote of the holders of a majority of the outstanding common units. These required votes would include the votes of units owned by our general partner and its affiliates. The ownership of an aggregate of approximately 32 per cent of the outstanding units by our general partner and its affiliates has the practical effect of making removal of our general partner difficult.

In addition, the partnership agreement contains some provisions that may have the effect of discouraging a person or group from attempting to remove our general partner or otherwise change our management. If our general partner is removed as our general partner under circumstances where cause does not exist and units held by our general partner and its affiliates are not voted in favor of that removal:

- any existing arrearages in the payment of the minimum quarterly distributions on the common units will be extinguished; and
- our general partner will have the right to convert its general partner interests and its incentive distribution rights into common units or to receive cash in exchange for those interests.

These provisions may diminish the price at which the common units will trade under some circumstances.The partnership agreement also contains provisions limiting the ability of unitholders to call meetings of unitholders or to acquire information about our operations, as well as other provisions limiting the unitholders' ability to influence the manner or direction of management. Further, if any person or group other than our general partner or its affiliates or a direct transferee of our general partner or its affiliates acquires beneficial ownership of 20 per cent or more of any class of units then outstanding, that person or group will lose voting rights with respect to all of its units. As a result, unitholders will have limited influence on matters affecting our operations, and third parties may find it difficult to attempt to gain control of us, or influence our activities.

We may issue additional common units without unitholder approval, which would dilute existing unitholders' interest. In addition, issuance of additional common units may increase the risk that we will be unable to pay the full minimum quarterly distribution on all common units.

Our general partner can cause us to issue additional common units, without the approval of unitholders, in the following circumstances:

- under employee benefit plans, if any;
- upon conversion of the general partner interests and incentive distribution rights into common units as a result of the withdrawal of our general partner; or
- in connection with acquisitions or capital improvements that are accretive to our cash flow on a per unit basis.

In addition, we may issue an unlimited number of limited partner interests of any type without the approval of the unitholders. Based on the circumstances of each case, the issuance of additional common units or securities ranking senior to or on a parity with the common units may dilute the value of the interests of the then-existing holders of common units in the net assets of TC PipeLines and dilute the interests of unitholders in distributions by TC PipeLines. Our partnership agreement does not give the unitholders the right to approve the issuance by us of equity securities ranking junior to the common units at any time.

Any increase in the number of outstanding common units will increase the percentage of the aggregate minimum quarterly distribution payable to the common unitholders, which will in turn have the effect of increasing the risk that we will be unable to pay the minimum quarterly distribution in full on all the common units.

Unitholders may not have limited liability in some circumstances.

The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some states. If it were to be determined that:

- TC PipeLines had been conducting business in any state without compliance with the applicable limited partnership statute, or
- the right or the exercise of the right by the unitholders as a group to remove or replace our general partner, to approve some amendments to the partnership agreement or to take other action under the partnership agreement constituted participation in the “control” of TC PipeLines’ business,

then unitholders could be held liable in some circumstances for TC PipeLines’ obligations to the same extent as a general partner. In addition, under some circumstances a unitholder may be liable to TC PipeLines for the amount of a distribution for a period of three years from the date of the distribution.

Our general partner has a limited call right that may require unitholders to sell their common units at an undesirable time or price.

If our general partner and its affiliates, who currently own an aggregate of approximately 30.7 per cent of our common units, come to own 80 per cent or more of the common units, the general partner will have the right, which it may assign to any of its affiliates or us, to acquire all of the remaining common units held by unaffiliated persons at a price generally equal to the then current market price of the common units. As a consequence, unitholders may be required to sell their common units at a time when they may not desire to sell them or at a price that is less than the price they would desire to receive upon sale. Unitholders may also incur a tax liability upon a sale of their units.

Without the consent of each unitholder, Great Lakes, Northern Border or Tuscarora might be converted into a corporation, which would result in Great Lakes, Northern Border or Tuscarora, as the case may be, being subject to corporate income taxes.

If it becomes unlawful to conduct the business of Great Lakes, Northern Border or Tuscarora as a partnership and some other conditions are satisfied, the business and assets of Great Lakes, Northern Border or Tuscarora, as the case may be, will automatically be transferred to a corporation without the vote or consent of unitholders. Therefore, unitholders would not receive a proxy or consent solicitation statement in connection with that transaction. However, we believe that it is unlikely that circumstances requiring an automatic transfer will occur. A transfer to corporate form would result in Great Lakes, Northern Border or Tuscarora being subject to corporate income taxes and would likely be materially adverse to their, and therefore, our results of operations and financial condition.

TransCanada controls our general partner, which has sole responsibility for conducting our business and managing our operations. TC PipeLines GP, our general partner, and its affiliates have limited fiduciary responsibilities and may have conflicts of interest with respect to our partnership, and they may favor their own interests to the detriment of our unitholders.

The directors and officers of TC PipeLines GP and its affiliates have duties to manage TC PipeLines GP in a manner that is beneficial to its stockholders. At the same time, TC PipeLines GP has duties to manage our partnership in a manner that is beneficial to us. Therefore, TC PipeLines GP’s duties to us may conflict with the duties of its officers and directors to its stockholders. Such conflicts may include, among others, the following:

- decisions of TC PipeLines GP regarding the amount and timing of asset purchases and sales, cash expenditures, borrowings, issuances of additional common units and reserves in any quarter may affect the level of cash available to pay quarterly distributions to unitholders and TC PipeLines GP;
- under our partnership agreement, TC PipeLines GP determines which costs incurred by it and its affiliates are reimbursable by us;
- affiliates of TC PipeLines GP may compete with us in certain circumstances;
- TC PipeLines GP may limit our liability and reduce our fiduciary duties, while also restricting the remedies available to our unitholders for actions that might, without the limitations, constitute breaches of fiduciary duty. As a result of purchasing our units, unitholders are deemed to consent to some actions and conflicts of interest that might otherwise constitute a breach of fiduciary or other duties under applicable law;
- we do not have any employees and we rely solely on TC PipeLines GP and its affiliates to conduct our business, and
- TransCanada, through wholly-owned subsidiaries, is the operator of all of our pipeline systems. This operator role along with their ownership interest in Great Lakes may put TransCanada in a position to have to make decisions that may conflict as operator and/or owner of these systems.

Cost reimbursements due to our general partner may be substantial and could reduce our cash available for distribution.

Prior to making any distribution on the common units, we will reimburse our general partner and its affiliates, including officers and directors of the general partner, for all expenses incurred by our general partner and its affiliates on our behalf. During the year ended December 31, 2007, we paid fees and reimbursements to our general partner in the amount of $1.9 million. Our general partner in its sole discretion will determine the amount of these expenses. In addition, our general partner and its affiliates may provide us services for which we will be charged reasonable fees as determined by the general partner. The reimbursement of expenses and the payment of fees could adversely affect our ability to make distributions.

If we were found to be an "investment company" under the Investment Company Act of 1940, our contracts may be voidable and our offers of securities may be subject to rescission.

If we were deemed to be an unregistered "investment company" under the Investment Company Act, our contracts may be voidable and our offers of securities may be subject to rescission, and we may also be subject to other materially adverse consequences.

Our assets include a 46.45 per cent general partner interest in Great Lakes and a 50 per cent general partner interest in Northern Border. We could be deemed to be an "investment company" under the Investment Company Act if

these general partner interests constituted an "investment security", as defined in the Investment Company Act. If we were deemed to be an "investment company", then we would be required to be registered as an investment company under the Investment Company Act. In that case, there would be a substantial risk that we would be in violation of the Investment Company Act because of the practical inability to register under the Investment Company Act.

Tax Risks

The Internal Revenue Service ("IRS") could treat us as a corporation, which would substantially reduce the cash available for distribution to unitholders.

The anticipated after-tax benefit of an investment in us depends largely on our classification as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS on this or any other matter affecting us.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our income at the corporate tax rate, which is currently a maximum of 35 per cent. Distributions would generally be taxed again to unitholders as corporate distributions, and no income, gains, losses, deductions or credits would flow through to unitholders. Because a tax would be imposed upon us as an entity, the cash available for distribution to unitholders would be substantially reduced. Our treatment as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to unitholders and thus would likely result in a substantial reduction in the value of the common units.

Current law may change so as to cause us to be taxable as a corporation for federal income tax purposes or otherwise to be subject to entity level taxation. Our partnership agreement provides that, if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity level taxation for federal, state or local income tax purposes, then specified provisions of the partnership agreement relating to distributions will be subject to change. These changes would include a decrease in distributions to reflect the impact of that law on us.

If our pipeline systems were to become subject to a material amount of entity level taxation for state tax purposes, then our pipeline systems' operating cash flow and cash available for distribution to us and for other business needs would be reduced.

Our pipeline systems are partnerships or tax flow through entities, and as such they generally are not subject to income tax at the entity level. Several states are evaluating a variety of ways to subject partnerships to entity level taxation. One prevalent form of such taxation is a tax on gross receipts apportioned to a state. Imposition of such a tax on our pipeline systems by any state will reduce the cash available for distribution to us and for other business needs by our pipeline systems.

We have not requested an IRS ruling with respect to our tax treatment.

We have not requested a ruling from the IRS with respect to any matter affecting us. The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings in an effort to sustain some or all of our counsel's conclusions or the positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which the common units trade. In addition, the costs of any contest with the IRS will be borne directly or indirectly by some or all of the unitholders and the general partner.

Unitholders may be required to pay taxes on income from us even if they receive no cash distributions.

Unitholders may be required to pay federal income taxes and, in some cases, state and local income taxes on their allocable share of our income, whether or not they receive cash distributions from us. Unitholders may not receive cash distributions equal to their allocable share of our taxable income or even the tax liability that results from that income.

Tax gains or losess on the disposition of common units could be different than expected.

If unitholders sell their common units, they will recognize a gain or loss equal to the difference between the amount realized and their tax basis in those common units. Prior distributions in excess of the total net taxable income that unitholders were allocated for a common unit which decreased their tax basis in that common unit will, in effect, become taxable income if the common unit is sold at a price greater than their tax basis in that common unit, even if the price is less than the original cost. A substantial portion of the amount realized, whether or not representing a gain, may be ordinary income to unitholders. If the IRS successfully contests some conventions we use, unitholders could recognize more gain on the sale of common units than would be the case under those conventions without the benefit of decreased income in prior years.

Investors other than individuals who are U.S. residents may have adverse tax consequences from owning common units.

An investment in common units by tax-exempt entities, regulated investment companies and foreign persons raises issues unique to these persons. For example, virtually all of our income allocated to organizations exempt from federal income tax, including individual retirement accounts and other retirement plans, will be unrelated business taxable income and will be taxable to them. Net income derived from the ownership of certain publicly traded partnerships is treated as qualifying income to a regulated investment company. Distributions to foreign persons will be reduced by withholding taxes. Foreign persons will be required to file federal income tax returns and pay tax on their share of our taxable income.

We have registered as a "tax shelter." This may increase the risk of an IRS audit of TC PipeLines or a unitholder.

We have registered as a "tax shelter" with the Secretary of the Treasury. As a result, we may be audited by the IRS and tax adjustments could be made. Any unitholder owning less than a one per cent interest in us has a very limited right to participate in the income tax audit process. Further, any adjustments in our tax returns will lead to adjustments in unitholders' tax returns and may lead to audits of their tax returns and adjustments of items unrelated to us. Unitholders would bear the cost of any expenses incurred in connection with an examination of their personal tax return.

We treat a purchaser of common units as having the same tax benefits as the seller. A successful IRS challenge could adversely affect the value of the common units.

Because we cannot match transferors and transferees of common units, we have adopted depreciation and amortization conventions that do not conform to all aspects of specified Treasury regulations. A successful challenge to those conventions by the IRS could adversely affect the amount of tax benefits available to unitholders or could affect the timing of tax benefits or the amount of gain from the sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to unitholders' tax returns.

We have adopted certain valuation methodologies that may result in a shift of income, gain, loss and deduction between the general partner and the unitholders. The IRS may challenge this treatment, which could adversely affect the value of the common units.

For income tax purposes and pursuant to the Partnership Agreement, when we issue additional units or engage in certain other transactions, we determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our general partner. If our valuation methodology were not sustained upon an IRS challenge, there may be a shift of income, gain, loss and deduction between certain unitholders and the general partner, which may be unfavorable to such unitholders. Our valuation methodology is also used in certain computations and allocations relating to Section 743(b) adjustments and Section 751 deemed sale tax effects.

A successful IRS challenge to these methods, calculations or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from our

unitholders' sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

The sale or exchange of 50 per cent or more of the total interest in our capital and profits will result in the termination of our partnership for federal income tax purposes.

We will be considered to have terminated for federal income tax purposes if there is a sale or exchange of 50 per cent or more of the total interests in our capital and profits within a 12-month period. Our termination would, among other things, result in the closing of our taxable year for all unitholders and could result in a deferral of depreciation deductions allowable in computing our taxable income.

Unitholders will likely be subject to state and local taxes as a result of an investment in units.

In addition to federal income taxes, unitholders will likely be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property. Unitholders may be required to file state and local income tax returns and pay state and local income taxes in some or all of the jurisdictions in which we do business or own property and may be subject to penalties for failure to comply with those requirements. It is the unitholders' responsibility to file all required United States federal, state and local tax returns. Counsel has not rendered an opinion on the state or local tax consequences of an investment in us.

Item 1B. Unresolved Staff Comments

None.

Item 2 Properties

Excluding properties held directly by Tuscarora, TC PipeLines does not hold the right, title or interest in any properties.

Properties of Great Lakes Gas Transmission Limited Partnership, Northern Border Pipeline Company and Tuscarora Gas Transmission Company

See Item 1. "Business " for a description of our pipeline systems' properties, their utilization, and how each property is held.

Item 3. Legal Proceedings

Our pipeline systems are parties to various legal actions arising in the normal course of business. Management believes the disposition of all known outstanding legal actions will not have a material adverse impact on the Partnership's financial condition, results of operations or cash flows.

Item 4. Submission of Matters to a Vote of Security Holders

There were no matters submitted to a vote of security holders, through solicitation of proxies or otherwise, during the year ended December 31, 2007.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

The common units representing limited partner interests in the Partnership were issued pursuant to an initial public offering on May 28, 1999 and a private placement on February 22, 2007. The common units are quoted on the NASDAQ Global Select Market and trade under the symbol "TCLP."

On February 22, 2007, the Partnership completed a private placement of 17,356,086 common units at $34.57 per common unit for gross proceeds of $600.0 million. Net of issuing costs, the proceeds from the private placement were $594.4 million, which were used to fund a portion of the cash consideration for the Partnership's acquisition of a 46.45 per cent general partner interest in Great Lakes that closed concurrently with the private placement. TransCanada Northern purchased 8,678,045 of the 17,356,086 common units issued for gross proceeds of $300.0 million. In addition, TC PipeLines GP maintained its two per cent general partner interest in the Partnership by contributing $12.6 million to the Partnership in connection with the private placement.

The following table sets forth, for the periods indicated, the high and low sale prices per common unit, as reported by the NASDAQ Global Select Market, and the amount of cash distributions per common unit declared with respect to the corresponding periods. Cash distributions are paid within 45 days after the end of each quarter to unitholders of record as of the record date.

	Price Range		Cash Distributions Declared per Common Unit
	High	Low	
2007			
First Quarter	**$ 37.54**	**$ 35.29**	**$ 0.600**
Second Quarter	**$ 42.83**	**$ 36.34**	**$ 0.650**
Third Quarter	**$ 40.69**	**$ 32.98**	**$ 0.655**
Fourth Quarter	**$ 37.35**	**$ 35.50**	**$ 0.660**
2006			
First Quarter	$ 35.14	$ 32.60	$ 0.575
Second Quarter	$ 34.65	$ 31.54	$ 0.575
Third Quarter	$ 33.50	$ 30.41	$ 0.575
Fourth Quarter	$ 36.00	$ 30.00	$ 0.600

As of February 28, 2008, there were 96 registered holders of common units and approximately 13,800 beneficial owners of common units, including common units held in street name.

The Partnership currently has 34,856,086 common units outstanding, of which 24,142,935 are held by the public, 8,678,045 are held by TransCan Northern, and 2,035,106 are held by TC PipeLines GP. The common units represent an aggregate 98 per cent limited partner interest and the general partner interest represents an aggregate two per cent general partner interest in the Partnership.

The general partner receives two per cent of all cash distributions in regards to its general partner interest and is also entitled to incentive distributions as described below. The holders of common units (collectively referred to as unitholders) receive the remaining portion of the cash distribution. The Partnership's quarterly cash distributions to its unitholders comprise all of its Available Cash. Available Cash is defined in the partnership agreement and generally means, with respect to any quarter of the Partnership, all cash on hand at the end of a quarter less the amount of cash reserves that are necessary or appropriate, in the reasonable discretion of the general partner, to:

- provide for the proper conduct of the business of the Partnership (including reserves for future capital expenditures and for anticipated credit needs);
- comply with applicable laws or any Partnership debt instrument or agreement; or
- provide funds for cash distributions to unitholders and the general partner in respect of any one or more of the next four quarters.

The general partner receives incentive distributions if the amount distributed with respect to any quarter exceeds the minimum quarterly distribution of $0.45 per common unit. Under the incentive distribution provisions, the general partner receives 15 per cent of amounts distributed in excess of $0.45 per common unit, 25 per cent of amounts distributed in excess of $0.5275 per common unit, and 50 per cent of amounts distributed in excess of $0.69 per common unit, provided the balance has been first distributed to unitholders on a pro rata basis. The amounts that trigger incentive distributions at various levels are subject to adjustment in certain events, as described in the partnership agreement.

In 2007, the Partnership made cash distributions to unitholders and the general partner that amounted to $86.7 million compared to $43.5 million in 2006. These payments represented $0.60 per common unit for the quarter ended December 31, 2006, $0.65 per common unit for the quarter ended March 31, 2007, $0.655 for the quarter ended June 30, 2007 and $0.66 per common unit for the quarter ended September 30, 2007. On February 14, 2008, the Partnership paid a cash distribution of $25.6 million to unitholders and the general partner, representing a cash distribution of $0.665 per common unit for the quarter ended December 31, 2007. The distribution was allocated in the following manner: $23.2 million to the holders of common units as of the close of business on January 31, 2008 (including $1.4 million to the general partner as holder of 2,035,106 common units and $5.8 million to TransCan Northern as holder of 8,678,045 common units), $1.9 million to the general partner as holder of incentive distribution rights, and $0.5 million to the general partner in respect of its two per cent general partner interest.

Item 6. Selected Financial Data

The selected financial data should be read in conjunction with the financial statements, including the notes thereto, and Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations."

	Year Ended December 31				
(millions of dollars, except per unit amounts)	**2007(1)**	**2006(2)**	**2005**	**2004**	**2003**
Income Data					
Equity income from investment in Great Lakes	**49.0**	—	—	—	—
Equity income from investment in Northern Border	**61.2**	56.6	45.7	50.0	44.5
Equity income from investment in Tuscarora	—	5.9	7.5	7.5	5.3
Transmission revenues	**27.2**	0.9	—	—	—
Financial charges, net and other	**(33.8)**	(15.8)	(1.0)	(0.5)	(0.1)
Net income	**89.0**	44.7	50.2	55.1	48.0
Basic and diluted net income per unit	**$ 2.51**	$ 2.39	$ 2.70	$ 2.99	$ 2.63
Cash Flow Data					
Cash distribution paid per unit	**$ 2.565**	$ 2.325	$ 2.300	$ 2.275	$ 2.175
Balance Sheet Data (at December 31)					
Total assets	**1,492.6**	777.8	315.7	332.1	288.1
Long-term debt (including current maturities)	**573.4**	468.1	13.5	36.5	5.5
Partners' equity	**900.1**	303.9	301.6	294.9	282.0

(1) TC PipeLines acquired a 46.45 per cent interest in Great Lakes on February 22, 2007. The equity method is used to account for the Partnership's investment in Great Lakes.

(2) TC PipeLines accounted for its investment in Tuscarora using the equity method until December 19, 2006 and began consolidating Tuscarora's operations upon acquisition of the additional 49 per cent general partner interest.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discusses the results of operations and liquidity and capital resources of TC PipeLines, along with those of Great Lakes, Northern Border and Tuscarora (together "our pipeline systems") as a result of the Partnership's ownership interests.

The following discussions of the financial condition and results of operations of the Partnership and its pipeline systems should be read in conjunction with the financial statements and notes thereto of the Partnership, Great Lakes and Northern Border included elsewhere in this report. See Item 8. "Financial Statements and Supplementary Data". For more detailed information regarding the basis of presentation for the following financial information, see the notes to the financial statements of the Partnership, Great Lakes and Northern Border. All amounts are stated in U.S. dollars.

PARTNERSHIP OVERVIEW

TC PipeLines was formed in 1998 as a Delaware limited partnership. TC PipeLines was formed by TransCanada PipeLines Limited, a wholly-owned subsidiary of TransCanada Corporation (collectively referred to herein as TransCanada), to acquire, own and participate in the management of energy infrastructure assets in North America. Our strategic focus is on delivering stable, sustainable cash distributions to our unitholders and finding opportunities to increase cash distributions while maintaining a low risk profile.

TC PipeLines, LP and its subsidiaries are collectively referred to herein as "TC PipeLines" or "the Partnership." In this report, references to "we", "us" or "our" collectively refer to TC PipeLines or the Partnership. The general partner of the Partnership is TC PipeLines GP, Inc., a wholly-owned subsidiary of TransCanada.

We own a 46.45 per cent general partner interest in Great Lakes, which we acquired on February 22, 2007 from El Paso Corporation. The remaining 53.55 per cent general partner interest in Great Lakes is held by TransCanada.

We own a 50 per cent general partner interest in Northern Border, including a 20 per cent interest acquired on April 6, 2006. The remaining 50 per cent general partner interest in Northern Border is held by ONEOK Partners, a publicly traded limited partnership that is controlled by ONEOK, Inc.

We also own 100 per cent of Tuscarora. The Partnership acquired a 49 per cent interest from a wholly-owned subsidiary of TransCanada in September 2000. An additional 49 per cent was acquired from Tuscarora Gas Pipeline Co., a wholly-owned subsidiary of Sierra Pacific Resources, on December 19, 2006. On December 31, 2007, the Partnership acquired the remaining two per cent general partner interest in Tuscarora, with one per cent purchased from a wholly-owned subsidiary of TransCanada and the other one per cent purchased from Tuscarora Gas Pipeline Co.

The Partnership's general partner interests in Great Lakes, Northern Border and Tuscarora represent its only material assets at December 31, 2007. As a result, the Partnership is dependent upon Great Lakes, Northern Border and Tuscarora for all of its available cash.

Great Lakes Overview

Great Lakes is a Delaware limited partnership formed in 1990. Great Lakes' operating revenue is derived from transportation of natural gas. Great Lakes was originally constructed as an operational loop of the TransCanada Mainline Northern Ontario system. Great Lakes receives natural gas from TransCanada at the Canadian border near Emerson, Manitoba and extends across Minnesota, Northern Wisconsin and Michigan, and redelivers gas to TransCanada at the Canadian border at Sault Ste. Marie, Michigan and St. Clair, Michigan.

Northern Border Overview

Northern Border is a Texas general partnership formed in 1978. Northern Border's operating revenue is derived from transportation of natural gas. Northern Border transports natural gas from the Montana-Saskatchewan border near Port of Morgan, Montana to a terminus near North Hayden, Indiana. Additionally, Northern Border transports natural gas produced in the Williston Basin of Montana and North Dakota and the Powder River Basin of Wyoming and Montana and synthetic gas produced at the Dakota Gasification plant in North Dakota.

Tuscarora Overview

Tuscarora is a Nevada general partnership formed in 1993. Tuscarora's operating revenue is derived from transportation of natural gas. Tuscarora's U.S. interstate pipeline system originates at an interconnection point with existing facilities of Gas Transmission Northwest Corporation (GTN), a wholly-owned subsidiary of TransCanada, near Malin, Oregon and runs Southeast through Northeastern California and Northwestern Nevada. The Tuscarora pipeline system terminates near Wadsworth, Nevada. Along its route, deliveries are made in Oregon, Northern California and Northwestern Nevada. Deliveries are also made directly to the local gas distribution system of Sierra Pacific Power Company (Sierra Pacific Power), a subsidiary of Sierra Pacific Resources.

FACTORS THAT IMPACT OUR BUSINESS

Key factors that impact our business are the ability of Great Lakes and Northern Border to make distributions to us and of Tuscarora to generate positive operating cash flows and our ability to maintain a strong and balanced financial position. Partnership cash flows from our investments are necessary to generate sufficient cash to make distributions to our unitholders. A strong and balanced financial position will ensure that we are able to maintain a prudent level of available cash to make distributions to our unitholders.

FACTORS THAT IMPACT THE BUSINESS OF OUR PIPELINE SYSTEMS

Key factors that impact the business of our pipeline systems are the supply of and demand for natural gas in the markets in which our pipeline systems operate; the customers of our pipeline systems and the mix of services they require; competition; and government regulation of natural gas pipelines. These factors are discussed in more detail below.

Supply and Demand of Natural Gas

Our pipeline systems depend upon the continued availability of natural gas production and reserves in the regions we access, primarily the WCSB. Our pipeline systems provide their customers with natural gas transportation services to market demand areas. The amount of WCSB natural gas available for export is dependent upon natural gas production levels, demand for natural gas in Canada, and storage capacity for Canadian natural gas and demand for storage injection. Additional Canadian natural gas supply sources may be available in the future if new pipeline projects associated with the Mackenzie Delta in Northern Canada and the North Slope of Alaska are constructed.

Demand for natural gas transportation service on our pipeline systems is directly related to demand for natural gas in the markets served by these systems. Factors which may impact the overall demand for natural gas include weather conditions, economic conditions, government regulation, availability and price of alternative energy sources, fuel conservation measures, and technological advances in fuel economy and energy generation devices. Additionally, factors that may impact demand for transportation service on any one system include the ability and willingness of natural gas shippers to utilize one system over alternative pipelines, transportation rates, and the volume of natural gas delivered to markets from other supply sources and storage facilities.

Our pipeline systems depend upon the WCSB for the majority of the natural gas that they transport. There has been a decline in the flows out of WCSB over the last year. However, as discussed above, the impact of this decline on any given pipeline is dependent upon market conditions in the markets those pipelines serve. The decline in WCSB gas available for export did not negatively impact throughput on our pipeline systems in 2007. We cannot predict the impact of any export declines on 2008 throughput which will depend on WCSB natural gas available for export in the future and market conditions in the markets our pipeline systems serve.

The 2006-2007 winter was unusually warm in the markets served by Great Lakes. The low winter demand drove gas prices in the WCSB down and made it attractive to source gas in the supply area and move it to market instead of drawing storage gas. This increased utilization on the Great Lakes pipeline system. It also left Midwest storage levels at record highs, but in the post-Katrina environment when markets were disrupted by the hurricane, Great Lakes had sold its 2007 summer (and some winter 2006-2007) capacity on a firm basis so revenues were not adversely affected by lower than normal storage injection. Finally, with storage inventories at or near maximum, system demand was maintained late in the year by aggressively discounting to move available supply to markets.

Increased drilling and production activity in the Powder River Basin of Wyoming and Montana and the Williston Basin of Montana and North Dakota may present opportunities for Northern Border to pursue additional connections with this supply area. Future opportunities for potential additional supply include the construction of proposed coal gasificiation plants. A proposed coal gasification plant in North Dakota by Great Northern Power Development LP and Allied Syngas Corporation may also be a potential future supply source for Northern Border.

The GTN system is one of the U.S. transporters of Canadian natural gas from the WCSB, effectively the sole source of gas on Tuscarora. Tuscarora serves a number of markets along its route through Southern Oregon, Northern California and Northern Nevada. However, Tuscarora’s largest customers are in the Reno-Sparks area of Washoe County, Storey County and downstream of the Paiute system, where gas consumption related to industrial use, population growth and increased gas-fired power generation has grown significantly and is expected to continue.

Customers

Our pipeline systems transport natural gas for a variety of customers including other natural gas pipelines, natural gas distribution companies, electric generation companies, natural gas producers, and natural gas marketing and trading companies. Each type of customer has a different reason for using certain natural gas transportation services and routes. Natural gas distribution companies and electric generation companies typically require a secure and reliable supply of natural gas over a sustained period of time to meet the needs of their customers. These types of customers typically enter into long-term firm transportation contracts to ensure a ready supply of natural gas and sufficient transportation capacity over the life of their contracts. Natural gas producers typically enter into firm transportation contracts to ensure that they will have sufficient capacity to deliver their product to market centers. Natural gas marketing and trading companies typically use transportation services to capitalize on natural gas price volatility.

Competition

Our pipeline systems compete primarily with other interstate and intrastate pipelines in the transportation of natural gas. Additionally, supply competition from other natural gas sources can impact demand for transportation on our pipeline systems. Growth in supplies available from other natural gas producing regions can impact prices for natural gas delivered to some of the markets our pipeline systems serve relative to other market regions. An increase in the number of new pipeline projects in the U.S. has led to rising costs, both labor and materials, associated with new pipeline projects. These rising costs may impact our pipeline systems’ ability to pursue expansion projects.

Great Lakes competes directly with Northern Border, Alliance/Vector, Viking and the TransCanada Mainline. In addition, supply competition from other natural gas sources can impact demand for transportation on Great Lakes. Great Lakes anticipates that further growth in supplies from the Rocky Mountain region will create additional supply in the markets Great Lakes serves. Anticipated additional supplies from the Eastern segment of the Rockies Express Pipeline, discussed below, may provide opportunities for Great Lakes to market its Eastern zone capacity for storage injection and withdrawal, which has historically gone underutilized.

Northern Border serves natural gas markets in the Midwestern U.S. through major interconnects with other interstate natural gas pipelines. Northern Border also delivers natural gas directly to LDCs in Iowa, Illinois and Indiana. Two of Northern Border’s major interconnections are with

Northern Natural Gas at Ventura, Iowa and Natural Gas Pipeline at Harper, Iowa. Northern Border provides its customers with access to the Chicago market area, which is the third largest market area hub in North America. Supply competition from other natural gas sources in these markets can adversely impact demand for transportation on Northern Border's system. Northern Border has seen

growth in supplies from the Rocky Mountain region creating additional supply in the markets Northern Border serves, including Ventura, Harper and Chicago. Additional supply competition deliveries from other supply sources may impact Northern Border's ability to contract available capacity at Ventura and Harper beginning in April 2008 when approximately 37 per cent of its design capacity becomes uncontracted. Additional supply in the Chicago market may impact Northern Border's ability to contract available capacity in 2009 as long-term transportation contracts expire.

The Western segment of the Rockies Express Pipeline is increasing supply competition in Midwestern markets and could cause Northern Border to discount their rates or otherwise experience a reduction in their revenues. The Eastern segment of the Rockies Express Pipeline, from Missouri to Ohio, is expected to be placed in service by June 2009 (pending regulatory approvals), and is anticipated to transport natural gas further east, potentially mitigating excess supply in Northern Border's market region.

There are several other pipeline projects that have been announced, mostly moving gas from the U.S. Rocky Mountain Region to various regions of the U.S. Should any of these projects be built, they will have an impact on the U.S. natural gas markets, including the markets served by Northern Border and Great Lakes.

Tuscarora maintains a very strong competitive position relative to other sources of gas in the markets it serves. Tuscarora is one of only two pipelines that serves the Northern Nevada market, the other being Paiute Pipeline. Tuscarora can economically expand to meet the future gas transportation needs of the region by adding additional compression, which offers the greatest volume and pressure flexibility. Tuscarora also has access to supply regions as its upstream pipelines have excess capacity.

Government Regulation

Natural gas transportation is regulated by the FERC and other federal and state regulatory agencies, including the Department of Transportation. FERC regulatory policies govern the rates that pipelines are permitted to charge customers for interstate transportation of natural gas. The operation and maintenance of our pipeline systems are also impacted by the federal and state regulatory agencies.

The FERC-approved rate designs used by our pipeline systems are based upon firm service and interruptible services. Customers with firm service transportation agreements pay a fee known as a reservation charge to reserve pipeline capacity, regardless of use, for the term of their contracts. Firm service transportation customers may also pay a variable fee that is based on the distance and volume of natural gas they transport. Customers with interruptible service transportation agreements may utilize available capacity on a pipeline system after firm service transportation requests are satisfied. Interruptible service customers are assessed a variable fee based on distance and the volume of natural gas they transport. The majority of our pipeline systems' revenue is generated by firm service transportation agreements.

HOW WE EVALUATE OUR OPERATIONS

We evaluate our business primarily on the basis of the underlying operating results for each of our pipeline systems, along with a measure of Partnership cash flows. Partnership cash flows, a non-generally accepted accounting principle (GAAP) financial measure, is the sum of cash distributions received from Northern Border and Great Lakes, and cash flows from Tuscarora's operating activities less Partnership costs.

RESULTS OF OPERATIONS OF TC PIPELINES, LP

The general partner interests in Great Lakes, Northern Border and Tuscarora were our only material sources of income in 2007; therefore, our results of operations were influenced by and reflect the same factors that influenced the financial results of Great Lakes, Northern Border and Tuscarora. See Item 1. "Business".

Critical Accounting Policies and Estimates

The preparation of financial statements in accordance with U.S. GAAP requires us to make estimates and assumptions, with respect to values or conditions which cannot be known with certainty, that affect the reported

amount of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements. Such estimates and assumptions also affect the reported amounts of revenue and expenses during the reporting period. Although we believe these estimates and assumptions are reasonable, actual results could differ from our estimates. The following summarizes the Partnership's and our pipeline systems' accounting policies and estimates, which should be read in conjunction with Note 2 of the Partnership's Financial Statements included elsewhere in this report.

We account for our investments in Great Lakes and Northern Border using the equity method of accounting. The equity method of accounting is appropriate where the investor does not control an investee, but rather is able to exercise significant influence over the operating and financial policies of an investee. We are able to exercise significant influence over our investments in Great Lakes and Northern Border because of our ownership interests and our representation on the Great Lakes and Northern Border management committees.

We used the equity method to account for our investment in Tuscarora until December 19, 2006. On this date, we acquired an additional 49 per cent general partner interest in Tuscarora and, as a result of acquiring a controlling interest in Tuscarora, began to consolidate its operations. The consolidation method of accounting is appropriate where the investor controls the investee.

Regulatory Assets

Our pipeline systems' accounting policies conform to Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation*. Our pipeline systems consider several factors to evaluate their continued application of the provisions of SFAS No. 71 such as potential deregulation of their pipelines; anticipated changes from cost-based ratemaking to another form of regulation; increasing competition that limits their ability to recover costs; and regulatory actions that limit rate relief to a level insufficient to recover costs.

Certain assets that result from the ratemaking process are reflected on Northern Border's balance sheet as regulatory assets. If Northern Border determines future recovery of these assets is no longer probable as a result of discontinuing application of SFAS No. 71 or other regulatory actions, Northern Border would be required to write off the regulatory assets at that time. As of December 31, 2007, Northern Border reflected regulatory assets of $20.6 million on its balance sheet. These assets are being amortized as directed by the FERC in Northern Border's previous regulatory proceedings over varying time periods up to 43 years.

As at December 31, 2007, Great Lakes and Tuscarora did not have any regulatory assets or liabilities recorded on their respective balance sheets.

Contingencies

Our pipeline systems' accounting for contingencies covers a variety of business activities, including contingencies for legal and environmental liabilities. Our pipeline systems accrue for these contingencies when their assessments indicate that it is probable that a liability has been incurred or an asset will not be recovered and an amount can be reasonably estimated in accordance with SFAS No. 5, "Accounting for Contingencies." Our pipeline systems base their estimates on currently available facts and their estimates of the ultimate outcome or resolution. Actual results may differ from our pipeline systems' estimates resulting in an impact, positive or negative, on earnings.

Impairment of Long-Lived Assets and Goodwill

We assess our long-lived assets for impairment based on SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*. A long-lived asset is tested for impairment whenever events or changes in circumstances indicate that its carrying amount may exceed its fair value. Fair values are based on the sum of the undiscounted future cash flows expected to result from the use and eventual disposition of the assets.

We assess our goodwill for impairment at least annually, based on SFAS No. 142, *Goodwill and Other Intangible Assets.* An initial assessment is made by comparing the fair value of the operations with goodwill, as determined in accordance with SFAS No. 142, to the book value of each reporting unit. If the fair value is less than the book value, an impairment is indicated, and we must perform a second test to measure the amount of the impairment. In the second test, we calculate the implied fair value of the goodwill by deducting the fair value of all tangible and intangible net assets of the operations with goodwill from the fair value determined in step one of the assessment. If the carrying value of the goodwill exceeds this calculated implied fair value of the goodwill, we will record an impairment charge. At December 31, 2007, we had $81.7 million of goodwill recorded on our balance sheet related to the Tuscarora acquisitions.

Impact of New Accounting Standards

In 2006, the Financial Accounting Standards Board issued SFAS No. 157, *Fair Value Measurements,* and during 2007, issued SFAS No. 141(R), *Business Combinations - revised*, SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities – including an amendment of FASB Statement No. 115*, and SFAS No. 160, *Noncontrolling Interests in Consolidated financial Statements*.

SFAS No. 157 establishes a framework for measuring fair value and requires additional disclosures about fair value measurements. The effect of adopting SFAS No. 157 is not expected to be material to our results of operations or financial position.

SFAS No. 141(R) replaces SFAS No. 141, *Business Combinations*. SFAS No. 141 (R) retains the fundamental requirements of SFAS No. 141 that the acquisition method of accounting be used for all business combinations and for an acquirer to be identified for each business combination, with the objective of improving the relevance and comparability of the information that a reporting entity provides in its financial reports about a business combination and its effects. The requirements of this standard will not have a material impact on the results of the Partnership.

SFAS No. 159 permits entities to choose to measure selected financial assets and financial liabilities at fair value. The fair value option established by SFAS No. 159 permits all entities to choose to measure eligible items at fair value at specified election dates. The effect of adopting SFAS No. 159 is not expected to be material to our results of operations or financial position.

SFAS No. 160 clarifies the classification of noncontrolling interests in consolidated statements of financial position and the accounting for and reporting of transactions between the reporting entity and holders of such noncontrolling interests. The Partnership does not have noncontrolling interests and therefore, is not affected by the changes resulting from this standard.

In June 2007 the Emerging Issues Task Force of the FASB issued EITF 07-4, "Application of the Two-Class Method under FASB Statement No. 128, *Earnings per Share,* to Master Limited Partnerships". EITF 07-4 addresses how current period earnings of a Master Limited Partnership (MLP) should be allocated to the general partner, limited partners and when applicable, incentive distribution rights when applying the two-class method under Statement 128. A tentative conclusion was ratified by the FASB in December 2007. We are currently reviewing the applicability of EIFT 07-4 to our results of operations and financial position.

YEAR IN REVIEW

TC PipeLines

Acquisition of Interest in Great Lakes

On February 22, 2007, the Partnership acquired a 46.45 per cent general partner interest in Great Lakes from El Paso Corporation (El Paso). TransCanada, which previously held a 50 per cent interest in Great Lakes, acquired the other 3.55 per cent general partner interest simultaneously with the Partnership's acquisition of its interest. In connection with these transactions, a wholly-owned subsidiary of TransCanada became the operator of Great Lakes.

Equity Issuance

On February 22, 2007, the Partnership completed a private placement of 17,356,086 common units at $34.57 per common unit for gross proceeds of $600.0 million which closed concurrently with the Great Lakes acquisition. TransCan Northern purchased 8,678,045 of the 17,356,086 common units issued for gross proceeds of $300.0 million. In addition, TC PipeLines GP maintained its two per cent general partner interest in the Partnership by contributing $12.6 million to the Partnership in connection with the private placement.

Acquisition of Remaining Interest in Tuscarora

On December 31, 2007, TC PipeLines acquired the remaining two per cent general partner interest in Tuscarora, with one per cent purchased from a wholly-owned subsidiary of TransCanada and the other one per cent purchased from Tuscarora Gas Pipeline Co. TC PipeLines now owns 100 per cent of Tuscarora.

Great Lakes

Operating Revenues

For the period of March 1, 2007 to December 31, 2007, Great Lakes' average contracted capacity was 104 per cent. As of January 31, 2008, the weighted average remaining life of Great Lakes' contracts was 2.4 years.

Operating Data	**For the period February 23 to December 31, 2007**
MMcf delivered	**693,017**
MMcf/d average throughput	**2,221**

Regulatory Deferred Income Taxes

Income taxes are the responsibility of the partners and are not reflected in Great Lakes' financial statements prepared in accordance with GAAP. On the balance sheet prepared for regulatory accounting purposes, partners' capital is reduced by the amount equivalent to accumulated deferred income taxes.

The sale of El Paso's partnership interest, and a corresponding Internal Revenue Code Section 754 election, resulted in Great Lakes' pre-acquisition amounts equivalent to net deferred income tax liability balances being reduced by 46.45 per cent. In addition, Great Lakes' amounts equivalent to net deferred tax liabilities for pre-acquisition retirement plans were eliminated. Great Lakes' regulated partners' capital and amounts equivalent to net deferred tax liabilities were adjusted on February 22, 2007, by approximately $135 million as approved by the FERC.

Michigan Business Tax

In the third quarter of 2007, the state of Michigan enacted the Michigan Business Tax (MBT), which replaced the Michigan Single Business Tax (SBT), effective January 1, 2008. The MBT is an income tax levied at the partnership level. The MBT is expected to result in an annual income tax expense of approximately $4 to $5 million and to provide a property tax credit of approximately $1 million, for a net annual impact of $3 to $4 million to Great Lakes beginning in 2008. In September 2007, Great Lakes eliminated its deferred SBT amounts consistent with the elimination of the SBT tax. This resulted in an increase of $1.6 million to Great Lakes' net income.

Northern Border

Operating Revenues

Long-term rates were reduced and short-term seasonal rates were implemented effective January 1, 2007 as a result of Northern Border's rate case settlement, discussed later in this section. 2007 revenues were comparable to 2006 primarily due to the implementation of seasonal rates and a favorable contracting experience for 2007. Northern Border's average throughput and contracted capacity remained consistent from 2007 to 2006 as shown in the table below. The trend toward shorter term contracts and discounted transportation rates continued on Northern Border's system. The weighted average life of Northern Border's contracts declined from 1.8 years at December 31, 2006 to 1.3 years at January 31, 2008.

Operating Data	2007	2006
MMcf delivered	**799,637**	799,301
MMcf/d average throughput	**2,247**	2,246
Average contracted capacity	**97**%	97%

Settlement of Rate Case

The settlement of Northern Border's 2005 rate case was approved by the FERC in November 2006. The settlement established maximum long-term mileage-based rates and charges for transportation on Northern Border's system. Beginning January 1, 2007, overall rates were reduced, compared with rates prior to the filing, by approximately five per cent. For the full transportation route from Port of Morgan, Montana to the Chicago area, the previous charge of approximately $0.46 per Dth is now approximately $0.44 per Dth, which is comprised of a reservation rate, commodity rate and a compressor usage surcharge rate. The factors used in calculating depreciation expense for transmission plant were increased from 2.25 per cent to 2.40 per cent. The settlement also provided for seasonal rates for short-term transportation services. Seasonal maximum rates vary on a monthly basis from approximately $0.54 per Dth to approximately $0.29 per Dth for the full transportation route from Port of Morgan, Montana to the Chicago area.

Change in Operator

TransCanada Northern Border Inc. (TCNB), a wholly-owned subsidiary of TransCanada, became Northern Border's operator effective April 1, 2007 under a new operating agreement.

Tuscarora

Operating Revenues

Long-term rates were reduced effective June 1, 2006 as a result of Tuscarora's rate settlement, discussed later in this section. 2007 revenues were lower when compared to 2006 primarily due to the reduction of rates effective June 1, 2006. Tuscarora's average throughput and contracted capacity remained consistent from 2007 to 2006 as shown in the table below. The weighted average remaining life of Tuscarora's contracts declined from 11.4 years at December 31, 2006 to 10.4 years at December 31, 2007.

Operating Data	2007	2006
MMcf delivered	**28,257**	28,067
MMcf/d average throughput	**77**	77
Average contracted capacity	**96**%	96%

Cost and Revenue Study

On August 7, 2006, the FERC approved a settlement reached by Tuscarora, the PUCN and Sierra Pacific Power that resulted in a firm transportation rate of $0.40/decatherm per day (dth-day) effective June 1, 2006. This was a 17 per cent reduction to the previous rate of $0.4811/dth-day, or an approximate $5 million reduction in Tuscarora's annual revenues. In addition, the settlement resulted in a moratorium on all rate actions before the FERC by any party to the settlement for a period of 48 months to May 31, 2010, including rate actions related to expansion projects where Tuscarora proposes to price the expansion at the settlement rate.

2008 Expansion Project

Tuscarora filed an application with the FERC on November 20, 2006 for approval to construct the compressor station and related facilities (Tuscarora 2008 Expansion Project). This project is to transport a maximum of 39 MMcf/d to Sierra Pacific Power to supply its Tracy combined cycle power plant. The project is expected to cost approximately $20 million which will be recovered from rates charged to Sierra Pacific Power under the Transportation Service Agreement (TSA) signed with Sierra Pacific Power. The TSA is for a period of 22.5 years from the commencement date.

The FERC issued a Certificate of Public Convenience and Necessity for Tuscarora's 2008 Expansion Project on July 24, 2007 in response to Tuscarora's November 2006 application for approval to construct the compressor station and related facilities. The expansion is currently expected to go into service in March of 2008.

Net Income

To supplement our financial statements we have presented a comparison of the earnings contribution components from each of our investments. We have presented net income in this format in order to enhance investors' understanding of the way management analyzes the Partnership's financial performance. We believe this summary

provides a more meaningful comparison of the Partnership's net income to prior years, as we account for our partially owned pipeline systems using the equity method. The presentation of this additional information is not meant to be considered in isolation or as a substitute for results prepared in accordance with GAAP.

The shaded areas in the tables below disclose the results from Great Lakes, Northern Border and Tuscarora, representing 100 per cent of each entity's operations for the given period.

2007 (millions of dollars)	**Partnership**	**Tuscarora[(1)]**	**Corporate**	**Great Lakes[(2)] Feb 23 - Dec 31**	**Northern Border[(3)]**
Transmission revenues	**27.2**	27.2	—	236.2	309.4
Operating expenses	**(8.3)**	(4.9)	(3.4)	(53.7)	(83.5)
	18.9	22.3	(3.4)	182.5	225.9
Depreciation	**(6.3)**	(6.3)	—	(49.4)	(60.7)
Financial charges, net and other	**(33.8)**	(4.4)	(29.4)	(27.6)	(41.1)
				105.5	124.1
Equity income	**110.2**	—	—	49.0	61.2
Net income	**89.0**	11.6	(32.8)	49.0	61.2

(1) TC PipeLines owns a 100 per cent general partner interest in Tuscarora following the acqusition of an additional two per cent interest on December 31, 2007.

(2) TC PipeLines acquired a 46.45 per cent general partner interest in Great Lakes on February 22, 2007.

(3) TC PipeLines owns a 50 per cent general partner interest in Northern Border. Equity income from Northern Border includes amortization of a $10 million transaction fee paid to the operator of Northern Border at the time of the additional 20 per cent acquisition in April 2006.

2006 (millions of dollars)	**Partnership**	**Tuscarora[(4)] Dec 20 - Dec 31**	**Corporate**	**Tuscarora[(4)] Jan 1 - Dec 19**	**Northern Border[(5)]**
Transmission revenues	**0.9**	0.9	—	28.6	310.9
Operating expenses	**(2.7)**	(0.1)	(2.6)	(4.6)	(81.0)
	(1.8)	0.8	(2.6)	24.0	229.9
Depreciation	**(0.2)**	(0.2)	—	(6.0)	(58.7)
Financial charges, net and other	**(15.8)**	(0.2)	(15.6)	(5.1)	(41.3)
				12.9	129.9
Equity income	**62.5**	—	—	5.9	56.6
Net income	**44.7**	0.4	(18.2)	5.9	56.6

(4) With the acquisition of an additional 49 per cent general partner interest in Tuscarora on December 19, 2006, TC PipeLines changed its method of accounting for this investment from equity accounting to consolidation.

(5) Equity income from TC PipeLines' investment in Northern Border was based upon its 30 per cent ownership to April 5, 2006 and 50 per cent ownership following the acquisition of an additional 20 per cent general partner interest on April 6, 2006. Equity income from Northern Border includes amortization of a $10 million transaction fee paid to the operator of Northern Border at the time of the acquisition.

2005 (millions of dollars)	**Partnership**	**Corporate**	**Tuscarora[(6)]**	**Northern Border[(7)]**
Transmission revenues	—	—	32.3	321.7
Operating expenses	**(2.0)**	(2.0)	(4.4)	(70.8)
	(2.0)	(2.0)	27.9	250.9
Depreciation	—	—	(6.2)	(58.1)
Financial charges, net and other	**(1.0)**	(1.0)	(5.6)	(40.5)
			16.1	152.3

Equity income	**53.2**	—	7.5	45.7
Net income	**50.2**	(3.0)	7.5	45.7

(6) TC PipeLines owned a 49 per cent general partner interest in Tuscarora. Equity income from Tuscarora includes an acquisition allocation amortization related to the initial purchase of the Partnership's general partner interest in Tuscarora.

(7) TC PipeLines owned a 30 per cent general partner interest in Northern Border.

Year Ended December 31, 2007 Compared with the Year Ended December 31, 2006

Net income increased $44.3 million, or 99 per cent, to $89.0 million in 2007, compared to $44.7 million in 2006. This increase was due primarily to acquisition activities in 2007 and 2006. Equity income in 2007 included $49.0 million from our investment in Great Lakes, which we acquired on February 22, 2007. The Partnership's earnings increased $4.6 million in 2007 as a result of its ownership interest in Northern Border. Of this increase, $7.1 million is due to the additional 20 per cent general partner interest in Northern Border acquired on April 6, 2006, offset by a $2.5 million decrease due to a reduction in Northern Border's net income. The Partnership's earnings increased $5.1 million in 2007 as a result of its ownership interest in Tuscarora. Tuscarora contributed $11.4 million to the Partnership's earnings in 2007, including a $0.2 million non-controlling interest recorded by the Partnership. The Partnership's earnings increased by $6.0 million due to the additional 49 per cent general partner interest in Tuscarora acquired on December 19, 2006, offset by a $0.9 million decrease due to a reduction in Tuscarora's net income. The increase in the Partnership's earnings as a result of acquisitions is partially offset by a $13.8 million increase in the Partnership's financing costs.

Great Lakes' net income for the period from acquisition to December 31, 2007 was $105.5 million, in line with our expectations. The Partnership completed the acquisition of Great Lakes on February 22, 2007 and included 46.45 per cent of its earnings from this date. Great Lakes' revenues are primarily derived from its interstate natural gas transmission service. In 2007, approximately 91 per cent of Great Lakes' transportation revenues was derived from long-term firm service contracts.

Northern Border's net income decreased $5.8 million, or four per cent, to $124.1 million in 2007 compared to $129.9 million in 2006. Slight increases in depreciation and operating expenses, along with a small reduction in transmission revenues contributed to the decrease in net income. Depreciation expense increased by $2.0 million over the prior year primarily due to the change in depreciation rates effective January 1, 2007 as a result of the 2005 rate case settlement. Operating expenses increased $2.5 million over the prior year primarily due to a $2.3 million transition related charge in 2007 related to the reimbursement for shared equipment and furnishings acquired by ONEOK Partners and previously used to support Northern Border's operations. Increases in electric compression charges due to increased usage and electric rates were mostly offset by decreased taxes other than income. Excluding the positive impact of the higher ownership interest, the $5.8 million decrease in Northern Border's net income resulted in a $2.5 million decrease to the Partnership's net income.

Tuscarora's net income decreased $1.7 million, or 13 per cent, to $11.6 million in 2007. This decrease was mainly due to a full year impact of the settlement transportation rates that went into effect on June 1, 2006. The decrease in Tuscarora's net income contributed to a $0.9 million decrease to the Partnership's net income.

Year Ended December 31, 2006 Compared with the Year Ended December 31, 2005

Net income decreased $5.5 million, or 11 per cent, to $44.7 million in 2006, compared to $50.2 million in 2005. Net income of Northern Border and Tuscarora decreased in 2006 when compared to 2005 which contributed to an $8.1 million decrease in Partnership's earnings; however, this decrease was partially offset by an increased earnings contribution resulting from the 2006 acquisitions net of financing charges. The Partnership's earnings increased $17.6 million and $0.2 million in 2006 due to the acquisition of the additional 20 per cent interest in Northern Border and the additional 49 per cent general interest in Tuscarora, respectively. An increased outstanding debt balance resulted in increased financial charges of $14.8 million that partially offset the increases in earnings as a result of acquisitions.

Northern Border's net income decreased $22.4 million to $129.9 million in 2006, compared to $152.3 million in 2005. A one-time revenue amount related to the sale of the bankruptcy claims held against Enron by Northern Border in 2005 contributed $9.4 million to Northern Border's 2005 revenues. Decreased firm demand revenue and commodity charges were partially offset by additional revenue from transportation contracts related to the Chicago III Expansion Project. Increased operating expenses due to increased general and administrative expenses and electric compression charges associated with the Chicago III Expansion Project contributed $10.2 million to the decrease in net income at Northern Border. The $22.4 million decrease in Northern Border's net income contributed to a $6.7 million decrease to the Partnership's net income.

Tuscarora's net income decreased $2.8 million to $13.3 million in 2006, compared to $16.1 million in 2005, primarily due to lower net revenues resulting from settlement transportation rates that went into effect on June 1, 2006. The decrease in Tuscarora's net income contributed to a $1.4 million decrease to the Partnership's net income.

Partnership Cash Flows

To supplement our financial statements, we disclose "Partnership cash flows". We have presented this additional information to enhance investors' understanding of the way that management analyzes the Partnership's financial performance. We believe this summary provides a more meaningful comparison of the Partnership's financial performance to prior years, as Partnership cash flows fund the cash distributions that the Partnership pays to its unitholders. The presentation of this additional information is not meant to be considered in isolation or as a substitute for results prepared in accordance with GAAP.

(millions of dollars except per common unit amounts)	2007	2006	2005
Total cash distributions received[(a)]	**147.6**	88.1	69.2
Cash flows from Tuscarora's operating activities[(b)]	**19.9**	—	—
Partnership costs[(c)]	**(32.8)**	(18.2)	(3.0)
Partnership cash flows[(c)]	**134.7**	69.9	66.2
Partnership cash flows per common unit	**$ 4.17**	$ 3.99	$ 3.78
Cash distributions paid	**86.7**	43.5	43.0
Cash distributions paid per common unit	**$ 2.565**	$ 2.325	$ 2.300

[(a)] Reconciliation of non-GAAP financial measure: Total cash distributions received is a non-GAAP financial measure which is the sum of equity income from investment in Great Lakes, return of capital from Great Lakes, equity income from investment in Northern Border, return of capital from Northern Border and up until December 19, 2006, equity income from investment in Tuscarora and return of capital from Tuscarora. It is provided as a supplement to results reported in accordance with GAAP. Management believes that this is a meaningful measure to assist investors in evaluating the levels of cash distributions from the Partnership's investments. Below is a reconciliation of total cash distributions received to GAAP financial measures:

(millions of dollars)	2007	2006	2005
Equity income from investment in Great Lakes	**49.0**	—	—
Return of capital from Great Lakes	**12.3**	—	—
Cash distributions from Great Lakes	**61.3**	—	—
Equity income from investment in Northern Border	**61.2**	56.6	45.7
Return of capital from Northern Border	**25.1**	23.8	15.2
Cash distributions from Northern Border	**86.3**	80.4	60.9
Equity income from investment in Tuscarora	**—**	5.9	7.5
Return of capital from Tuscarora	—	1.8	0.8
Cash distributions from Tuscarora	—	7.7	8.3
Total cash distributions received	**147.6**	88.1	69.2

[(b)] Refer to Note 5 of the Partnership's financial statements for cash flows from Tuscarora's operating activities for the year ended December 31, 2007. TC PipeLines accounted for its investment in Tuscarora using the equity method until December 19, 2006 and began consolidating Tuscarora's operations upon acquisition of an additional 49 per cent general partner interest. Cash flows from Tuscarora's operating activities for 2006 have not been included in the above analysis as the Partnership effectively accounted for Tuscarora on a consolidated basis for only the last 11 days of the year.

[(c)] Reconciliation of non-GAAP financial measure: Partnership cash flows is a non-GAAP financial measure which is the sum of cash distributions received and cash flows from Tuscarora's operating activities less Partnership costs. We exclude Tuscarora's costs from the Partnership costs so that investors may evaluate our costs independent of costs directly attributable to our investments. Management believes that this is a useful measure to assist investors in evaluating the Partnership's cash flow from its operating activities. A reconciliation of Partnership costs is summarized below:

(millions of dollars)	2007	2006	2005
Operating expenses	**8.3**	2.7	2.0
Financial charges, net and other	**33.8**	15.8	1.0
Less:			
Operating expenses and financial charges from Tuscarora	**(9.3)**	(0.3)	—
Partnership costs	**32.8**	18.2	3.0

Year Ended December 31, 2007 Compared with the Year Ended December 31, 2006

Partnership cash flows increased $64.8 million, or 93 per cent, to $134.7 million in 2007, compared to $69.9 million in 2006. This increase was primarily a result of cash flows received from acquisitions made in 2007 and 2006. Partnership cash flows in 2007 included cash distributions received of $61.3 million resulting from the acquisition of Great Lakes. Cash distributions received from Northern Border increased $5.9 million in 2007 compared to the prior year due primarily to the additional 20 per cent interest in Northern Border. The Partnership began consolidating Tuscarora's operations on December 19, 2006, when it acquired a controlling interest in Tuscarora. Cash flows from Tuscarora's operating activities in 2007 were $19.9 million, while the distributions received from Tuscarora in 2006 were $7.7 million. Partnership costs increased $14.6 million to $32.8 million, compared to $18.2 million in 2006 primarily due to increased financial charges related to higher outstanding debt balances.

Excluding the returns of capital from our investments, the Partnership used $758.8 million of cash flows for investing activities in 2007 compared to $407.6 million used in 2006. In 2007, the Partnership acquired a 46.45 per cent general partner interest in Great Lakes from El Paso Corporation for $733.4 million in cash. In 2006, the Partnership incurred costs of $308.0 million to acquire an additional 20 per cent interest in Northern Border and $97.2 million related to its acquisition of the additional 49 per cent interest in Tuscarora. The Partnership made equity contributions of $7.5 million to Northern Border in 2007, compared to $3.1 million made in 2006. Tuscarora made capital expenditures of $13.2 million in 2007, of which $12.2 million related to the compressor station expansion project in Likely, California.

The Partnership generated $625.6 million of net cash flows from financing activities in 2007 compared to $337.6 million in 2006. The acquisition of a 46.45 per cent general partner interest in Great Lakes was partially financed through a private placement of 17,356,086 common units at $34.57 per common unit for gross proceeds of $600.0 million. In addition, TC PipeLines GP maintained its two per cent general partner interest in the Partnership by contributing $12.6 million to the Partnership in connection with the private placement. The Partnership funded the balance of the total consideration with a draw on its senior credit facility, which was amended and restated in connection with this transaction. The Partnership incurred $1.2 million of costs associated with the amended senior credit facility. The Partnership incurred debt of $171.5 million in 2007, which included $126.0 million in connection with the Great Lakes acquisition. The Partnership repaid $66.2 million of the outstanding balance on its senior credit facility and senior notes throughout the year.

Distributions paid by the Partnership increased $43.2 million, or 99 per cent, to $86.7 million in 2007 compared to $43.5 million in 2006 due to the increased number of common units outstanding and increases in quarterly per common unit distribution amounts declared in each of the last three quarters of 2007. In 2007, the Partnership paid the $86.7 million in distributions in the following manner: $79.0 million to common unitholders (including $5.2 million to the general partner as holder of 2,035,106 common units and $17.1 million to a TransCan Northern as holder of 8,678,045 common units), $5.9 million to the general partner as holder of the incentive distribution rights, and $1.8 million to the general partner in respect of its two per cent general partner interest.

Year Ended December 31, 2006 Compared with the Year Ended December 31, 2005

Partnership cash flows increased $3.7 million, or 6 per cent, to $69.9 million in 2006, compared to $66.2 million in 2005. Cash distributions received from Northern Border increased $19.5 million in 2006 compared to 2005. The additional 20 per cent ownership interest in Northern Border resulted in an additional $26.7 million in distributions received partially offset by a $7.2 million reduction in distributions attributable to the Partnerships' original 30 per cent interest in Northern Border. The Partnership's cash flows were also impacted by an increase in Partnership financial charges of $14.6 million due to the higher outstanding debt balance. Distributions made by Northern Border were higher in 2005 mainly due to higher revenues and $9.4 million realized on the sale of its unsecured bankruptcy claims held against Enron.

Excluding the returns of capital from our investments, the Partnership used $407.6 million of cash flows for investing activities in 2006 compared to $0.3 million used in 2005. In 2006, the Partnership incurred costs of $308.0 million to acquire an additional 20 per cent interest in Northern Border, and in addition, made equity contributions of $3.1 million which were used by Northern Border to repay indebtedness. The Partnership made a $0.3 million contribution to Tuscarora in 2005 related to construction of the Barrick Lateral.

The Partnership generated $337.6 million of cash flows from financing activities in 2006 compared to $66.0 million in cash flows used for financing activities in 2005. The increase in financing was to support the acquisition activities in 2006. To finance the 2006 acquisitions, the Partnership borrowed a net $383.5 million from bridge, term and revolving credit facilities. Tuscarora repaid $2.4 million of the outstanding balance on its senior secured notes in December 2006.

Distributions paid increased $0.5 million to $43.5 million in 2006 compared to $43.0 million in 2005. The increase was due to an increase in the Partnership's quarterly cash distribution from $0.575 per common unit to $0.60 per common unit beginning in the fourth quarter of 2006.

LIQUIDITY AND CAPITAL RESOURCES OF TC PIPELINES, LP

Overview

Our principal sources of liquidity include distributions received from our investments in Great Lakes and Northern Border, operating cash flow from Tuscarora and our bank credit facility. The Partnership funds its operating expenses, debt service and cash distributions primarily with operating cash flow. Long-term capital needs may be met through the issuance of long-term debt and/or equity.

Summary of the Partnership's Contractual Obligations

The Partnership's contractual obligations as of December 31, 2007 included the following:

	Payments Due by Period				
(millions of dollars)	**Total**	**Less Than 1 Year**	**2-3 Years**	**4-5 Years**	**After 5 Years**
Senior Credit Facility due 2011	507.0	—	—	507.0	—
Series A Senior Notes due 2010	54.5	3.3	51.2	—	—

Series B Senior Notes due 2010	5.5	0.5	5.0		—
Series C Senior Notes due 2012	6.4	0.8	1.7	3.9	—
Interest payments on Senior Credit Facility [(a)]	102.5	25.1	50.6	26.8	—
Interest payments on Senior Notes	13.4	4.7	8.4	0.3	—
Operating leases	0.1	0.1	—	—	—
Capital commitments [(b)]	3.0	3.0	—	—	—
	692.4	37.5	116.9	538.0	—

[(a)] Interest payments on Senior Credit Facility include the hedging effect of the derivative financial instruments placed on $475 million of the outstanding debt.

[(b)] Capital commitments relate to the Likely Compressor Station construction.

The Partnership's Debt and Credit Facilities

On March 31, 2006, the Partnership entered into an unsecured credit agreement for a $310.0 million credit facility (Bridge Loan Credit Facility) with a banking syndicate. Borrowings under the Bridge Loan Credit Facility bore interest, at the option of the Partnership, at the LIBOR or the base rate plus an applicable margin. On April 5, 2006, the Partnership borrowed $307.0 million under the Bridge Loan Credit Facility to finance the acquisition of an additional 20 per cent general partner interest in Northern Border. The remaining $3.0 million commitment under the Bridge Loan Credit Facility was terminated. On December 12, 2006, the Bridge Loan Credit Facility was refinanced through a $297.0 million draw on a $410.0 million credit agreement (Senior Credit Facility) with a banking syndicate and the use of $10.0 million cash on hand. The interest rate on the Bridge Loan Credit Facility averaged 6.29 per cent for the year ended December 31, 2006.

On December 12, 2006, the Partnership entered into a credit agreement for the Senior Credit Facility. On December 19, 2006, TC PipeLines borrowed an additional $100.0 million under the Senior Credit Facility to finance the acquisition of an additional 49 per cent interest in Tuscarora.

On February 13, 2007, the Senior Credit Facility was amended and restated in connection with the Great Lakes acquisition. The amount available under the Senior Credit Facility increased from $410.0 million to $950.0 million, consisting of a $700.0 million senior term loan and a $250.0 million senior revolving credit facility, with $194.0 million of the senior term loan available being terminated upon closing of the Great Lakes acquisition. In accordance with the Senior Credit Facility agreement, once repaid, a senior term loan cannot be re-borrowed. On November 29, 2007, $18.0 million of the senior term loan was repaid, and hence terminated, leaving $488.0 million available and outstanding under the senior term loan. At December 31, 2007, $19.0 million is outstanding under the senior revolving credit facility, leaving $231.0 million available for future borrowings.

The Senior Credit Facility matures on December 12, 2011, subject to two one-year extensions at the option of the Partnership and with the approval of a majority of the lenders thereunder. Amounts borrowed may be repaid in part or in full prior to that time without penalty. Borrowings under the Senior Credit Facility will bear interest based, at the Partnership's election, on the LIBOR or the prime rate plus, in either case, an applicable margin. There was $507.0 million outstanding under the Senior Credit Facility at December 31, 2007 (2006 - $397.0 million). The

interest rate on the Senior Credit Facility averaged 6.01 per cent for the year ended December 31, 2007 (2006 – 6.16 per cent). After hedging activity, the interest rate incurred on the Senior Credit Facility averaged 5.75 per cent for the year ended December 31, 2007. Prior to hedging activities, the interest rate was 5.62 per cent at December 31, 2007 (2006 – 6.07 per cent).

The Senior Credit Facility requires the Partnership to maintain a leverage ratio (debt to adjusted cash flow) of not more than 4.75 to 1.00 at the end of any fiscal quarter. The permitted leverage ratio will increase to 5.50 to 1.00 for the first three fiscal reporting periods during any 12-month period immediately following the consummation of specified material acquisitions. At December 31, 2007, the Partnership was in compliance with all of its financial covenants.

In 1995, Tuscarora issued $91.7 million of 7.13 per cent senior secured notes, which mature on December 21, 2010 (Series A). In 2000, Tuscarora issued $8.0 million of 7.99 per cent senior secured notes, which mature on December 21, 2010 (Series B). In 2002, Tuscarora issued $10.0 million of 6.89 per cent senior secured notes, which mature on December 21, 2012 (Series C). Series C proceeds were used to finance the construction of Tuscarora's expansion facilities. The Series A, Series B and Series C notes (collectively, the Notes) have a final payment at maturity of $46.7 million, $4.1 million and $2.7 million, respectively. The Notes are secured by Tuscarora's transportation contracts, supporting agreements and substantially all of Tuscarora's property. The credit agreement for the Notes contains certain provisions that include, among other items, limitations on additional indebtedness and distributions to partners. On December 31, 2007, $54.5 million, $5.5 million and $6.4 million were outstanding on the Series A, Series B and Series C Senior Notes, respectively. On December 31, 2006, $57.9 million, $6.0 million and $7.2 million were outstanding on the Series A, Series B and Series C Senior Notes, respectively.

Interest Rate Swaps and Options

The Partnership uses derivatives to assist in managing its exposure to interest rate risk. At December 31, 2007, the fair value of the interest rate swaps and options accounted for as hedges was negative $9.8 million (2006 - positive $1.6 million). The fair value of interest rate swaps and options have been calculated using year-end market rates. The notional amount hedged was $475 million. $300.0 million of variable-rate debt is hedged by an interest rate swap during the period from March 12, 2007 through December 12, 2011, where the weighted average fixed interest rate paid is 4.89 per cent. $100.0 million of variable-rate debt is hedged by an interest rate option during the period from May 22, 2007 through May 22, 2009 to an interest rate range between a weighted average floor of 4.09 per cent and a cap of 5.35 per cent. $75.0 million of variable-rate debt is hedged by an interest rate swap during the period from February 29, 2008 through February 28, 2011, where the fixed interest rate paid will be 3.86 per cent. In addition to these fixed rates, the Partnership pays an applicable margin in accordance with the Senior Credit Facility agreement. The interest rate swaps and options are structured such that the cash flows match those of the Senior Credit Facility.

Capital Requirements

In 2007, the Partnership made an equity contribution of $7.5 million to Northern Border, representing the Partnership's 50 per cent share of a $15.0 million cash call issued by Northern Border, which fulfilled the previously approved 2007 equity cash calls. The proceeds were used by Northern Border to repay indebtedness. In 2006, the Partnership made an equity contribution of $3.1 million, representing the Partnership's then 30 per cent share of a $10.3 million cash call issued by Northern Border, where the proceeds were used to fund a portion of the Chicago III Expansion Project capital costs.

In 2007, Tuscarora incurred $13.2 million of capital expenditures, of which $12.2 million related to its compressor station expansion in Likely, California. These capital expenditures were funded with operating cash flows. In 2005, the Partnership made an equity contribution of $0.3 million to Tuscarora, representing the Partnership's then 49 per cent share of a $0.7 million cash call issued by Tuscarora. Those proceeds were used to fund the construction of the Barrick Lateral that went into service June 2005.

To the extent the Partnership has any additional capital requirements with respect to our pipeline systems or makes acquisitions in 2008, we expect to fund these requirements with operating cash flows, debt and/or equity.

Cash Distribution Policy of TC PipeLines

The Partnership makes distributions of Available Cash, as defined in the Partnership Agreement, in the following manner:

- First, 98 per cent to the common units, pro rata, and two per cent to the general partner, until there is distributed for each outstanding common unit an amount equal to the minimum quarterly distribution for that quarter; and
- Thereafter, in a manner whereby the general partner has rights (referred to as incentive distribution rights) to receive increasing percentages of excess quarterly cash distributions over specified cash distribution thresholds calculated in the following manner:
  - First, 85 per cent to all units, pro rata, and 15 per cent to the general partner, until each unitholder has received a total of $0.5275 for that quarter;
  - Second, 75 per cent to all units, pro rata, and 25 per cent to the general partner, until each unitholder has received a total of $0.6900 for that quarter; and
  - Third, 50 per cent to all units, pro rata, and 50 per cent to the general partner.

The distribution to the general partner described above, other than in its capacity as a holder of 2,035,106 common units that are in excess of its aggregate two per cent general partner interest, represent the incentive distribution rights.

2007 Fourth Quarter Cash Distribution

On January 17, 2008, the Board of Directors of the general partner declared the Partnership's 2007 fourth quarter cash distribution. The fourth quarter cash distribution which was paid on February 14, 2008 to unitholders of record as of January 31, 2008, totaled $25.6 million and was paid in the following manner: $23.2 million to common unitholders (including $1.4 million to the general partner as holder of 2,035,106 common units and $5.8 million to TransCan Northern as holder of 8,678,045 common units), $1.9 million to the general partner as holder of the incentive distribution rights, and $0.5 million to the general partner in respect of its two per cent general partner interest.

LIQUIDITY AND CAPITAL RESOURCES OF OUR PIPELINE SYSTEMS

Overview

Our pipeline systems' principal source of liquidity is cash generated from operating activities and bank credit facilities. Our pipeline systems fund their operating expenses, debt service and cash distributions to partners primarily with operating cash flow.

Capital expenditures are funded by a variety of sources, including cash generated from operating activities, borrowings under bank credit facilities, issuance of senior notes or equity contributions from our pipeline systems' partners. The ability of our pipeline systems to access capital markets for debt under reasonable terms depends on their financial condition, credit ratings and market conditions.

Our pipeline systems believe that their ability to obtain financing at reasonable rates and their history of consistent cash flow from operating activities provide a solid foundation to meet their future liquidity and capital resource requirements.

Summary of Great Lakes' Contractual Obligations

Great Lakes' contractual obligations related to debt as of December 31, 2007 included the following:

	Payments Due by Period				
(millions of dollars)	**Total**	**Less Than 1 Year**	**2-3 Years**	**4-5 Years**	**After 5 Years**
8.74% series Senior Notes due 2008 to 2011	40.0	10.0	20.0	10.0	—
9.09% series Senior Notes due 2012 to 2021	100.0	—	—	10.0	90.0
6.73% series Senior Notes due 2009 to 2018	90.0	—	18.0	18.0	54.0
6.95% series Senior Notes due 2019 to 2028	110.0	—	—	—	110.0
8.08% series Senior Notes due 2021 to 2030	100.0	—	—	—	100.0
Interest payments on debt	390.0	34.2	64.3	58.3	233.2
	830.0	44.2	102.3	96.3	587.2

Long-Term Financing

All of Great Lakes' outstanding debt securities are senior unsecured notes with similar terms except for interest rates, maturity dates and prepayment premiums.

Great Lakes is required to comply with certain financial, operational and legal covenants. Under the most restricted covenants in the Senior Note Agreements, approximately $237.0 million of Great Lakes' partners' capital was restricted as to distributions as of December 31, 2007. In addition, Great Lakes is required to maintain a minimum consolidated tangible net worth of $175 million. At December 31, 2007, Great Lakes was in compliance with all of its financial covenants.

The aggregate estimated fair value of long-term debt was $525 million for 2007. The aggregate annual required repayments of senior notes are $10 million in 2008 and $19 million for each year 2009 through 2012. In 2007, interest expense related to Great Lakes' senior notes was $35 million.

Summary of Northern Border's Contractual Obligations

Northern Border's contractual obligations related to debt, operating leases and other long-term obligations as of December 31, 2007, included the following:

	Payments Due by Period				
(millions of dollars)	**Total**	**Less Than 1 Year**	**2-3 Years**	**4-5 Years**	**After 5 Years**
7.75% senior notes due 2009	200.0	—	200.0	—	—
7.50% senior notes due 2021	250.0	—	—	—	250.0
$250 million credit agreement due 2012	166.0	—	—	166.0	—
Interest payments on debt	321.3	43.1	65.6	49.3	163.3
Operating leases	72.1	2.5	4.7	3.8	61.1
Other long-term obligations	3.1	0.8	1.5	0.8	—
	1,012.5	46.4	271.8	219.9	474.4

Operating Leases

Northern Border is required to make future minimum payments for office space and rights-of-way under non-cancelable operating leases.

Other

Northern Border is required to pay $3.6 million over a five year period under a transition services agreement between ONEOK Partners GP and TransCanada Northern Border, related to the reimbursement for shared assets acquired by ONEOK Partners. In 2007, a charge of $2.3 million was recorded in operations and maintenance expense and $1.3 million was recorded as plant, property and equipment.

Amended and Restated Credit Agreement

On April 27, 2007, Northern Border entered into a $250 million amended and restated revolving credit agreement (the "2007 Credit Agreement") with certain financial institutions. The 2007 Credit Agreement was used to refinance the outstanding indebtedness under Northern Border's $175 million revolving credit agreement dated as of May 16, 2005 and was used to repay all of the $150 million of its 6.25 per cent Senior Notes due May 1, 2007. The 2007 Credit Agreement can also be used to finance permitted acquisitions, pay related fees and expenses, issue letters of credit and provide for ongoing working capital needs and for other general business purposes, including capital expenditures.

Northern Border may, at its option, so long as no default or event of default has occurred and is continuing, elect to increase the capacity under its 2007 Credit Agreement by an aggregate amount not to exceed $100 million, provided that lenders are willing to commit additional amounts. At

Northern Border's option, the interest rate on the outstanding borrowings may be the lenders' base rate or the LIBOR plus a spread that is based on its long-term unsecured credit ratings. The 2007 Credit Agreement permits Northern Border to specify the portion of the borrowings to be covered by specific interest rate options and to specify the interest rate period. Northern Border is required to pay a facility fee of 0.05 per cent based on the principal amount of the commitment of $250 million. The term of the agreement is five years, with options for two one-year extensions.

Under the 2007 Credit Agreement, Northern Border is required to comply with certain financial, operational and legal covenants. Among other things, Northern Border is required to maintain a ratio of total debt to EBITDA (net income plus interest expense, income taxes, depreciation and amortization and all other non-cash charges) of no more than 4.75 to 1. Pursuant to the 2007 Credit Agreement, if one or more acquisitions are consummated in which the aggregate purchase price is $25 million or more, the allowable ratio of total debt to EBITDA is increased to 5.50 to 1 for the first three full calendar quarters following the acquisition. Upon any breach of these covenants, amounts outstanding under the 2007 Credit Agreement may become immediately due and payable. At December 31, 2007, Northern Border was in compliance with all of its financial covenants.

The fair value of Northern Border's variable rate debt was approximately the carrying value since the interest rates are periodically adjusted to reflect current market conditions. As of December 31, 2007, Northern Border's outstanding borrowings under its credit agreement were $166 million. The average interest rate on Northern Border's credit agreement at December 31, 2007 was 5.35 per cent.

Interest Rate Collar Agreement

In August 2007, Northern Border entered into a zero cost interest rate collar agreement (the "Collar Agreement") to limit the variability of the interest rate on $140 million of variable-rate borrowings during the period from October 30, 2007 through October 30, 2009 to a range between a floor of 4.35 per cent and a cap of 5.36 per cent. Northern Border has designated the Collar Agreement as a cash flow hedge. At December 31, 2007, Northern Border's balance sheet reflected an unrealized loss of approximately $1.9 million with a corresponding decrease to accumulated other comprehensive income (loss) related to the changes in fair value of the Collar Agreement since inception. Since inception, Northern Border has not recognized any amounts in income due to ineffectiveness of the Collar Agreement.

Long-Term Financing - Debt Securities

Northern Border periodically issues long-term debt securities to meet its capital resource requirements. All of Northern Border's outstanding debt securities are senior unsecured notes with similar terms except for interest rates, maturity dates and prepayment premiums.

Northern Border's senior notes issuances of $200 million due in 2009 and $250 million due in 2021 are borrowed at fixed interest rates of 7.75 per cent and 7.50 per cent, respectively. Northern Border intends to maintain the current schedule of maturities, which will result in no gains or losses on their respective repayments. Northern Border intends to refinance the senior notes due in 2009 with a mix of long-term fixed rate debt and short-term variable rate debt. The indentures of the notes do not limit the amount of unsecured debt Northern Border may incur but do restrict secured indebtedness. In 2007, Northern Border repaid all of the $150 million of its 6.25 per cent senior notes due May 1, 2007 with borrowings under the 2007 Credit Agreement. At December 31, 2007, the aggregate fair value of the outstanding senior notes was approximately $493 million. In 2007, interest expense related to the senior notes was $37.4 million.

CASH FROM OUR PIPELINE SYSTEMS

Cash Distribution Policies of Great Lakes and Northern Border

Distributions to partners are made on a pro rata basis according to each general partner's ownership percentage, approximately one month following the end of a quarter. Great Lakes' and Northern Border's respective Management Committees determine the amount and timing of cash distributions, where the amount of such distributions is based on available cash flow as determined by a prescribed formula. Any changes to, or suspension of, Great Lakes' or Northern Border's cash distribution policy requires the unanimous approval of its respective Management Committee.

Northern Border's Management Committee changed its cash distribution policy effective in January 2004 to distribute 100 per cent of the distributable cash flow based on earnings before interest, taxes, depreciation and amortization less interest expense and maintenance capital expenditures. In 2006, upon the closing of the purchase and sale of the 20 per cent interest in Northern Border, the Northern Border Management Committee adopted certain changes to the Northern Border cash distribution policy related to financial ratio targets and equity contributions. The change defined minimum equity to total capitalization ratios to be used by the Northern Border Management Committee to establish the timing and amount of required equity contributions. In addition, any shortfall due to the inability to refinance maturing debt will be funded by equity contributions.

On February 1, 2008, a cash distribution of $46.3 million was declared and paid by Northern Border for the fourth quarter of 2007, of which TC PipeLines' 50 per cent share was $23.2 million. On February 1, 2008, a cash distribution of $25.0 million was declared and paid by Great Lakes for the fourth quarter of 2007, of which TC PipeLines' 46.45 per cent share was $11.6 million.

Investing Activities for our Pipeline Systems

Capital spending for maintenance of existing facilities and growth projects were as follows for each of our investments:

(millions of dollars)	2007	2006	2005

Great Lakes[a] :			
Maintenance	**16.7**		
Growth	**—**		
Great Lakes' capital spending	**16.7**		
Northern Border:			
Maintenance	**10.6**	10.4	18.3
Growth	**—**	10.5	10.3
Northern Border's capital spending	**10.6**	20.9	28.6
Tuscarora:			
Maintenance	**0.1**	0.3	0.2
Growth	**13.1**	1.3	0.7
Tuscarora's capital spending	**13.2**	1.6	0.9

[a] Great Lakes' capital spending information includes only capital expenditures from the date of acquisition.

Our pipeline systems fund their investing activities primarily with operating cash, issuances of new debt or additional borrowings under existing facilities, and equity contributions from general partners.

In 2008, Great Lakes expects to invest approximately $20.3 million for maintenance capital expenditures. No significant growth capital expenditures are planned for 2008.

Northern Border's maintenance capital expenditures decreased $7.9 million in 2006 compared with 2005 due to a decrease in expenditures related to compressor station overhauls. Growth capital expenditures in 2006 and 2005 were primarily related to spending for the Chicago III Expansion project. In 2008, Northern Border expects to spend approximately $30 million for capital expenditures of which $13 million relates to maintenance capital and $17 million relates to growth capital in regards to the Des Plaines project, subject to receipt of the required regulatory approvals. Northern Border intends to finance half of its growth capital expenditures with equity contributions from its general partners.

$12.2 million of Tuscarora's growth capital expenditures in 2007 relate to the compressor station expansion project in Likely, California. In 2008, Tuscarora expects to spend an additional $7.0 million to fund the completion of the compressor station expansion. Tuscarora expects to fund these capital expenditures with operating cash flow.

CONTINGENCIES

Legal

Various legal actions or governmental proceedings that have arisen in the ordinary course of business are pending. Our pipeline systems believe that the resolution of these issues will not have a material adverse impact on their results of operations or financial position.

Environmental

Our pipeline systems are not aware of any material contingent liabilities with respect to compliance with applicable environmental laws and regulations.

RELATED PARTY TRANSACTIONS

Great Lakes earns transportation revenues from TransCanada and its affiliates under fixed priced contracts with remaining terms ranging from one to ten years. Great Lakes earned $113.9 million of transportation revenues under these contracts for the period February 23, 2007 to December 31, 2007. This amount represents 48.2 per cent of total revenues earned by Great Lakes for the period February 23, 2007 to December 31, 2007. $52.9 million of transportation revenue is included in the Partnership's equity income from Great Lakes during the same period. Please read Item 1. "Business", Item 1A. "Risk Factors", and Item 13. "Certain Relationships and Related Transactions" for additional information regarding Great Lakes' transportation agreements with TransCanada and ANR.

OUTLOOK

Great Lakes

At January 31, 2008, the remaining weighted average contract life of Great Lakes' contracts was 2.4 years and substantially all of its design capacity was contracted on a firm basis for the first quarter of 2008. As of January 31, 2008, Great Lakes had approximately ten per cent of its design capacity uncontracted beginning in the second quarter of 2008. Dependent on competitive factors and prevailing market conditions, Great Lakes may discount transportation capacity as needed to optimize revenue.

Northern Border

At January 31, 2008, the weighted average contract life of Northern Border's contracts was 1.3 years and substantially all of its design capacity was contracted on a firm basis for the first quarter of 2008. As of January 31, 2008, Northern Border had approximately 890 MMcf/d or 37 per cent of its design capacity uncontracted beginning in the second quarter of 2008 and 48 per cent uncontracted by the end of 2008. Prevailing market conditions and increasing competitive factors in North America, including the Rockies Express Pipeline, could cause Northern Border to discount their rates or otherwise experience a reduction in their revenues. These factors will continue to impact Northern Border's ability to market this available capacity. Northern Border expects to continue to discount transportation capacity as needed to optimize revenue.

Tuscarora

At January 31, 2008, the weighted average remaining contract life of Tuscarora's contracts was 10.4 years. As of January 31, 2008, Tuscarora has approximately five MMcf/d or two per cent of its design capacity uncontracted beginning in the second quarter of 2008.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

OVERVIEW

Our exposure to market risk discussed below includes forward-looking statements and represents an estimate of possible changes in future earnings that would occur assuming hypothetical future movements in interest rates. Our views on market risk are not necessarily indicative of actual results that may occur and do not represent the maximum possible gains and losses that may occur, since actual gains and losses will differ from those estimated, based on actual fluctuations in interest rates and the timing of transactions.

TC PipeLines is exposed to market risk due to interest rate fluctuations. Market risk is the risk of loss arising from adverse changes in market rates. We utilize financial instruments to manage the risks of certain identifiable or anticipated transactions and achieve a more predictable cash flow. Our risk management function follows established policies and procedures to monitor interest rates to ensure our hedging activities mitigate market risks. We do not use financial instruments for trading purposes.

In accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* we record financial instruments on the balance sheet as assets and liabilities based on fair value. We estimate the fair value of financial instruments using available market information and appropriate valuation techniques. Changes in financial instruments' fair value are recognized in earnings unless the instrument qualifies as a hedge under SFAS No. 133 and meets specific hedge accounting criteria. Qualifying financial instruments' gains and losses may offset the hedged items' related results in earnings for a fair value hedge or be deferred in accumulated other comprehensive income for a cash flow hedge.

INTEREST RATE RISK

TC PipeLines' interest rate exposure results from its Senior Credit Facility, which is subject to variability in LIBOR interest rates. The Partnership regularly assesses the impact of interest rate fluctuations on future cash flows and evaluates hedging opportunities to mitigate its interest rate risk. The notional amount hedged at December 31, 2007 was $475.0 million. $300.0 million of variable-rate debt is hedged by an interest rate swap during the period from March 12, 2007 through December 12, 2011, where the weighted average fixed interest rate paid is 4.89 per cent. $100.0 million of variable-rate debt is hedged by an interest rate option during the period from May 22, 2007 through May 22, 2009 to an interest rate range between a weighted average floor of 4.09 per cent and a cap of 5.35 per cent. $75.0 million of variable-rate debt is hedged by an interest rate swap during the period from February 29, 2008 through February 28, 2011, where the fixed interest rate paid will be 3.86 per cent. The interest rate swaps and options are structured such that the cash flows match those of the Senior Credit Facility. The fair value of interest rate derivatives has been calculated using year-end market rates. At December 31, 2007, the fair value of the Partnership's interest rate swaps and options accounted for as hedges was negative $9.8 million.

At December 31, 2007, TC PipeLines had $507.0 million outstanding on its Senior Credit Facility. Utilizing the conditions of the interest rate swaps and options, if LIBOR interest rates hypothetically increased by one per cent compared to the rates in effect as of December 31, 2007, the Partnership's interest expense for the year ended December 31, 2007 would have increased by $1.4 million; and if LIBOR interest rates hypothetically decreased one per cent compared to the rates in effect as of December 31, 2007, the Partnership's interest expense for the year would have decreased by $2.0 million. These amounts have been determined by considering the impact of the hypothetical interest rates on variable rate borrowings outstanding as of December 31, 2007.

Northern Border utilizes both fixed-rate and variable-rate debt and is exposed to market risk due to the floating interest rates on its credit facility. Northern Border regularly assesses the impact of interest rate fluctuations on future cash flows and evaluates hedging opportunities to mitigate its interest rate risk. As of December 31, 2007, 73 per cent of Northern Border's outstanding debt was at fixed rates. In August 2007, Northern Border entered into a Collar Agreement to limit the variability of the interest rate on $140.0 million of variable-rate borrowings during the period from October 30, 2007 through October 30, 2009 to a range between a floor of 4.35 per cent and a cap of 5.36 per cent.

Utilizing the conditions of the Collar Agreement, if interest rates hypothetically increased one per cent compared with rates in effect as of December 31, 2007, Northern Border's annual interest expense would increase and its net income would decrease by approximately $0.8 million; and if interest rates hypothetically decreased one per cent compared with rates in effect as of December 31, 2007, Northern Border's annual interest expense would decrease and its net income would increase by approximately $1.1 million.

Great Lakes and Tuscarora utilize fixed-rate debt; therefore, they are not exposed to market risk due to floating interest rates.

OTHER RISKS

The Partnership is influenced by the same factors that influence our pipeline systems. None of our pipeline systems own any of the natural gas they transport; therefore, they do not assume any of the related natural gas commodity price risk.

The state of Minnesota currently requires Great Lakes to pay use tax on the value of the shipper provided compressor fuel burned in its Minnesota compressor engines. Great Lakes is subject to primarily commodity price volatility and some volume volatility in determining the amount of use tax owed. If natural gas prices changed by $1 per million British thermal units, Great Lakes' annual use tax expense would change by approximately $0.7 million.

The Partnership does not have any material foreign exchange risks.

Item 8. Financial Statements and Supplementary Data

The information required hereunder is included in this report as set forth in the "Index to Financial Statements" on page F-1.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

Based on their evaluation of the Partnership's disclosure controls and procedures as of the end of the year covered by this annual report, the principal executive officer and principal financial officer of the general partner of the Partnership have concluded that the Partnership's disclosure controls and procedures were effective in ensuring that the information required to be disclosed by the Partnership in the reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the

SEC's rules and forms and that information required to be disclosed by the Partnership in the reports that the Partnership files or submits under the Exchange Act is accumulated and communicated to the management of the general partner of the Partnership, including the principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control Over Financial Reporting

During the quarter ended December 31, 2007, there has been no change in the Partnership's internal control over financial reporting that has materially affected or is reasonably likely to materially affect our internal control over financial reporting.

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rule 13a-15(f) promulgated under the Securities Exchange Act of 1934. Internal control over financial reporting, no matter how well designed, has inherent limitations and can only provide reasonable assurance with respect to the preparation and fair presentation of published financial statements. Under the supervision and with the participation of our management, including our chief executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Based on our assessment according to the above criteria, management has concluded that our internal control over financial reporting was effective as of December 31, 2007 to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. generally accepted accounting principles. There were no material weaknesses.

Our independent registered public accounting firm, KPMG LLP, independently assessed the effectiveness of the Partnership's internal control over financial reporting. KPMG has issued an attestation report concurring with management's assessment, which is included on page F-3 of the financial statements included in this Form 10-K.

Item 9B. Other Information

None.

Part III

Item 10. Directors, Executive Officers and Corporate Governance

TC PipeLines is a limited partnership and as such has no officers, directors or employees. Set forth below is certain information concerning the directors and officers of the general partner who manage the operations of TC PipeLines. Each director holds office for a one-year term or until his or her successor is earlier appointed. All officers of the general partner serve at the discretion of the Board of Directors of the general partner which is a wholly-owned subsidiary of TransCanada.

Name	Age	Position with General Partner
Russell K. Girling	45	Chairman, Chief Executive Officer and Director
Mark A.P. Zimmerman	43	President
Jack F. Jenkins-Stark	57	Independent Director
David L. Marshall	68	Independent Director
Walentin (Val) Mirosh	62	Independent Director
Gregory A. Lohnes	51	Director
Kristine L. Delkus	50	Director
Steven D. Becker	57	Director
Terry C. Ofremchuk	57	Vice-President, Taxation
Sean M. Brett	42	Vice-President and Treasurer
Donald J. DeGrandis	59	Secretary
Amy W. Leong	40	Controller, Principal Financial Officer

Mr. Girling was appointed a director of the general partner in April 1999 and Chief Executive Officer of the general partner in June 2006. Mr. Girling's principal occupation is President, Pipelines Division of TransCanada, a position he has held since June 2006. From March 2003 to June 2006, he was Executive Vice-President, Corporate Development and Chief Financial Officer of TransCanada. Prior to March 2003, Mr. Girling was Executive Vice-President and Chief Financial Officer of TransCanada. Mr. Girling is also a director of Agrium Inc.

Mr. Zimmerman was appointed President of the general partner in January 2007. Mr. Zimmerman's principal occupation is Vice-President, Commercial Transactions of TransCanada, a position he has held since June 2006. From September 2003 to June 2006, he was Director, Project Finance for TransCanada, and prior to September 2003, he was Director, Corporate Evaluations and Planning for TransCanada.

Mr. Jenkins-Stark was appointed a director of the general partner in July 1999. Mr. Jenkins-Stark's principal occupation is Chief Financial Officer of BrightSource Energy Inc. (designs and builds large scale solar plants that deliver solar energy in the form of steam and/or electricity), a position he has held since April 2007. Mr. Jenkins-Stark was Chief Financial Officer of Silicon Valley Bancshares (offering financial products and services, including commercial, investment, merchant and private banking and private equity services) from April 2004 to April 2007. Prior to that he was Vice-President, Business Operations and Technology at Itron Inc. (a manufacturer of automated meter reading technology and a developer of energy management software), a position he held from January 2004 to March 2004. In March 2003, Mr. Jenkins-Stark was named a Managing Director at Itron Inc. following the purchase of Silicon Energy Corp. (internet-based energy and data management software) by Itron Inc. Prior to the acquisition, Mr. Jenkins-Stark was Chief Financial Officer of Silicon Energy.

Mr. Marshall was appointed a director of the general partner in July 1999. Mr. Marshall is a corporate director.

Mr. Mirosh was appointed a director of the general partner in September 2004. Mr. Mirosh's principal occupation is Vice-President of NOVA Chemicals Corporation and President of Olefins and Feedstocks, division of NOVA Chemicals Corporation (commodity chemical company), a position he has held since July 2003. Mr. Mirosh was Partner, MacLeod, Dixon (law firm) from January 2002 to July 2003. Mr. Mirosh is also a director of Taylor NGL Limited Partnership and Superior Plus Income Fund.

Mr. Lohnes was appointed a director of the general partner in January 2007. Mr. Lohnes' principal occupation is Executive Vice-President and Chief Financial Officer of TransCanada, a position he has held since June 2006. Prior to June 2006, he was President and Chief Executive Officer of Great Lakes Gas Transmission Company.

Ms. Delkus was appointed a director of the general partner in November 2003. Ms. Delkus' principal occupation is Deputy General Counsel, Pipelines and Regulatory Affairs of TransCanada, a position she has held since September 2006. From June 2006 to September 2006, she was Vice-President, Pipeline Law and Regulatory Affairs of TransCanada. From December 2005 to June 2006, she was Vice-President, Law, Gas Transmission of TransCanada. Prior to December 2005, she was Vice-President, Law, Power and Regulatory.

Mr. Becker was appointed a director of the general partner in January 2007 and appointed Vice-President, Business Development of the general partner in September 2003. Mr. Becker's principal occupation is Vice-President, Pipeline Development of TransCanada, a position he has held since June 2006. From April 2003 to June 2006, he was Vice-President, Gas Development of TransCanada. Prior to April 2003, Mr. Becker was Vice-President, Market Development and Vice-President, Gas Strategy of TransCanada.

Mr. Ofremchuk was appointed Vice-President, Taxation of the general partner in July 2007. Mr. Ofremchuk's principal occupation is Manager, Corporate Taxation of TransCanada.

Mr. Brett was appointed Vice-President and Treasurer of the general partner in January 2007. Mr. Brett's principal occupation is Assistant

Treasurer for TransCanada, a position he has held since January 2007. Prior to January 2007, he was Director, Capital Markets for TransCanada.

Mr. DeGrandis was appointed Secretary of the general partner in April 2005. Mr. DeGrandis' principal occupation is Corporate Secretary of TransCanada, a position he has held since June 2006. From June 2004 to June 2006, he was Associate General Counsel, Corporate, Corporate Secretarial of TransCanada. Prior to June 2004, Mr. DeGrandis was Director of Corporate Legal Services and Senior Legal Counsel of TransCanada.

Ms. Leong was appointed principal financial officer of the general partner in January 2007 and Controller of the general partner in September 2003. Ms. Leong's principal occupation is Director, Pipeline Accounting of TransCanada, a position she has held since January 2005. From April 2003 until January 2005, Ms. Leong was Manager, Gas Transmission Accounting of TransCanada. Prior to April 2003, Ms. Leong was Manager, Regulatory Accounting and Capital Accounting of TransCanada.

AUDIT COMMITTEE FINANCIAL EXPERT

The Board of Directors has determined that David Marshall and Jack Jenkins-Stark are "audit committee financial experts", are "independent" and are "financially sophisticated" as defined under applicable SEC and NASDAQ Stock Market Corporate Governance rules. The Board's affirmative determination for both David Marshall and Jack Jenkins-Stark was based on their respective education and extensive experience as chief financial officers for corporations that presented a breadth and level of complexity of accounting issues that are generally comparable to those of TC PipeLines.

IDENTIFICATION OF THE AUDIT COMMITTEE

The general partner of the Partnership has a separately designated audit committee consisting of three independent board members. The members of the committee are David Marshall, as Chair, Jack Jenkins-Stark and Walentin (Val) Mirosh. All members of the Audit Committee meet the criteria for independence as set forth under the rules of the SEC and those of the NASDAQ Stock Market. None of the Audit Committee members have participated in the preparation of the financial statements of the Partnership or any of its subsidiaries at any time during the past three years. In addition, all members of the audit committee are able to read and understand fundamental financial statements, including a company's balance sheet, income statement, and cash flow statement.

CODE OF ETHICS

TC PipeLines believes that director, management and employee honesty and integrity are important factors in ensuring good corporate governance. The employees of the general partner, as employees of TransCanada, are subject to TransCanada's code of business ethics. In addition, the general partner has adopted a code of business ethics for its Chief Executive Officer, President and Principal Financial Officer and one which applies to its independent directors, being the code of business ethics for directors. All codes are published on its website at www.tcpipelineslp.com. If any substantive amendments are made to the code for senior officers or if any waivers are granted, the amendment or waiver will be published on TC PipeLines' website or filed in a report on Form 8-K.

CORPORATE GOVERNANCE

The Audit Committee has adopted a charter which specifically provides that it is responsible for the appointment, compensation, retention and oversight of the work of the independent public accountants engaged in preparing or issuing TC PipeLines' audit report, that the committee has the authority to engage independent counsel and other advisors as it determines necessary to carry out its duties and for the committee to be responsible for establishing procedures for the receipt, retention and treatment of complaints regarding accounting, internal accounting controls or auditing matters, including procedures for the confidential, anonymous submission by employees of the general partner concerns regarding questionable accounting or auditing matters. The committee has adopted TransCanada's Ethics help line in fulfillment of its responsibility to establish a confidential and anonymous whistle blowing process. The toll free Ethics Help-Line number and the audit committee's charter are published on TC PipeLines' website at www.tcpipelineslp.com.

SECTION 16(a) BENEFICIAL OWNERSHIP REPORTING COMPLIANCE

Section 16(a) of the Exchange Act requires the Partnership's directors and executive officers, and persons who own more than ten per cent of the common units, to file initial reports of ownership and reports of changes in ownership (Forms 3, 4, and 5) of the common units with the SEC and the NASDAQ Global Market. Executive officers, directors and greater than ten per cent unitholders are required by SEC regulation to furnish the Partnership with copies of all such forms that they file.

Based solely upon a review of reports on Forms 3 and 4 and amendments thereto furnished to the Partnership during its most recent fiscal year and reports on Form 5 and amendments thereto furnished to the Partnership with respect to its most recent fiscal year, and written representations from officers and directors of the general partner that no Form 5 was required, the Partnership believes that all filing requirements applicable to its officers, directors and beneficial owners under Section 16(a) were complied with during the year ended December 31, 2007.

Item 11. Executive Compensation

COMPENSATION DISCUSSION AND ANALYSIS

We are a master limited partnership and we do not directly employ any of the individuals responsible for managing or operating our business nor do we have any directors. We are managed by the executive officers of our general partner who are also our executive officers. The executive officers of our general partner are compensated directly by TransCanada.

The compensation policies and philosophy of TransCanada govern the types and amount of compensation granted each of the named executive officers. Since these policies and philosophy are those of TransCanada, we refer you to a discussion of those items as set forth in the Executive Compensation section of the TransCanada "Management Proxy Circular" on the TransCanada website at www.transcanada.com. The TransCanada "Management Proxy Circular" is produced by TransCanada pursuant to Canadian securities regulations and is not incorporated into this document by reference or deemed furnished or filed by us under the Securities Exchange Act of 1934, as amended; rather the reference is to provide our investors with an understanding of the compensation policies and philosophy of the ultimate parent of our general partner.

The board of directors of our general partner does not have a separate compensation committee, nor does it make any determination with respect to the amount of compensation to be paid to our executive officers. The board of our general partner does have responsibility for evaluating and determining the reasonableness of the total amount we are charged for managerial, administrative and operational support provided by TransCanada, and its affiliates, including our general partner. The board specifically approves the allocation of the salary of the CEO to the Partnership on an annual basis. Please read Item 13. "Certain Relationships and Related Transactions" for more information regarding this arrangement.

In addition to base salary, we also reimburse our general partner for certain benefit and incentive compensation expenses related to the officers of our general partner and employees of an affiliate of our general partner who perform services on our behalf. The base salaries that are allocable to us vary for each officer or employee of an affiliate of our general partner performing services on our behalf and are based on the amount of time an employee devotes to matters related to our business as compared to the amount of time such employee devotes to matters related to the business of TransCanada and its other affiliates. We are allocated and reimburse the general partner for

each officer's salary expense. Other benefit and incentive compensation expenses related to our officers are reimbursed to the general partner based upon an agreed upon calculation.

The following table summarizes the salary allocated to and paid by us in 2006 and 2007 for our principal executive officer, president and principal financial officers. None of the other executive officers of our general partner allocated to us more than $100,000 related to their salary.

Summary Compensation Table

		Base Salary Allocated to the Partnership		
Name and Principal Position	**Year**	**Canadian Dollars**	**United States Dollar Equivalent (1)**	**Total (1)**
Russell K. Girling, Chief Executive Officer	2007	60,250	60,973	60,973
	2006	49,835	42,763	42,763
Mark A.P. Zimmerman, President	2007	102,500	103,729	103,729
Gregory A. Lohnes, Chief Financial Officer	2007	—	—	—
	2006	—	—	—
Amy W. Leong, Controller and Principal Financial Officer	2007	16,475	16,673	16,673
	2006	15,500	13,301	13,301

(1) The compensation of executive officers of the general partner is paid by TransCanada in Canadian dollars. The United States dollar equivalents have been calculated using the applicable December 31, 2007 and 2006 noon buying rates of 1.0120 and 0.8581, respectively, as reported by the Bank of Canada.

We reimburse our general partner for benefit and incentive compensation expenses based on a set formula, which expenses are attributable to additional compensation paid to each of them and other compensation and employment-related expenses, including TransCanada's restricted stock unit and stock option awards, retirement plans, health and welfare plans, employer-related payroll taxes, matching contributions made under a TransCanada's employee savings plan, and premiums for health and life insurance. This reimbursement is determined monthly and calculated based on total monthly base salary allocated to us multiplied by a factor of .38 for benefits and a factor of .30 for incentive compensation. The total amount reimbursed for benefits and incentive compensation were $334,678 in 2006 and $548,665 in 2007.

Director Compensation

Each director who is not an employee of TransCanada, the general partner or its affiliates (independent director) is entitled to a directors' retainer fee of $20,000 per annum. The independent director appointed as Lead Director and chair of the Conflicts Committee is entitled to an additional fee of $6,000 per annum, while the independent director appointed as chair of the Audit Committee is entitled to an additional fee of $4,000 per annum. These fees are paid by the Partnership on a semi-annual basis. Each independent director is also paid a fee of $1,500 for attendance at each meeting of the Board of Directors and a fee of $1,500 for attendance at each meeting of a committee of the Board. The independent directors are reimbursed for out-of-pocket expenses incurred in the course of attending such meetings.

Director Compensation Table

Name	Fees Earned or Paid in Cash	Total
David L. Marshall	60,000	60,000
Jack F. Jenkins-Stark	64,500	64,500
Walentin (Val) Mirosh	53,000	53,000

In October 2007, a revised compensation plan was approved for independent directors. Effective January 1, 2008, the directors' retainer fee was increased to $30,000 per annum from $20,000 per annum and directors will receive an annual grant of Partnership units under the Deferred Share Unit (DSU) Plan with a value of $20,000, as an equity

component of the annual retainer. No adjustments were made to meeting attendance fees or retainers for the Lead Director and chair of Conflicts Committee or chair of Audit Committee.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The following table sets forth the beneficial ownership of the voting securities of the Partnership as of February 25, 2008 by the general partner's directors, officers and certain beneficial owners. Executive officers of the general partner own shares of TransCanada, which in the aggregate amount to less than one per cent of TransCanada's issued and outstanding shares. Other than as set forth below, no person is known by the general partner to own beneficially more than five per cent of the voting securities of the Partnership.

	Amount and Nature of Beneficial Ownership		
Name and Business Address	Number of Common Units[1]	Number of DSUs[2]	Per cent of Class[3]
TransCan Northern Ltd. [4] 450 1st Street SW Calgary, Alberta T2P 5H1	8,678,045	—	24.9
TC Pipelines GP, Inc. [5] [6] 450 1st Street SW Calgary, Alberta T2P 5H1	2,035,106	—	5.8
David L. Marshall [7] 450 1st Street SW Calgary, Alberta T2P 5H1	450	550	*
Walentin (Val) Mirosh [8] 10th Floor, 1000-7th Avenue SW Calgary, Alberta T2P 5L5	—	550	*
Jack F. Jenkins-Stark [9] 1999 Harrison Street, Suite 500 Oakland, CA 94612	4,933	550	*
Gregory A. Lohnes 450 1st Street SW Calgary, Alberta T2P 5H1	—	—	—
Steven D. Becker 450 1st Street SW Calgary, Alberta T2P 5H1	—	—	—
Russell K. Girling 450 1st Street SW Calgary, Alberta T2P 5H1	6,000	—	*
Kristine L. Delkus 450 1st Street SW Calgary, Alberta T2P 5H1	—	—	—
Directors and Executive officers as a Group [10] [11] (12 persons)	—	—	*

(1) A total of 34,856,086 common units are issued and outstanding.

(2) A deferred share unit is a bookkeeping entry, equivalent to the value of a TC Pipelines common unit, and does not entitle the holder to voting or other shareholder rights, other than the accrual of additional deferred share units for the value of dividends. A director cannot redeem deferred share units until the director ceases to be a member of the Board. Directors can then redeem their units for cash or shares.

(3) Any deferred share units shall be deemed to be outstanding for the purpose of computing the percentage of outstanding common units owned by such person, but shall not be deemed to be outstanding for the purpose of computing the percentage of common units by any other person.

(4) TransCan Northern Ltd. is a wholly-owned indirect subsidiary of TransCanada.

(5) TC PipeLines GP, Inc. is a wholly-owned indirect subsidiary of TransCanada.

(6) TC PipeLines GP, Inc. owns an aggregate of two per cent general partner interest of TC PipeLines.

(7) 450 common units are held directly by Mr. Marshall.

(8) No common units are currently held by Mr. Mirosh.

(9) 4,933 common units are held by the Jenkins-Stark Family Trust dated June 16, 1995.

(10) With the exception of the two named directors above and Russell K. Girling, none of the other directors and executive officers hold any common units of TC PipeLines.

(11) Walentin (Val) Mirosh holds 726 shares of TransCanada, Russell K. Girling holds 394,108 options and 13,674 shares of TransCanada; Kristine L. Delkus holds 91,784 options and 3,874 shares of TransCanda; Steven D. Becker holds 103,275 options and 2,620 shares of TransCanada; Terry C. Ofremchuk holds 6,750 options and 5,216 shares of TransCanada; Gregory A. Lohnes holds 48,497 options and 9,880 shares of TransCanada; Amy W. Leong holds 5,600 options and 3,327 shares of TransCanada; Donald J. DeGrandis holds 17,300 options and 528 shares of TransCanada; Mark A.P. Zimmerman holds 20,413 options and 380 shares of TransCanada and Sean M. Brett holds 15,500 options of TransCanada, 9,713 shares of TransCanada and 500 Series U preferred shares of TransCanada PipeLines Limited, a wholly-owned subsidiary of TransCanada. The directors and executive officers as a group hold 703,227 options of TransCanada, 49,938 shares of TransCanada and 500 Series U preferred shares of TransCanada PipeLines Limited. All options listed above are exercisable within 60 days from February 28, 2008.

* Less than one per cent.

Item 13. Certain Relationships and Related Transactions, and Director Independence

At February 28, 2008, TransCan Northern owns 8,678,045 common units and the Partnership's general partner owns 2,035,106 common units, representing an aggregate 30.1 per cent limited partner interest in the Partnership. In addition, the general partner owns an aggregate two per cent general partner interest in the Partnership through which it manages and operates the Partnership. As a result, TransCanada's aggregate ownership interest in the Partnership is 32.1 per cent by virtue of its indirect ownership of the general partner and 30.1 per cent aggregate limited partner interest.

The general partner is accountable to TC PipeLines and the unitholders as a fiduciary. Neither the Delaware Revised Uniform Limited Partnership Act (Delaware Act) nor case law defines with particularity the fiduciary duties owed by general partners to limited partners of a limited partnership. The Delaware Act does provide that Delaware limited partnerships may, in their partnership agreements, restrict or expand the fiduciary duties owed by a general partner to limited partners and the partnership.

In order to induce the general partner to manage the business of TC PipeLines, the partnership agreement contains various provisions restricting the fiduciary duties that might otherwise be owed by the general partner. The following is a summary of the material restrictions of the fiduciary duties owed by the general partner to the limited partners:

- The partnership agreement permits the general partner to make a number of decisions in its "sole discretion." This entitles the general partner to consider only the interests and factors that it desires and it shall have no duty or obligation to give any consideration to any interest of, or factors affecting, TC PipeLines, its affiliates or any limited partner. Other provisions of the partnership agreement provide that the general partner's actions must be made in its reasonable discretion.
- The partnership agreement generally provides that affiliated transactions and resolutions of conflicts of interest not involving a required vote of unitholders must be "fair and reasonable" to TC PipeLines. In determining whether a transaction or resolution is "fair and reasonable" the general partner may consider

interests of all parties involved, including its own. Unless the general partner has acted in bad faith, the action taken by the general partner shall not constitute a breach of its fiduciary duty.
- The partnership agreement specifically provides that it shall not be a breach of the general partner's fiduciary duty if its affiliates engage in business interests and activities in competition with, or in preference or to the exclusion of, TC PipeLines. Further, the general partner and its affiliates have no obligation to present business opportunities to TC PipeLines.
- The partnership agreement provides that the general partner and its officers and directors will not be liable for monetary damages to TC PipeLines, the limited partners or assignees for errors of judgment or for any acts or omissions if the general partner and those other persons acted in good faith.

TC PipeLines is required to indemnify the general partner and its officers, directors, employees, affiliates, partners, members, agents and trustees (collectively referred to hereafter as the General Partner and others), to the fullest extent permitted by law, against liabilities, costs and expenses incurred by the General Partner and others. This indemnification is required if the General Partner and others acted in good faith and in a manner they reasonably believed to be in, or (in the case of a person other than the general partner) not opposed to, the best interests of TC PipeLines. Indemnification is required for criminal proceedings if the General Partner and others had no reasonable cause to believe their conduct was unlawful.

The Partnership does not have any employees. The management and operating functions are provided by the general partner. The general partner does not receive a management fee or other compensation in connection with its management of the Partnership. The Partnership reimburses the general partner for all costs of services provided, including the costs of employee, officer and director compensation and benefits, and all other expenses necessary or appropriate to the conduct of the business of, and allocable to, the Partnership. Such costs include (i) overhead costs (such as office space and equipment) and (ii) out-of-pocket expenses related to the provision of such services. The Partnership Agreement provides that the general partner will determine the costs that are allocable to the Partnership in any reasonable manner determined by the general partner in its sole discretion. Total costs charged to the Partnership by the general partner were $1.9 million for the year ended December 31, 2007.

Pursuant to our Partnership agreement, whenever a potential conflict of interest exists or arises between the general partner or any of its affiliates and the Partnership, any resolution or course of action by the general partner or its affiliates in respect of such conflict of interest shall be permitted if the resolution or course of action is deemed to be fair and reasonable to the Partnership. As such, the general partner has established a Conflicts Committee, of not less than two independent directors, to oversee all matters relating to the resolution of conflicts of interest and to provide to our Board of Directors recommendation for such resolution of conflicts of interest.

On February 22, 2007, the Partnership acquired a 46.45 per cent general partner interest in Great Lakes from El Paso Corporation. The acquisition was partially financed through a private placement of common units for gross proceeds of $600.0 million which closed concurrently with the acquisition. TransCan Northern purchased 8,678,045 of the 17,356,086 common units issued for gross proceeds of $300 million. In addition, TC PipeLines GP maintained its two per cent general partner interest in the Partnership by contributing $12.6 million to the Partnership in connection with the private placement. TransCanada, which previously held a 50 per cent interest in Great Lakes, acquired the other 3.55 per cent interest simultaneously with the Partnership's acquisition of its interest. A wholly-owned subsidiary of TransCanada became the operator of Great Lakes through TransCanada's acquisition of Great Lakes Gas Transmission Company.

TCNB became the operator of Northern Border effective April 1, 2007. On December 19, 2006, the Partnership acquired an additional 49 per cent general partner interest in Tuscarora. In connection with this transaction, TCNB became the operator of Tuscarora. TransCanada and its affiliates provide capital and operating services to our pipeline systems. TransCanada and its affiliates also incur costs on behalf of our pipeline systems, including, but not limited to, employee benefit costs, property and liability insurance costs, and transition costs. Total costs charged to our pipeline systems in 2007 by TransCanada and its affiliates and amounts owed to TransCanada and its affiliates at December 31, 2007 are summarized in the following table:

(millions of dollars)	Great Lakes	Northern Border	Tuscarora
Costs charged by TransCanada and its affiliates	25.6	22.5	1.8
Impact on the Partnership's net income	11.2	11.0	0.9
Amount owed to TransCanada and its affiliates	1.9	3.0	3.5

Great Lakes earns transportation revenues from TransCanada and its affiliates under fixed priced contracts with remaining terms ranging from one to ten years. Great Lakes earned $113.9 million of transportation revenues under these contracts for the period February 23, 2007 to December 31, 2007. This amount represents 48.2 per cent of total revenues earned by Great Lakes for the period February 23, 2007 to December 31, 2007. $52.9 million of transportation revenue is included in the Partnership's equity income from Great Lakes during the same period. At December 31, 2007, $10.0 million is included in Great Lakes' receivables in regards to the transportation contracts with TransCanada and its affiliates.

For the year ended December 31, 2007, the Partnership recorded transmission revenues of $19.4 million in regards to various contracts with Sierra Pacific Power Company, a wholly-owned subsidiary of Sierra Pacific Resources.

On May 8, 2007, the Partnership reimbursed TransCanada $2.8 million for third party costs related to the Partnership's acquisition of its interest in Great Lakes. On September 26, 2007, the Partnership reimbursed TransCanada $1.2 million for a working capital adjustment related to the Partnership's acquisition of its interest in Great Lakes.

On December 31, 2007, the Partnership acquired a one per cent general partner interest in Tuscarora from a wholly-owned subsidiary of TransCanada for $2.0 million. The purchase price of this acquisition was derived from the formula used to calculate the purchase price of a different one per cent general partner interest in Tuscarora which was purchased from Tuscarora Gas Pipeline Co, a wholly-owned subsidiary of Sierra Pacific Resources on the same day.

Item 14. Principal Accounting Fees and Services

The following table sets forth, for the periods indicated, the fees billed by the principal accountants.

	2007	2006
Audit Fees [(1)]	**310,745**	217,803
Audit Related Fees [(2)]	**170,014**	26,500

Tax Fees [3]	—	—
All Other Fees [3]	—	—

[(1)] Audit Fees include services performed related to Sarbanes-Oxley Act reporting requirements.

[(2)] The increase in Audit Related Fees is primarily due to prospectus work in connection with the Great Lakes acquisition.

[(3)] The Partnership has not engaged its external auditors for any tax or other services in 2007 or 2006.

AUDIT FEES

Audit fees include fees for the audit of annual GAAP financial statements, reviews of the related quarterly financial statements and related consents and comforts letters for documents filed with the SEC. Before our independent principal accountant is engaged each year for annual audit and other audit and any non-audit services, these services and fees are reviewed and approved by our Audit Committee.

PART IV

Item 15. Exhibits, Financial Statement Schedules

a) (1) and (2) Financial Statements and Financial Statement Schedules
The financial statements filed as part of this report are listed in the "Index to Financial Statements" on page F-1.
(3) Exhibits

No.	Description
*+2.1	Partnership Interest Purchase and Sale Agreement dated as of December 31, 2005 by and between Northern Border Intermediate Limited Partnership and TC PipeLines Intermediate Limited Partnership (Exhibit 2.1 to TC PipeLines, LP's Form 8-K filed on February 15, 2006 (File No. 000-26091)).
*+2.2	General Partnership Interest Purchase Agreement dated as of November 1, 2006 by and between Tuscarora Gas Pipeline Co. and TC Tuscarora Intermediate Limited Partnership (Exhibit 2.1 to TC PipeLines, LP's Form 8-K filed on November 7, 2006 (File No. 000-26091)).
*+2.3	General Partner Interest Holder Agreement dated as of November 1, 2006 by and between Tuscarora Gas Pipeline Co. and TC Tuscarora Intermediate Limited Partnership (Exhibit 2.2 to TC PipeLines, LP's Form 8-K filed on November 7, 2006 (File No. 000-26091)).
*+2.4	Purchase and Sale Agreement among El Paso Great Lakes Company, L.C.C., as Seller, and TC GL Intermediate Limited Partnership and TransCanada PipeLine USA Ltd., as Buyers dated as of December 22, 2006 (Exhibit 2.1 to TC PipeLines, LP's Form 8-K filed on December 26, 2006 (File No. 000-26091)).
2.5	General Partnership Interest Purchase Agreement dated as of December 20, 2007 by and between TCPL Tuscarora Ltd. and TC Pipelines Tuscarora LLC.
*3.1	Amended and Restated Agreement of Limited Partnership of TC PipeLines, LP dated May 28, 1999 (Exhibit 3.1 to TC PipeLines, LP's Form 10-K filed on March 28, 2000 (File No. 333-69947)).
3.1.1	Amendment to the Amended and Restated Agreement of Limited Partnership of TC PipeLines, LP dated November 19, 2007.
*3.2	Certificate of Limited Partnership of TC PipeLines, LP (Exhibit 3.2 to TC PipeLines, LP's Form S-1 Registration Statement, Registration No. 333-69947 filed on December 30, 1998).
*4.1	Indenture, dated as of August 17, 1999 between Northern Border Pipeline Company and Bank One Trust Company, NA, successor to The First National Bank of Chicago, Trustee (Exhibit 4.1 to Northern Border Pipeline Company's Form S-4 Registration Statement, Registration No. 333-88577 filed on October 7, 1999).
*4.2	Indenture, Assignment and Security Agreement dated December 21, 1995 between Tuscarora Gas Transmission Company and Wilmington Trust Company, as trustee (Exhibit 99.1 to TC PipeLines, LP's Form 10-Q filed on November 13, 2000 (File No.333-69947)).
*4.3	Indenture dated September 17, 2001, between Northern Border Pipeline Company and Bank One Trust Company, N.A., Trustee (Exhibit 4.2 to Northern Border Pipeline Company's Form S-4 Registration Statement, Registration No. 333-73282 filed on November 13, 2001).
*4.4	Registration Rights Agreement between TC PipeLines, LP, TransCan Northern Ltd., Kayne Anderson MLP Investment Company, Kayne Anderson Energy Total Return Fund, Inc., Kayne Anderson MLP Fund, L.P., Kayne Anderson Capital Income Partners (QP), L.P., Strome MLP Fund, LP, Royal Bank of Canada, Tortoise Energy Infrastructure Corporation, Tortoise Energy Capital Corporation, Tortoise North American Energy Corporation, GPS Income Fund LP, GPS High Yield Equities Fund, HFR RVAGPS Master Trust, GPS New Equity Fund LP, TPG-Axon Partners, LP, Lehman Brothers Inc., Structured Finance Americas, LLC, The Cushing MLP Opportunity Fund I, LP, Swank MLP Convergence Fund, LP, and Citigroup Global Markets, Inc.

	dated February 22, 2007 (Exhibit 4.1 to TC PipeLines, LP's Form 8-K filed on February 23, 2007 (File No. 000-26091)).
*10.1	Contribution, Conveyance and Assumption Agreement among TC PipeLines, LP and certain other parties dated May 28, 1999 (Exhibit 10.2 to TC PipeLines, LP's Form 10-K filed on March 28, 2000 (File No. 333-69947)).
*10.2	First Amended and Restated General Partnership Agreement of Northern Border Pipeline Company dated April 6, 2006, by and between Northern Border Intermediate Limited Partnership and TC Pipelines Intermediate Limited Partnership (Exhibit 3.1 to Northern Border Pipeline Company's Form 8-K filed on April 12, 2006 (File No. 333-87753)).
*10.3	Revolving Credit Agreement, dated as of April 27, 2007, among Northern Border Pipeline Company, the lenders from time to time party thereto, SunTrust Bank, as Administrative Agent, Wachovia Bank National Association, as Syndication Agent, BMO Capital Markets, Citibank, N.A. and Mizuho Corporate Bank, LTD., as Co-Documentation Agents, JP Morgan Chase Bank, N.A. and Export Development Canada, as Managing Agents and Wachovia Capital Markets, LLC and SunTrust Capital Markets, Inc., as Co-Lead Arrangers and Book Managers. (Exhibit 10.1 to Northern Border Pipeline Company's Form 10-Q filed on April 30, 2007 (File No. 333-88577)).
*10.4	Amended and Restated Revolving Credit and Term Loan Agreement among TC PipeLines, LP, the lenders from time to time party thereto, SunTrust Bank as Administrative Agent, UBS Securities LLC and Royal Bank of Canada, as Co-Documentation Agents, BMO Capital Markets Financing Inc. and the Royal Bank of Scotland PLC, as Co-Syndication Agents, Deutsche Bank AG New York Branch and the Bank of Tokyo-Mitsubishi UFJ, Ltd., as Managing Agents, and SunTrust Capital Markets, Inc. as Arranger and Book Manager, dated February 13, 2007 (Exhibit 10.1 to TC PipeLines, LP's Form 8-K filed on February 15, 2007 (File No. 000-26091)).
*10.5	Subordinated Loan Agreement between TC PipeLines, LP and TransCanada PipeLines Limited, dated February 13, 2007 (Exhibit 10.2 to TC PipeLines, LP's Form 8-K filed on February 15, 2007 (File No. 000-26091)).
*10.6	Subordination and Intercreditor Agreement among TransCanada PipeLines Limited, TC PipeLines, LP, and SunTrust Bank, as Administrative Agent, dated February 13, 2007 (Exhibit 10.3 to TC PipeLines, LP's Form 8-K filed on February 15, 2007 (File No. 000-26091)).
*10.7	Common Unit Purchase Agreement by and among TC PipeLines, LP and TransCan Northern Ltd., Kayne Anderson MLP Investment Company, Kayne Anderson Energy Total Return Fund, Inc., Kayne Anderson MLP Fund, L.P., Kayne Anderson Capital Income Partners (QP), L.P., Strome MLP Fund, LP, Royal Bank of Canada, Tortoise Energy Infrastructure Corporation, Tortoise Energy Capital Corporation, Tortoise North American Energy Corporation, GPS Income Fund LP, GPS High Yield Equities Fund, HFR RVAGPS Master Trust, GPS New Equity Fund LP, TPG-Axon Partners, LP, Lehman Brothers Inc., Structured Finance Americas, LLC, The Cushing MLP Opportunity Fund I, LP, Swank MLP Convergence Fund, LP, and Citigroup Global Markets, Inc. dated February 22, 2007 (Exhibit 10.1 to TC PipeLines, LP's Form 8-K filed on February 23, 2007 (File No. 000-26091)).
*10.8	Form of Conveyance, Contribution and Assumption Agreement among Northern Plains Natural Gas Company, Northwest Border Pipeline Company, Pan Border Gas Company, Northern Border Partners, L.P., and Northern Border Intermediate Limited Partnership. (Exhibit 10.16 to Northern Border Pipeline Company's Form S-1 Registration Statement filed on July 16, 1993 (Registration No. 33-66158)).
*10.9	Form of Contribution, Conveyance and Assumption Agreement among TC PipeLines, L.P., and Northern Border Intermediate Limited Partnership. (Exhibit 10.2 to TC PipeLines, LP's Form S-1/A filed on May 3, 1999 (File No. 333-69947)).
*10.10	Operating Agreement by and between Northern Border Pipeline Company and TransCan Northwest Border Ltd. (Exhibit 10.2 to Northern Border Pipeline Company's Form 8-K filed on April 12, 2006 (File No. 333-88577)).
*10.11	Operating Agreement by and between Tuscarora Gas Transmission Company and TransCan Northwest Border Ltd. dated as of December 19, 2006 (Exhibit 10.11 to TC PipeLines, LP's Form 10-Kfiled on March 2, 2007 (File No. 000-26091)).
*10.12	Transportation Service Agreement FT4760 between Great Lakes Gas Transmission Limited Partnership and TransCanada PipeLines Limited, dated November 30, 2006. (Exhibit 10.1 to TC PipeLines, LP's Form 10-Q filed on April 30, 2007 (File No. 000-26091)).

*10.13	Transportation Service Agreement FT4761 between Great Lakes Gas Transmission Limited Partnership and TransCanada PipeLines Limited, dated November 4, 2004. (Exhibit 10.2 to TC PipeLines, LP's Form 10-Q filed on April 30, 2007 (File No. 000-26091)).
*10.14	Transportation Service Agreement FT4762 between Great Lakes Gas Transmission Limited Partnership and TransCanada PipeLines Limited, dated November 4, 2004. (Exhibit 10.3 to TC PipeLines, LP's Form 10-Q filed on April 30, 2007 (File No. 000-26091)).
*10.15	Transportation Service Agreement FT4763 between Great Lakes Gas Transmission Limited Partnership and TransCanada PipeLines Limited, dated November 4, 2004. (Exhibit 10.4 to TC PipeLines, LP's Form 10-Q filed on April 30, 2007 (File No. 000-26091)).
*10.16	Transportation Service Agreement FT4764 between Great Lakes Gas Transmission Limited Partnership and TransCanada PipeLines Limited, dated November 30, 2006. (Exhibit 10.5 to TC PipeLines, LP's Form 10-Q filed on April 30, 2007 (File No. 000-26091)).
*10.17	Transportation Service Agreement FT5840 between Great Lakes Gas Transmission Limited Partnership and TransCanada PipeLines Limited, dated December 1, 2005. (Exhibit 10.6 to TC PipeLines, LP's Form 10-Q filed on April 30, 2007 (File No. 000-26091)).
*10.18	Transportation Service Agreement FT5841 between Great Lakes Gas Transmission Limited Partnership and TransCanada PipeLines Limited, dated December 1, 2005. (Exhibit 10.7 to TC PipeLines, LP's Form 10-Q filed on April 30, 2007 (File No. 000-26091)).
*10.19	Transportation Service Agreement FT5842 between Great Lakes Gas Transmission Limited Partnership and TransCanada PipeLines Limited, dated November 30, 2006. (Exhibit 10.8 to TC PipeLines, LP's Form 10-Q filed on April 30, 2007 (File No. 000-26091)).
10.20	Transportation Service Agreement FT4760 between Great Lakes Gas Transmission Limited Partnership and TransCanada Pipelines Limited, dated December 7, 2007.
10.21	Transportation Service Agreement FT8742 between Great Lakes Gas Transmission Limited Partnership and TransCanada Pipelines Limited, dated December 6, 2007.
*10.22	Amended and Restated Agreement of Limited Partnership of Great Lakes Gas Transmission Limited Partnership between TransCanada GL, Inc., TC GL Intermediate Limited Partnership and Great Lakes Gas Transmission Company, dated February 22, 2007. (Exhibit 10.9 to TC PipeLines, LP's Form 10-Q filed on April 30, 2007 (File No. 000-26091)).
*10.23	Operating Agreement between Great Lakes Gas Transmission Limited Partnership and Great Lakes Gas Transmission Company, dated April 5, 1990. (Exhibit 10.10 to TC PipeLines, LP's Form 10-Q filed on April 30, 2007 (File No. 000-26091)).
#10.24	The TC PipeLines GP, Inc. Share Unit Plan for Non-Employee Directors (2007), dated October 18, 2007.

21.1	Subsidiaries of the Registrant.
23.1	Consent of KPMG LLP with respect to the financial statements of TC PipeLines, LP
23.2	Consent of KPMG LLP with respect to the financial statements of Great Lakes Gas Transmission Limited Partnership
23.3	Consent of KPMG LLP with respect to the financial statements of Northern Border Pipeline Company
31.1	Certification of Principal Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Principal Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of Principal Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Principal Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*99.1	Consolidated Balance Sheets of TC PipeLines GP, Inc. as of December 31, 2006 and 2005. (Exhibit 99.1 to TC PipeLines, LP's Form 10-Q filed on April 30, 2007 (File No. 000-26091)).

* Indicates exhibits incorporated by reference.
+ Pursuant to item 601(b)(2) of Regulation S-K, the registrant agrees to furnish supplementally a copy of any omitted exhibit or schedule to the SEC upon request.
# Management contract or compensatory plan or arrangement.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on this 28th day of February 2008.

TC PIPELINES, LP
(A Delaware Limited Partnership)
by its general partner, TC PipeLines GP, Inc.

By: /s/ Russell K. Girling

Russell K. Girling
Chairman, Chief Executive Officer and Director
TC PipeLines GP, Inc. (Principal Executive Officer)

By: /s/ Amy W. Leong

Amy W. Leong
Controller
TC PipeLines GP, Inc. (Principal Financial Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Russell K. Girling Russell K. Girling	Chairman, Chief Executive Officer and Director (Principal Executive Officer)	February 28, 2008
/s/ Amy W. Leong Amy W. Leong	Controller and Principal Financial Officer	February 28, 2008
/s/ Gregory A. Lohnes Gregory A. Lohnes	Director	February 28, 2008
/s/ Kristine L. Delkus Kristine L. Delkus	Director	February 28, 2008
/s/ Steven D. Becker Steven D. Becker	Director	February 28, 2008
/s/ Walentin (Val) Mirosh Walentin (Val) Mirosh	Director	February 28, 2008
/s/ Jack F. Jenkins-Stark Jack F. Jenkins-Stark	Director	February 28, 2008

/s/ David L. Marshall David L. Marshall	Director	February 28, 2008

TC PIPELINES, LP

INDEX TO FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors of TC PipeLines GP, Inc., General Partner of TC PipeLines, LP:

We have audited the accompanying consolidated balance sheets TC PipeLines, LP (a Delaware limited partnership) and subsidiaries as of December 31, 2007 and 2006, and the related consolidated statements of income, comprehensive income, cash flows and changes in partners' equity for each of the years in the three-year period ended December 31, 2007. These consolidated financial statements are the responsibility of the General Partner's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of TC PipeLines, LP and subsidiaries as of December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2007, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), TC PipeLines, LP's internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 27, 2008 expressed an unqualified opinion on the effectiveness of the Partnership's internal control over financial reporting.

/s/ KPMG LLP

Calgary, Canada
February 27, 2008

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors of TC PipeLines GP, Inc., General Partner of TC PipeLines, LP:

We have audited TC PipeLines, LP's internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Management of the General Partner of TC PipeLines, LP is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Controls over Financial Reporting. Our responsibility is to express an opinion on the Partnership's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

An entity's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. An entity's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the entity; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the entity are being made only in accordance with authorizations of management and directors of the entity; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the entity's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, TC PipeLines, LP maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of TC PipeLines, LP as of December 31, 2007 and 2006, and the related consolidated statements of income, comprehensive income, cash flows and changes in partners' equity for each of the years in the three-year period ended December 31, 2007, and our report dated February 27, 2008 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Calgary, Canada
February 27, 2008

TC PIPELINES, LP
CONSOLIDATED BALANCE SHEET

December 31 (millions of dollars)	2007	2006
Assets		
Current Assets		
Cash and short-term investments	**6.8**	4.0
Accounts receivable and other	**4.2**	2.5
	11.0	6.5
Investment in Great Lakes *(Note 3)*	**721.1**	—
Investment in Northern Border *(Note 4)*	**541.9**	561.2
Plant, property and equipment *(Note 6)*	**134.1**	127.0
Goodwill *(Note 7)*	**81.7**	79.2
Other assets	**2.8**	3.9
	1,492.6	777.8
Liabilities and Partners' Equity		
Current Liabilities		

Bank indebtedness	**1.4**	—
Accounts payable	**4.8**	3.3
Accrued interest	**3.0**	1.3
Current portion of long-term debt *(Note 8)*	**4.6**	4.7
	13.8	9.3
Hedging deferrals	**9.9**	—
Long-term debt *(Note 8)*	**568.8**	463.4
	592.5	472.7
Non-controlling interests *(Note 5)*	**—**	1.2
Partners' Equity *(Note 9)*		
Common units	**892.3**	295.6
General partner	**19.1**	6.5
Accumulated other comprehensive (loss)/income	**(11.3)**	1.8
	900.1	303.9
	1,492.6	777.8

Subsequent events *(Note 18)*

The accompanying notes are an integral part of these consolidated financial statements.

TC PIPELINES, LP
CONSOLIDATED STATEMENT OF INCOME

Year ended December 31 (millions of dollars except per common unit amounts)	2007	2006	2005
Equity income from investment in Great Lakes *(Note 3)*	**49.0**	—	—
Equity income from investment in Northern Border *(Note 4)*	**61.2**	56.6	45.7
Equity income from investment in Tuscarora *(Note 5)*	**—**	5.9	7.5
Transmission revenues	**27.2**	0.9	—
Operating expenses	**(8.3)**	(2.7)	(2.0)
Depreciation	**(6.3)**	(0.2)	—
Financial charges, net and other *(Note 10)*	**(33.8)**	(15.8)	(1.0)
Net income	**89.0**	44.7	50.2
Net income per common unit *(Note 11)*	**$ 2.51**	$ 2.39	$ 2.70
Common units outstanding, end of the year *(millions)*	**34.9**	17.5	17.5

TC PIPELINES, LP
CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

Year ended December 31 (millions of dollars)	2007	2006	2005
Net income	**89.0**	44.7	50.2
Other comprehensive (loss)/income			
Change associated with current period hedging transactions *(Note 16)*	**(11.4)**	1.6	—
Change associated with current period hedging transactions of investees	**(1.7)**	(0.5)	(0.5)
	(13.1)	1.1	(0.5)
Total comprehensive income	**75.9**	45.8	49.7

The accompanying notes are an integral part of these consolidated financial statements.

TC PIPELINES, LP
CONSOLIDATED STATEMENT OF CASH FLOWS

Year ended December 31 (millions of dollars)	2007	2006	2005
Cash Generated From Operations			
Net income	**89.0**	44.7	50.2
Depreciation	**6.3**	0.2	—
Amortization of other assets *(Note 10)*	**0.4**	0.9	—
Non-controlling interests *(Note 5)*	**0.2**	—	—
Equity allowance for funds used during construction	**(0.2)**	—	—

Decrease/(increase) in operating working capital	**2.9**	0.3	(0.1)
	98.6	46.1	50.1
Investing Activities			
Return of capital from Great Lakes	**12.3**	—	—
Return of capital from Northern Border	**25.1**	23.8	15.2
Return of capital from Tuscarora	—	1.8	0.8
Investment in Great Lakes *(Note 3)*	**(733.0)**	—	—
Investment in Northern Border *(Note 4)*	**(7.5)**	(311.1)	—
Investment in Tuscarora, net of cash acquired *(Notes 5 and 7)*	**(3.9)**	(97.2)	(0.3)
Increase in cash due to the consolidation of Tuscarora *(Note 7)*	—	2.6	—
Capital expenditures	**(13.2)**	—	—
Other assets	**(1.2)**	(1.9)	—
	(721.4)	(382.0)	15.7
Financing Activities			
Distributions paid *(Note 12)*	**(86.7)**	(43.5)	(43.0)
Equity issuances, net	**607.0**	—	—
Long-term debt issued *(Note 8)*	**171.5**	707.0	—
Long-term debt repaid *(Note 8)*	**(66.2)**	(325.9)	(23.0)
	625.6	337.6	(66.0)
Increase/(decrease) in cash and short-term investments	**2.8**	1.7	(0.2)
Cash and short-term investments, beginning of year	**4.0**	2.3	2.5
Cash and short-term investments, end of year	**6.8**	4.0	2.3
Interest payments made	**34.3**	13.9	1.0

The accompanying notes are an integral part of these consolidated financial statements.

TC PIPELINES, LP
CONSOLIDATED STATEMENT OF CHANGES IN PARTNERS' EQUITY

	Common Units		General Partner	Accumulated Other Comprehensive Income/(Loss)	Partners' Equity	
	(millions of units)	(millions of dollars)	(millions of dollars)	(millions of dollars)	(millions of units)	(millions of dollars)
Partners' equity at December 31, 2004	17.5	287.4	6.3	1.2	17.5	294.9
Net income	—	47.3	2.9	—	—	50.2
Distributions paid	—	(40.3)	(2.7)	—	—	(43.0)
Other comprehensive loss	—	—	—	(0.5)	—	(0.5)
Partners' equity at December 31, 2005	17.5	294.4	6.5	0.7	17.5	301.6
Net income	—	41.8	2.9	—	—	44.7
Distributions paid	—	(40.6)	(2.9)	—	—	(43.5)
Other comprehensive income	—	—	—	1.1	—	1.1
Partners' equity at December 31, 2006	17.5	295.6	6.5	1.8	17.5	303.9
Net income	—	81.3	7.7	—	—	89.0
Equity issuances, net	17.4	594.4	12.6	—	17.4	607.0
Distributions paid	—	(79.0)	(7.7)	—	—	(86.7)
Other comprehensive loss	—	—	—	(13.1)	—	(13.1)
Partners' equity at December 31, 2007	**34.9**	**892.3**	**19.1**	**(11.3)**	**34.9**	**900.1**

The accompanying notes are an integral part of these consolidated financial statements.

TC PIPELINES, LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 ORGANIZATION

TC PipeLines, LP and its subsidiary limited partnerships and limited liability company, including TC PipeLines Intermediate Limited Partnership, TC Tuscarora Intermediate Limited Partnership and TC GL Intermediate Limited Partnership, all Delaware limited partnerships, and TC Pipelines

Tuscarora LLC, are collectively referred to herein as TC PipeLines or the Partnership. TC PipeLines was formed by TransCanada PipeLines Limited, a wholly-owned subsidiary of TransCanada Corporation (collectively referred to herein as TransCanada), to acquire, own and participate in the management of energy infrastructure assets in North America.

TC PipeLines, through TC GL Intermediate Limited Partnership, owns a 46.45 per cent general partner interest in Great Lakes Gas Transmission Limited Partnership (Great Lakes), a Delaware limited partnership. Great Lakes owns a 2,115-mile pipeline that transports natural gas serving markets in Minnesota, Wisconsin, Michigan and Eastern Canada.

TC PipeLines, through TC PipeLines Intermediate Limited Partnership, owns a 50 per cent general partner interest in Northern Border Pipeline Company (Northern Border), a Texas general partnership. Northern Border owns a 1,249-mile U.S. interstate pipeline system that transports natural gas from the Montana-Saskatchewan border to markets in the Midwestern U.S.

TC PipeLines also, through TC Tuscarora Intermediate Limited Partnership and TC Pipelines Tuscarora LLC, wholly-owns Tuscarora Gas Transmission Company (Tuscarora), a Nevada general partnership. Tuscarora owns a 240-mile U.S. interstate pipeline system that transports natural gas from Oregon, where it interconnects with facilities of Gas Transmission Northwest Corporation (GTN), a wholly-owned subsidiary of TransCanada, to Northern Nevada.

TC PipeLines is managed by its general partner, TC PipeLines GP, Inc. (TC PipeLines GP), a wholly-owned subsidiary of TransCanada. The general partner provides administrative services for the Partnership and is reimbursed for its costs and expenses. In addition to its aggregate two per cent general partner interest in TC PipeLines, on a combined basis, the general partner owns 2,035,106 common units, representing an effective 7.7 per cent limited partner interest in the Partnership at December 31, 2007. TransCanada also indirectly holds 8,678,045 common units representing an effective 24.4 per cent limited partner interest in the Partnership at December 31, 2007.

NOTE 2 SIGNIFICANT ACCOUNTING POLICIES

(a) Basis of Presentation

The accompanying financial statements and related notes present the financial position of the Partnership as of December 31, 2007 and 2006 and the results of its operations, cash flows and changes in partners' equity for the years ended December 31, 2007, 2006 and 2005. The Partnership uses the equity method of accounting for its investments in Great Lakes and Northern Border, over which it is able to exercise significant influence. TC PipeLines accounted for its investment in Tuscarora using the equity method until December 19, 2006. On this date, the Partnership acquired an additional 49 per cent general partner interest in Tuscarora and as a result of acquiring a controlling interest in Tuscarora, began to consolidate Tuscarora's operations. Amounts are stated in U.S. dollars. Certain comparative figures have been reclassified to conform to the current year's presentation.

(b) Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Although management believes these estimates are reasonable, actual results could differ from these estimates.

(c) Cash and Short-Term Investments

The Partnership's short-term investments with original maturities of three months or less are considered to be cash equivalents and are recorded at cost, which approximates market value.

(d) Plant, Property and Equipment

Plant, property and equipment relates solely to Tuscarora and is stated at original cost. Costs of restoring the land above and around the pipeline are capitalized to pipeline facilities and depreciated over the remaining life of the related pipeline facilities. Depreciation of pipeline facilities and compression equipment is provided on a straight-line composite basis over the estimated useful life of the pipeline of 30 years and of the compression equipment of 25 years. Metering and other is depreciated on a straight-line basis over the estimated useful lives of the equipment, which range from 3 to 30 years. Repair and maintenance costs are expensed as incurred. Costs that are considered a betterment are capitalized. An allowance for funds used during construction, using the rate of return on rate base approved by the Federal Energy Regulatory Commission (FERC), is capitalized and included in the cost of plant, property and equipment.

Long-lived assets are assessed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability is assessed by comparing the carrying amount of an asset to future net cash flows expected to be generated by the asset. If such assets are considered to be impaired, the impairment to be recognized is measured by the amount by which the carrying amounts of such assets exceed the fair value of the assets.

(e) Partners' Equity

Costs incurred in connection with the issuance of units are deducted from the proceeds received.

(f) Revenue Recognition

Transmission revenues are recognized in the period in which the service is provided. When rate cases are pending final FERC approval, a portion of revenue collected is subject to possible refund. As of December 31, 2007, the Partnership has not recognized any transmission revenue that is subject to refund.

(g) Income Taxes

As a partnership, TC PipeLines is not subject to Federal or state income tax. The tax effect of the Partnership's activities accrues to its partners. The Partnership's taxable income or loss, which may vary substantially from the net income or loss reported in the consolidated statement of income, is includable in the federal income tax returns of each partner. The aggregate difference in the basis of the Partnership's net assets for financial and income tax purposes cannot be readily determined because all information regarding each partner's tax attributes related to the partnership is not available.

(h) Acquisitions and Goodwill

The Partnership accounts for business acquisitions using the purchase method of accounting and accordingly the assets and liabilities of the acquired entities are recorded at their estimated fair values at the date of acquisition. The excess of the purchase price over the fair value of net assets acquired is attributed to goodwill. Goodwill is not amortized for accounting purposes; however, it is tested on an annual basis for impairment, or more frequently if any indicators of impairment are evident.

(i) Derivative Financial Instruments and Hedging Activities

The Partnership utilizes derivative and other financial instruments to manage its exposure to changes in interest rates. Derivatives and other instruments must be designated as hedges and be effective to qualify for hedge accounting. Derivatives are recorded at their fair value at each balance sheet date. For cash flow hedges, unrealized gains or losses relating to derivatives are recognized as other comprehensive income. In the event that a derivative does not meet the designation or effectiveness criteria, any unrealized gain or loss on the instrument is recognized immediately in earnings.

If a derivative that previously qualified as a hedge is settled, de-designated or ceases to be effective, the gain or loss at that date is deferred and recognized in the same period and in the same financial statement category as the corresponding hedged transactions. If a hedged anticipated transaction is no longer probable to occur, related gains or losses are immediately recognized in earnings and amounts previously recognized in other comprehensive income

are reclassified to earnings prospectively. Costs associated with the purchase of certain hedging instruments are deferred and amortized against interest expense.

(j) Asset Retirement Obligation

Statement of Financial Accounting Standards (SFAS) No. 143, *Accounting for Asset Retirement Obligations,* provides accounting requirements for the recognition and measurement of liabilities associated with the retirement of tangible long-lived assets. Under the standard, these liabilities are recognized at fair value as incurred and capitalized as part of the cost of the related tangible long-lived assets. Accretion of the liabilities due to the passage of time is classified as an operating expense. Retirement obligations associated with long-lived assets included within the scope of SFAS No. 143 are those for which a legal obligation exists under enacted laws, statutes, ordinances, or written or oral contracts, including obligations arising under the doctrine of promissory estoppel.

FIN 47, *Accounting for Conditional Asset Retirement Obligations – an interpretation of SFAS No. 143,* clarifies the term "conditional asset retirement obligation," as used in SFAS No. 143 and the circumstances under which an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation. No amount is recorded for asset retirement obligations relating to the assets as it is not possible to make a reasonable estimate of the fair value of the liability due to the inability to determine the scope and timing of the asset retirements. Management believes it is reasonable to assume that all retirement costs associated with the pipeline system will be recovered through rates in future periods.

(k) Government Regulation

Tuscarora, our wholly-owned pipeline system, is subject to regulation by the FERC. The Partnership's accounting policies conform to SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation.* Accordingly, certain assets or liabilities that result from the regulated ratemaking process are recorded that would not be recorded under generally accepted accounting principles for non-regulated entities. The Partnership regularly evaluates the continued applicability of SFAS No. 71, considering such factors as regulatory changes, the impact of competition, and the ability to recover regulatory assets. As of December 31, 2007 and 2006, the Partnership has no regulatory assets or liabilities.

NOTE 3 INVESTMENT IN GREAT LAKES

On February 22, 2007, the Partnership acquired a 46.45 per cent general partner interest in Great Lakes. TransCanada, which previously held a 50 per cent interest in Great Lakes, acquired the other 3.55 per cent interest concurrent with the Partnership's acquisition of its interest. Effective February 22, 2007, a wholly-owned subsidiary of TransCanada became the operator of Great Lakes. Great Lakes is regulated by the FERC.

TC GL Intermediate Limited Partnership, as one of the general partners, may be exposed to the commitments and contingencies of Great Lakes. TC PipeLines, LP holds a 98.9899 per cent limited partnership interest in TC GL Intermediate Limited Partnership.

The Partnership uses the equity method of accounting for its investment in Great Lakes. TC PipeLines' equity income from its investment in Great Lakes amounted to $49.0 million for the period February 23, 2007 to December 31, 2007. Great Lakes had no undistributed earnings for the year ended December 31, 2007.

The following sets out summarized financial information for Great Lakes as at December 31, 2007 and for the period February 23, 2007 to December 31, 2007:

Summarized Consolidated Great Lakes Balance Sheet

December 31 (millions of dollars)	2007
Assets	
Cash and short-term investments	32.0
Other current assets	55.5
Plant, property and equipment, net	969.2
	1,056.7
Liabilities and Partners' Equity	
Current liabilities	50.7
Deferred credits	0.4
Long-term debt, including current maturities	440.0
Partners' capital	565.6
	1,056.7

Summarized Consolidated Great Lakes Income Statement

For the period February 23 to December 31 (millions of dollars)	2007
Transmission revenues	236.2
Operating expenses	(53.7)
Depreciation	(49.4)
Financial charges, net and other	(27.6)
Net income	105.5

NOTE 4 INVESTMENT IN NORTHERN BORDER

The Partnership owns a 50 per cent general partner interest in Northern Border. The remaining 50 per cent partnership interest in Northern Border is held by ONEOK Partners, L.P. (ONEOK), a publicly traded limited partnership. The Northern Border system was operated by ONEOK Partners GP, LLC (ONEOK Partners GP), a wholly-owned subsidiary of ONEOK, Inc. during the three months ended March 31, 2007. Effective April 1, 2007, TransCanada Northern Border Inc. (TCNB), a wholly-owned subsidiary of TransCanada, became the operator of Northern Border. Northern Border is regulated by the FERC.

TC PipeLines Intermediate Limited Partnership, as one of the general partners, may be exposed to the commitments and contingencies of Northern Border. TC PipeLines, LP holds a 98.9899 per cent limited partnership interest in TC PipeLines Intermediate Limited Partnership.

On April 6, 2006, the Partnership acquired an additional 20 per cent general partner interest in Northern Border. The Partnership uses the equity method of accounting for its investment in Northern Border. TC PipeLines' equity income for the year ended December 31, 2006 includes 30 per cent of the net income of Northern Border up to April 6, 2006 and 50 per cent thereafter. Equity income from Northern Border includes amortization of a $10 million transaction fee paid to the operator of Northern Border as an inducement to become operator at the time of the additional 20 per cent acquisition in April 2006. TC PipeLines' equity income from its investment in Northern Border amounted to $61.2 million for the year ended December 31, 2007 (2006 - $56.6 million; 2005 - $45.7 million). Northern Border had no undistributed earnings for the years ended December 31, 2007, 2006 and 2005.

The following sets out summarized financial information for Northern Border as at December 31, 2007 and 2006 and for the years ended December 31, 2007, 2006 and 2005:

Summarized Northern Border Balance Sheet

December 31 (millions of dollars)	2007	2006
Assets		
Cash and short-term investments	**22.9**	11.0
Other current assets	**39.8**	35.5
Plant, property and equipment, net	**1,428.3**	1,475.7
Other assets	**23.9**	22.5
	1,514.9	1,544.7
Liabilities and Partners' Equity		
Current liabilities	**53.4**	47.7
Deferred credits and other	**8.1**	2.1
Long-term debt, including current maturities and notes payable	**615.3**	619.8
Partners' equity		
Partners' capital	**840.5**	874.1
Accumulated other comprehensive (loss)/income	**(2.4)**	1.0
	1,514.9	1,544.7

Summarized Northern Border Income Statement

Year ended December 31 (millions of dollars)	2007	2006	2005
Transmission revenues	**309.4**	310.9	321.7
Operating expenses	**(83.5)**	(81.0)	(70.8)
Depreciation	**(60.7)**	(58.7)	(58.1)
Financial charges, net and other	**(41.1)**	(41.3)	(40.5)
Net income	**124.1**	129.9	152.3

NOTE 5 INVESTMENT IN TUSCARORA

As of December 31, 2007, the Partnership wholly-owns Tuscarora. On December 19, 2006, the Partnership acquired an additional 49 per cent general partner interest in Tuscarora from Tuscarora Gas Pipeline Co., a wholly-owned subsidiary of Sierra Pacific Resources. Prior to this acquisition, the Partnership used the equity method of accounting for its investment in Tuscarora. Subsequent to this acquisition, the Partnership used the consolidation method of accounting for its investment in Tuscarora. On December 31, 2007, the Partnership acquired the remaining two per cent general partner interest in Tuscarora, with one per cent purchased from a wholly-owned subsidiary of TransCanada and the other one per cent purchased from Tuscarora Gas Pipeline Co. Tuscarora is operated by TCNB. Tuscarora is regulated by the FERC.

The Partnership recorded net income from Tuscarora under the consolidation method of $11.4 million and $0.4 million for the year ended December 31, 2007 and the period December 20, 2006 to December 31, 2006, respectively. TC PipeLines' equity income from its investment in Tuscarora amounted to $5.9 million and $7.5 million for the period January 1, 2006 to December 19, 2006 and the year ended December 31, 2005, respectively. Tuscarora had no undistributed earnings for the years ended December 31, 2007, 2006 and 2005. For the year ended December 31, 2007, the following customers contributed to more than 10 per cent of Tuscarora's revenue: Sierra Pacific Power Company (72 per cent), Southwest Gas Company (13 per cent) and Barrick Goldstrike Mines (11 per cent).

The following sets out summarized financial information for Tuscarora as at December 31, 2007 and 2006 and for the years ended December 31, 2007, 2006 and 2005:

Summarized Tuscarora Balance Sheet

December 31 (millions of dollars)	2007	2006
Assets		
Cash and short-term investments	**5.5**	2.2
Other current assets	**2.6**	2.5
Plant, property and equipment, net	**134.1**	127.0
Other assets	**1.2**	1.2
	143.4	132.9
Liabilities and Partners' Equity		
Current liabilities	**6.1**	2.4
Long-term debt, including current maturities	**66.4**	71.1
Partners' equity		
Partners' capital	**70.9**	59.3
Accumulated other comprehensive income	—	0.1
	143.4	132.9

Summarized Tuscarora Income Statement

Year ended December 31 (millions of dollars)	2007	2006	2005
Transmission revenues	**27.2**	29.5	32.3
Operating expenses	**(4.9)**	(4.7)	(4.4)
Depreciation	**(6.3)**	(6.2)	(6.2)
Financial charges, net and other	**(4.4)**	(5.3)	(5.6)
Net income	**11.6**	13.3	16.1

Summarized Tuscarora Cash Flow Statement

Year ended December 31 (millions of dollars)	2007	2006	2005
Cash flows provided by operating activities	**19.9**	20.5	22.3
Cash flows used in investing activities	**(13.2)**	(1.5)	(0.9)
Cash flows used in financing activities	**(3.4)**	(20.6)	(21.2)
Increase/(decrease) in cash and short-term investments	**3.3**	(1.6)	0.2
Cash and short-term investments, beginning of year	**2.2**	3.8	3.6
Cash and short-term investments, end of year	**5.5**	2.2	3.8

NOTE 6 PLANT, PROPERTY AND EQUIPMENT

	2007			2006		
December 31 (millions of dollars)	Cost	Accumulated Depreciation	Net Book Value	Cost	Accumulated Depreciation	Net Book Value
Tuscarora						
Pipeline	**146.6**	**53.1**	**93.5**	146.1	48.2	97.9
Compression	**25.0**	**5.5**	**19.5**	25.0	4.5	20.5
Metering and other	**11.0**	**3.1**	**7.9**	10.0	2.7	7.3
Under construction	**13.2**	**—**	**13.2**	1.3	—	1.3
	195.8	**61.7**	**134.1**	182.4	55.4	127.0

NOTE 7 ACQUISITIONS

Great Lakes

On February 22, 2007, the Partnership acquired a 46.45 per cent general partner interest in Great Lakes from El Paso Corporation (El Paso). The total purchase price was $942.4 million, subject to certain closing adjustments, and included the indirect assumption of $209.0 million of debt. The acquisition was partially financed through a private placement of common units for gross proceeds of $600.0 million which closed concurrently with the acquisition. In addition, TC PipeLines GP maintained its two per cent general partner interest in the Partnership by contributing $12.6 million to the Partnership in connection with the private placement. The Partnership funded the balance of the total consideration with a draw on its senior credit facility, which was amended and restated in connection with the acquisition.

The acquisition was accounted for using the purchase method of accounting. The purchase price was allocated using an estimate of fair value of the net assets at the date of acquisition. The difference between the purchase price and the estimated fair value of net assets of $457.5 million, being goodwill, was recorded as part of the Partnership's investment in Great Lakes.

Great Lakes' business is subject to rate regulation based on historical costs which do not change with market conditions or change of ownership. Accordingly, upon acquisition, the assets and liabilities of Great Lakes were determined to have a fair value equal to the rate regulated historical costs. No intangibles other than goodwill were identified in the acquisition.

TransCanada, which previously held a 50 per cent interest in Great Lakes, acquired the other 3.55 per cent general partner interest simultaneously with the Partnership's acquisition of its interest. In connection with these transactions, a wholly-owned subsidiary of TransCanada became the operator of Great Lakes.

Northern Border

On April 6, 2006, the Partnership acquired an additional 20 per cent general partner interest in Northern Border for $298.0 million plus a $10.0 million transaction fee payable to TCNB, bringing the Partnership's total interest to 50 per cent. Through the acquisition, TC PipeLines indirectly assumed $121.7 million of debt. The Partnership funded the transaction through a Bridge Loan Credit Facility (see note 8). In connection with this transaction, TCNB became the operator of Northern Border in April 2007.

The acquisition was accounted for using the purchase method of accounting. The purchase price was allocated using an estimate of fair value of the net assets at the date of acquisition. The difference between the purchase price and the fair value of net assets of $115.0 million, being goodwill, was recorded as part of the Partnership's investment in Northern Border. The $10.0 million transaction fee payable to the operator has been recorded as part of the Partnership's investment in Northern Border and is being amortized over the term of the related operating agreement.

Northern Border's business is subject to rate regulation based on historical costs which do not change with market conditions or change of ownership. Accordingly, upon acquisition, the assets and liabilities of Northern Border were determined to have a fair value equal to the rate regulated historical costs. No intangibles other than goodwill were identified in the acquisition.

Tuscarora

On December 19, 2006, the Partnership acquired an additional 49 per cent general partnership interest in Tuscarora for $99.8 million. Through the acquisition TC PipeLines indirectly assumed $37.5 million of Tuscarora debt. The Partnership funded the transaction through the Senior Credit Facility (see note 8). In connection with this transaction, TCNB became the operator of Tuscarora.

The acquisition was accounted for using the purchase method of accounting. The purchase price was allocated as follows using an estimate of fair value of the assets acquired and liabilities assumed at the date of acquisition:

Purchase Price Allocation (millions of dollars)	Acquisition of additional 49% interest
Current assets	4.7
Plant, property and equipment	56.6
Other non-current assets	0.7
Goodwill	79.1
Current liabilities	(2.6)
Long-term debt	(37.5)
Non-controlling interests	(1.2)
	99.8

On December 31, 2007, the Partnership acquired the other two per cent general partner interest in Tuscarora. One per cent was purchased from a wholly-owned subsidiary of TransCanada, while the other one per cent was purchased from Tuscarora Gas Pipeline Co. for a total purchase price of $3.9 million. The acquisitions were accounted for using the purchase method of accounting. The difference between the combined purchase prices and the non-controlling interest recorded on the Partnership's balance sheet of $2.6 million was recorded as goodwill.

Tuscarora's business is subject to rate regulation based on historical costs which do not change with market conditions or change of ownership. Accordingly, upon acquisition, the assets and liabilities of Tuscarora were determined to have a fair value equal to the rate regulated historical costs. No intangibles other than goodwill were identified in the acquisitions.

Pro forma financial information for the Great Lakes, Northern Border and Tuscarora acquisitions

The following unaudited Partnership pro forma financial information for the years ended December 31, 2007 and 2006 has been prepared as if the significant acquisitions mentioned above occurred on January 1, 2006:

Year ended December 31 (millions of dollars except per unit amounts)	2007	2006
Equity income from investment in Great Lakes	**59.6**	56.8
Equity income from investment in Northern Border	**61.2**	64.1
Transmission revenues	**27.2**	29.5
Net income	**98.3**	99.9
Net income per common unit	**$ 2.58**	$ 2.70

NOTE 8 CREDIT FACILITIES AND LONG-TERM DEBT

(millions of dollars)	2007	2006
Senior Credit Facility	**507.0**	397.0
Series A Senior Notes	**54.5**	57.9
Series B Senior Notes	**5.5**	6.0
Series C Senior Notes	**6.4**	7.2
	573.4	468.1

On February 28, 2006, the Partnership renewed a $20.0 million unsecured credit facility (Revolving Credit Facility). In 2006, TC PipeLines repaid the Revolving Credit Facility in full and it was terminated. The interest rate on the Revolving Credit Facility averaged 5.60 per cent for the year ended December 31, 2006.

On March 31, 2006, the Partnership entered into an unsecured credit agreement for a $310.0 million credit facility (Bridge Loan Credit Facility) with a banking syndicate. Borrowings under the Bridge Loan Credit Facility bore interest, at the option of the Partnership, at the LIBOR or the base rate plus an applicable margin. On April 5, 2006, the Partnership borrowed $307.0 million under the Bridge Loan Credit Facility to finance the purchase price and a $10.0 million transaction fee payable in connection with the acquisition of an additional 20 per cent general partner interest in Northern Border. The remaining $3.0 million commitment under the Bridge Loan Credit Facility was terminated. On December 12, 2006, the Bridge Loan Credit Facility was refinanced through a $297.0 million draw on a $410.0 million credit agreement (Senior Credit Facility) with a banking syndicate and the use of $10.0 million cash on hand. The interest rate on the Bridge Loan Credit Facility averaged 6.29 per cent for the year ended December 31, 2006.

On December 12, 2006, the Partnership entered into a credit agreement for the Senior Credit Facility. On December 19, 2006, TC PipeLines borrowed an additional $100.0 million under the Senior Credit Facility to finance the purchase price of an additional 49 per cent general partner interest in Tuscarora.

On February 13, 2007, the Senior Credit Facility was amended and restated in connection with the Great Lakes acquisition. The amount available under the Senior Credit Facility increased from $410.0 million to $950.0 million, consisting of a $700.0 million senior term loan and a $250.0 million senior revolving credit facility, with $194.0 million of the senior term loan available being terminated upon closing of the Great Lakes acquisition. In accordance with the Senior Credit Facility agreement, once repaid, a senior term loan cannot be re-borrowed. On November 29, 2007, $18.0 million of the senior term loan was repaid and hence terminated, leaving $488.0 million available and outstanding under the senior term loan. At December 31, 2007, $19.0 million is outstanding under the senior revolving credit facility, leaving $231.0 million available for future borrowings.

The Senior Credit Facility matures on December 12, 2011, at which time all amounts outstanding will be due and payable. Amounts borrowed may be repaid in part or in full prior to that time without penalty. Borrowings under the Senior Credit Facility will bear interest based, at the Partnership’s election, on the LIBOR or the prime rate plus, in either case, an applicable margin. There was $507.0 million outstanding under the Senior Credit Facility at December 31, 2007 (2006 - $397.0 million). The interest rate on the Senior Credit Facility averaged 6.01 per cent for the year ended December 31, 2007 (2006 – 6.16 per cent). After hedging activity, the interest rate incurred on the Senior Credit Facility averaged 5.75 per cent for the year ended December 31, 2007. Prior to hedging activities, the interest rate was 5.62 per cent at December 31, 2007 (2006 – 6.07 per cent). At December 31, 2007, the Partnership was in compliance with its financial covenants.

In 1995, Tuscarora issued $91.7 million of 7.13 per cent senior secured notes, which mature on December 21, 2010 (Series A). In 2000, Tuscarora issued $8.0 million of 7.99 per cent senior secured notes, which mature on December 21, 2010 (Series B). In 2002, Tuscarora issued $10.0 million of 6.89 per cent senior secured notes, which mature on December 21, 2012 (Series C). The Series A, Series B and Series C notes (collectively, the Notes) have a final payment at maturity of $46.7 million, $4.1 million and $2.7 million, respectively. The Notes are secured by Tuscarora’s transportation contracts, supporting agreements and substantially all of Tuscarora’s property. The credit agreement for the Notes contains certain provisions that include, among other items, limitations on additional indebtedness and distributions to partners.

Annual maturities of the Senior Credit Facility and the Notes are summarized as follows:

(millions of dollars)	
2008	4.6
2009	4.4
2010	53.5
2011	507.8
2012	3.1
	573.4

NOTE 9 PARTNERS’ EQUITY

On February 22, 2007, the Partnership completed a private placement of 17,356,086 common units at $34.57 per common unit for gross proceeds of $600.0 million which closed concurrently with the Great Lakes acquisition. TransCan Northern Ltd. (TransCan Northern), a wholly-owned subsidiary of TransCanada, purchased 8,678,045 of

the 17,356,086 common units issued for gross proceeds of $300.0 million. In addition, TC PipeLines GP maintained its two per cent general partner interest in the Partnership by contributing $12.6 million to the Partnership in connection with the private placement.

At December 31, 2007, Partners’ equity consists of 34,856,086 common units representing an aggregate 98 per cent limited partner interest in the Partnership (including 2,035,106 common units held by the general partner and 8,678,045 common units held by TransCan Northern) and an aggregate two per cent general partner interest. In aggregate, the general partner’s interests represent an effective 7.7 per cent ownership in the Partnership at December 31, 2007 (December 31, 2006 — 13.4 per cent).

NOTE 10 FINANCIAL CHARGES, NET AND OTHER

Year ended December 31 (millions of dollars)	2007	2006	2005
Interest expense on long-term debt	**34.9**	14.8	—
Interest expense on short-term debt	**0.3**	0.3	1.1
Interest income	**(0.9)**	(0.4)	(0.1)
Amortization of other assets	**0.4**	0.9	—
Other	**(0.9)**	0.2	—
	33.8	15.8	1.0

NOTE 11 NET INCOME PER COMMON UNIT

Net income per common unit is computed by dividing net income, after deduction of the general partner's allocation, by the weighted average number of common units outstanding. The general partner's allocation is equal to an amount based upon the general partner's two per cent interest, adjusted to reflect an amount equal to incentive distributions. Incentive distributions are received by the general partner if quarterly cash distributions on the common units exceed levels specified in the partnership agreement. Net income per common unit was determined as follows:

Year ended December 31 (millions of dollars except per unit amounts)	2007	2006	2005
Net income	**89.0**	44.7	50.2
Net income allocated to general partner			
General partner interest	**(1.8)**	(0.9)	(1.0)
Incentive distribution income allocation	**(5.9)**	(2.0)	(1.9)
	(7.7)	(2.9)	(2.9
Net income allocable to common units	**81.3**	41.8	47.3
Weighted average common units outstanding *(millions)*	**32.3**	17.5	17.5
Net income per common unit	**$ 2.51**	$ 2.39	$ 2.70

NOTE 12 CASH DISTRIBUTIONS

The Partnership makes cash distributions to its partners with respect to each calendar quarter within 45 days after the end of each quarter. Distributions are based on available cash, which includes all cash and cash equivalents of the Partnership and working capital borrowings less reserves established by the general partner. The Unitholders currently receive a quarterly distribution of $0.665 per unit if and to the extent there is sufficient available cash.

As an incentive, the general partner's percentage interest in quarterly distributions is increased after certain specified target levels are met. The incremental incentive distributions payable to the General Partner are 15 per cent, 25 per cent, and 50 per cent of all quarterly distributions of Available Cash that exceed target levels of $0.45, $0.5275 and $0.69, respectively, per unit. For the year ended December 31, 2007, the Partnership distributed $2.565 per unit (2006 - $2.325 per unit; 2005 - $2.30 per unit). The distributions for the year ended December 31, 2007 included

incentive distributions to the general partner in the amount of $5.9 million (2006 - $2.0 million; 2005 - $1.9 million). Partnership income is allocated to the general partner and the limited partners in accordance with their respective partnership percentages, after giving effect to any priority income allocations for incentive distributions that are allocated 100 per cent to the general partner.

NOTE 13 RELATED PARTY TRANSACTIONS

The Partnership does not have any employees. The management and operating functions are provided by the general partner. The general partner does not receive a management fee or other compensation in connection with its management of the Partnership. The Partnership reimburses the general partner for all costs of services provided, including the costs of employee, officer and director compensation and benefits, and all other expenses necessary or appropriate to the conduct of the business of, and allocable to, the Partnership. Such costs include (i) overhead costs (such as office space and equipment) and (ii) out-of-pocket expenses related to the provision of such services. The Partnership Agreement provides that the general partner will determine the costs that are allocable to the Partnership in any reasonable manner determined by the general partner in its sole discretion. Total costs charged to the Partnership by the general partner were $1.9 million for the year ended December 31, 2007 (2006 - $1.2 million; 2005 - $1.1 million).

A wholly-owned subsidiary of TransCanada became the operator of Great Lakes through TransCanada's acquisition of Great Lakes Gas Transmission Company on February 22, 2007. On December 19, 2006, the Partnership acquired an additional 49 per cent general partner interest in Tuscarora. In connection with this transaction, TCNB became the operator of Tuscarora. TransCanada and its affiliates provide capital and operating services to our pipeline systems. TransCanada and its affiliates incur costs on behalf of our pipeline systems, including, but not limited to, employee benefit costs, property and liability insurance costs, and transition costs. Total costs charged to our pipeline systems in 2007 by TransCanada and its affiliates and amounts owed to TransCanada and its affiliates at December 31, 2007 are summarized in the following table:

(millions of dollars)	Great Lakes	Northern Border	Tuscarora
Costs charged by TransCanada and its affiliates	25.6	22.5	1.8
Impact on the Partnership's net income	11.2	11.0	0.9
Amount owed to TransCanada and its affiliates	1.9	3.0	3.5

Great Lakes earns transportation revenues from TransCanada and its affiliates under fixed priced contracts with remaining terms ranging from one to ten years. Great Lakes earned $113.9 million of transportation revenues under these contracts for the period February 23, 2007 to December 31, 2007. This amount represents 48.2 per cent of total revenues earned by Great Lakes for the period February 23, 2007 to December 31, 2007. $52.9 million of transportation revenue is included in the Partnership's equity income from Great Lakes during the same period. At December 31, 2007, $10.0 million is included in Great Lakes' receivables in regards to the transportation contracts with TransCanada and its affiliates.

For the year ended December 31, 2007, the Partnership recorded transmission revenues of $19.4 million in regards to various contracts with Sierra

Pacific Power Company, a wholly-owned subsidiary of Sierra Pacific Resources.

On April 6, 2006, the Partnership acquired an additional 20 per cent general partner interest in Northern Border. At the time of this transaction, the Partnership paid a $10.0 million transaction fee to TransCanada Northern Border related to the assumption of operatorship. This fee has been recorded as part of the Partnership's investment in Northern Border and is being amortized over the term of the related operating agreement partially offsetting equity income.

On May 8, 2007, the Partnership reimbursed TransCanada $2.8 million for third party costs related to the Partnership's acquisition of its interest in Great Lakes. On September 26, 2007, the Partnership reimbursed

TransCanada $1.2 million for a working capital adjustment related to the Partnership's acquisition of its interest in Great Lakes.

On December 31, 2007, the Partnership acquired a one per cent general partner interest in Tuscarora from a wholly-owned subsidiary of TransCanada for $2.0 million. The purchase price of this acquisition was derived from the formula used to calculate the purchase price of a separate one per cent general partner interest in Tuscarora which was purchased from Tuscarora Gas Pipeline Co. on the same day.

NOTE 14 QUARTERLY FINANCIAL DATA (unaudited)

The following sets forth selected financial data for the four quarters of each of 2007 and 2006.

Quarter ended (millions of dollars except per unit amounts)	Mar 31	Jun 30	Sep 30	Dec 31
2007				
Equity income	**24.8**	**23.4**	**30.4**	**31.6**
Transmission revenues	**6.9**	**6.7**	**6.7**	**6.9**
Net income	**20.0**	**17.7**	**24.6**	**26.7**
Net income per common unit	**$ 0.73**	**$ 0.45**	**$ 0.64**	**$ 0.70**
Cash distributions paid	**11.3**	**24.9**	**25.1**	**25.4**
2006				
Equity income	13.2	13.9	17.9	17.5
Transmission revenues	—	—	—	0.9
Net income	12.4	9.0	12.0	11.3
Net income per common unit	$ 0.67	$ 0.47	$ 0.65	$ 0.60
Cash distributions paid	10.7	10.8	10.7	11.3

NOTE 15 CAPITAL REQUIREMENTS

On April 30, 2007, the Partnership made a contribution of $7.5 million to Northern Border, representing the Partnership's 50 per cent share of a $15.0 million cash call issued by Northern Border. The funds were used by Northern Border to repay indebtedness.

Tuscarora incurred $13.2 million of capital expenditures during 2007, of which $12.2 million related to its compressor station expansion in Likely, California. These capital expenditures were funded with operating cash flows.

The Partnership contributed $3.1 million to Northern Border during 2006, representing its then 30 per cent share of a $10.3 million cash call issued by Northern Border. The funds were used by Northern Border to fund an expansion project.

NOTE 16 DERIVATIVE FINANCIAL INSTRUMENTS

The carrying value of cash and short-term investments, accounts receivable and other, accounts payable and accrued interest approximate their fair values because of the short maturity or duration of these instruments, or because the instruments carry a variable rate of interest or a rate that approximates current rates. The fair value of the Partnership's long-term debt is estimated by discounting the future cash flows of each instrument at current borrowing rates.

The estimated fair values of the Partnership's and its subsidiary's long-term debt as of December 31, 2007 and 2006 are as follows:

	2007		2006	
(millions of dollars)	Carrying Value	Fair Value	Carrying Value	Fair Value
Senior Credit Facility	**507.0**	**507.0**	397.0	397.0
Series A Senior Notes	**54.5**	**58.7**	57.9	60.9
Series B Senior Notes	**5.5**	**6.0**	6.0	6.4
Series C Senior Notes	**6.4**	**7.0**	7.2	7.5

	573.4	**578.7**	468.1	471.8

The Partnership's short-term and long-term debt results in exposures to changing interest rates. The Partnership uses derivatives to assist in managing its exposure to interest rate risk.

At December 31, 2007, the fair value of the interest rate swaps and options accounted for as hedges was negative $9.8 million (2006 - positive $1.6 million). The fair value of interest rate swaps and options have been calculated using year-end market rates. The notional amount hedged was $475.0 million as at December 31, 2007 (2006 - $200.0 million). $300.0 million of variable-rate debt is hedged by an interest rate swap during the period from March 12, 2007 through December 12, 2011, where the weighted average fixed interest rate paid is 4.89 per cent. $100.0 million of variable-rate debt is hedged by an interest rate option during the period from May 22, 2007 through May 22, 2009 to an interest rate range between a weighted average floor of 4.09 per cent and a cap of 5.35 per cent. $75.0 million of variable-rate debt is hedged by an interest rate swap during the period from February 29, 2008 through February 28, 2011, where the fixed interest rate paid will be 3.86 per cent. In addition to these fixed rates, the Partnership pays an applicable margin in accordance with the Senior Credit Facility agreement. The interest rate swaps and options are structured such that the cash flows match those of the Senior Credit Facility.

NOTE 17 ACCOUNTING PRONOUNCEMENTS

In 2006, the Financial Accounting Standards Board issued SFAS No. 157, *Fair Value Measurements,* and during 2007,issued SFAS No. 141(R), *Business Combinations - revised*, SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities – including an amendment of FASB Statement No. 115*, and SFAS No. 160, *Noncontrolling Interests in Consolidated financial Statements*.

SFAS No. 157 establishes a framework for measuring fair value and requires additional disclosures about fair value measurements. The effect of adopting SFAS No. 157 is not expected to be material to our results of operations or financial position.

SFAS No. 141(R) replaces SFAS No. 141, *Business Combinations*. SFAS No. 141 (R) retains the fundamental requirements of SFAS No. 141 that the acquisition method of accounting be used for all business combinations and for an acquirer to be identified for each business combination, with the objective of improving the relevance and comparability of the information that a reporting entity provides in its financial reports about a business combination and its effects. The requirements of this standard will not have a material impact on the results of the Partnership.

SFAS No. 159 permits entities to choose to measure selected financial assets and financial liabilities at fair value. The fair value option established by SFAS No. 159 permits all entities to choose to measure eligible items at fair value at specified election dates. The effect of adopting SFAS No. 159 is not expected to be material to our results of operations or financial position.

SFAS No. 160 clarifies the classification of noncontrolling interests in consolidated statements of financial position and the accounting for and reporting of transactions between the reporting entity and holders of such noncontrolling interests. The Partnership does not have noncontrolling interests and therefore, is not affected by the changes resulting from this standard.

In June 2007 the Emerging Issues Task Force of the FASB issued EITF 07-4, "Application of the Two-Class Method under FASB Statement No. 128, *Earnings per Share,* to Master Limited Partnerships". EITF 07-4 addresses how current period earnings of a Master Limited Partnership (MLP) should be allocated to the general partner, limited partners and when applicable, incentive distribution rights when applying the two-class method under Statement 128. A tentative conclusion was ratified by the FASB in December 2007. We are currently reviewing the applicability of EIFT 07-4 to our results of operations and financial position.

NOTE 18 SUBSEQUENT EVENTS

On January 17, 2008, the Board of Directors of the general partner declared the Partnership's 2007 fourth quarter cash distribution. The fourth quarter cash distribution which was paid on February 14, 2008 to unitholders of record as of January 31, 2008, totaled $25.6 million and was paid in the following manner: $23.2 million to common unitholders (including $1.4 million to the general partner as holder of 2,035,106 common units and $5.8 million to TransCan Northern as holder of 8,678,045 common units), $1.9 million to the general partner as holder of the incentive distribution rights, and $0.5 million to the general partner in respect of its two per cent general partner interest.

Great Lakes declared and paid a distribution of $25.0 million on February 1, 2008, of which the Partnership received its 46.45 per cent share or $11.6 million.

Northern Border declared and paid a distribution of $46.3 million on February 1, 2008, of which the Partnership received its 50 per cent share or $23.2 million.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Partners and Management Committee
Great Lakes Gas Transmission Limited Partnership:

We have audited the accompanying consolidated balance sheets of Great Lakes Gas Transmission Limited Partnership and subsidiary (partnership) as of December 31, 2007 and 2006, and the related consolidated statements of income and partners' capital, and cash flows for each of the years in the three-year period ended December 31, 2007. These consolidated financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Partnership's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Great Lakes Gas Transmission Limited Partnership and subsidiary as of December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2007 in conformity with U.S. generally accepted accounting principles.

The Partnership's consolidated financial statements for 2006 and 2005 were previously prepared as though the Partnership was a corporation and current income taxes and amounts equivalent to deferred income taxes were recorded in those financial statements. As more fully described in note 2 to the consolidated financial statements, the Partnership adopted a policy to exclude income taxes from the consolidated financial statements at the beginning of the current year. Consequently, the Partnership's consolidated financial statements for 2006 and 2005 have been restated to exclude income taxes.

/s/ KPMG LLP

Detroit, Michigan
January 22, 2008

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP
CONSOLIDATED STATEMENTS OF INCOME AND PARTNERS' CAPITAL

Years ended December 31 (Thousands of dollars)	2007	2006 As Adjusted	2005 As Adjusted
Transportation Revenues			
Affiliated Revenues	$ **137,166**	161,605	173,796
Nonaffiliated Revenues	**145,660**	110,652	106,947
	282,826	272,257	280,743
Operating Expenses			
Operation and Maintenance	**42,125**	34,083	41,312
Depreciation	**58,046**	57,612	57,693
Property and Other Non Income Taxes	**22,195**	25,965	26,756
	122,366	117,660	125,761
Operating Income	**160,460**	154,597	154,982
Other Income (Expense)			
Interest on Long Term Debt	**(35,096)**	(35,970)	(36,844)
Other, Net	**2,937**	3,704	1,897
	(32,159)	(32,266)	(34,947)
Net Income	$ **128,301**	122,331	120,035
Partners' Capital			
Balance at Beginning of Year	$ **630,849**	640,617	674,409
Contributions by General Partners	—	—	30,976
Net Income	**128,301**	122,331	120,035
Distributions to Partners	**(193,500)**	(132,099)	(184,803)
Balance at End of Year	$ **565,650**	630,849	640,617

The accompanying notes are an integral part of these financial statements.

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP
CONSOLIDATED BALANCE SHEETS

As of December 31 (Thousands of dollars)	2007	2006 As Adjusted
ASSETS		
Current Assets		
Cash and Cash Equivalents	**$ 31,960**	78,641
Accounts Receivable *(Net of allowance of $800 in 2007 and $1,000 in 2006)*	**29,229**	16,327
Receivable from Affiliates	**11,607**	18,954
Materials and Supplies	**11,257**	10,908
Prepayments	**3,424**	4,286
	87,477	129,116
Gas Utility Plant		
Property, Plant and Equipment	**2,045,133**	2,038,123
Less Accumulated Depreciation	**1,075,873**	1,030,059
	969,260	1,008,064
	$ 1,056,737	1,137,180
LIABILITIES AND PARTNERS' CAPITAL		
Current Liabilities		
Current Maturities of Long Term Debt	**$ 10,000**	10,000
Accounts Payable	**26,468**	16,579
Payable to Affiliates	**1,871**	2,362
Property Taxes	**9,300**	17,793
Other Non Income Taxes	**3,645**	3,939
Accrued Interest	**9,143**	9,289
Other	**264**	4,136
	60,691	64,098
Long Term Debt	**430,000**	440,000
Other Liabilities	**396**	2,233
Partners' Capital	**565,650**	630,849
	$ 1,056,737	1,137,180

The accompanying notes are an integral part of these financial statements.

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP
CONSOLIDATED STATEMENTS OF CASH FLOWS

Years ended December 31 (Thousands of dollars)	2007	2006 As Adjusted	2005 As Adjusted
Cash Flow Increase (Decrease) from:			
Operating Activities			
Net Income	**$ 128,301**	122,331	120,035
Adjustments to Reconcile Net Income to Operating Cash Flows:			
Depreciation	**58,046**	57,612	57,693
Allowance for Funds Used During Construction	**(438)**	(386)	(135)
Changes in Current Assets and Liabilities:			
Accounts Receivable	**(12,902)**	17,477	(2,516)
Receivable from Affiliates	**7,347**	(2,233)	(3,872)
Accounts Payable	**9,889**	(15,048)	6,631
Payable to Affiliates	**(491)**	(2,393)	1,767
Property and Other Non Income Taxes	**(8,787)**	(2,716)	341
Other	**(5,342)**	(3,309)	1,187
	175,623	171,335	181,131
Investing Activities			
Investment in Utility Plant	**(18,804)**	(18,953)	(16,102)
Insurance Proceeds	—	8,122	—
	(18,804)	(10,831)	(16,102)
Financing Activities			
Repayment of Long Term Debt	**(10,000)**	(10,000)	(10,000)
Contributions by General Partners	—	—	30,976
Distribution to Partners	**(193,500)**	(132,099)	(184,803)
	(203,500)	(142,099)	(163,827)
Change in Cash and Cash Equivalents	**(46,681)**	18,405	1,202
Cash and Cash Equivalents:			
Beginning of Year	**78,641**	60,236	59,034

End of Year	**$ 31,960**	78,641	60,236
Supplemental Disclosure of Cash Flow Information			
Cash Paid During the Year for Interest (Net of Amounts Capitalized of $184, $153 and $47, Respectively)	**$ 35,294**	36,132	37,018

The accompanying notes are an integral part of these financial statements.

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND MANAGEMENT

Great Lakes Gas Transmission Limited Partnership (Partnership) is a Delaware limited partnership that owns and operates an interstate natural gas pipeline system. The Partnership transports natural gas for delivery to wholesale customers in the Midwestern and northeastern United States and eastern Canada. The partners, their parent companies, and partnership ownership percentages at December 31 are as follows:

Partner (Parent Company)	Ownership % 2007	2006
General Partners:		
El Paso Great Lakes Company, LLC (El Paso Corporation)	—	46.45
TransCanada GL, Inc. (TransCanada Pipelines Limited)	**46.45**	46.45
TC GL Intermediate Limited Partnership (TC PipeLines, LP)	**46.45**	—
Limited Partner:		
Great Lakes Gas Transmission Company (TransCanada Pipelines Limited - 2007 and El Paso Corporation and TransCanada Pipelines Limited - 2006)	**7.10**	7.10

On February 22, 2007 (acquisition date), TC PipeLines, LP (TCPL) and TransCanada Corporation (TransCanada) acquired El Paso Corporation's (El Paso) 46.45% ownership interest in the Partnership and 50% interest in Great Lakes Gas Transmission Company (Company), respectively.

The day-to-day operation of the Partnership activities is the responsibility of the Company pursuant to the Partnership's Operating Agreement with the Company. As of the acquisition date, the Company uses TransCanada and its affiliates to provide operating services. The Partnership is charged for the salaries, benefits and expenses of TransCanada and its affiliates for services attributable to its operations.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation and Basis of Presentation

The consolidated financial statements include the accounts of the Partnership and GLGT Aviation Company, a wholly owned subsidiary. GLGT Aviation Company owns a fractional interest in a transport aircraft used principally for pipeline operations. Intercompany amounts have been eliminated.

For purposes of reporting cash flows, the Partnership considers all liquid investments with original maturities of three months or less to be cash equivalents. Under the Partnership's cash management system, the bank notifies the Partnership daily of checks presented for payment against its disbursement account. The Company transfers funds from short-term investments to cover the checks presented for payment. This system results in a book cash overdraft in the disbursement account as a result of checks outstanding. The book overdraft, which was reclassified to accounts payable, was $5.8 million and $0.3 million at December 31, 2007 and 2006, respectively.

The fair value of long term debt is discussed in footnote 4. All other financial instruments approximate fair value due to the short maturity of these instruments.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires the use of estimates and assumptions that affect the amounts reported as assets, liabilities, revenues and expenses and the disclosures in these financial statements. Although management believes these estimates are reasonable, actual results could differ from those estimates.

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES, CONTINUED

Regulation

The Partnership is subject to the rules, regulations and accounting procedures of the Federal Energy Regulatory Commission (FERC). The Partnership's accounting policies follow regulatory accounting principles prescribed under Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation*. There are no regulatory assets or liabilities reflected in these consolidated financial statements.

Revenue and Accounts Receivable

The Partnership generates transportation revenues based on transportation service contracts under a tariff regulated by the FERC. The tariff specifies maximum transportation rates and the contracts' general terms and conditions of service. The majority of the service contracts are for firm service in which the customers pay a reservation fee for capacity on the pipeline system regardless of whether they actually utilize their reserved capacity. The Partnership recognizes reservation revenues on firm contracted capacity ratably over the contract period regardless of the amount of natural gas that is transported. In addition to the reservation fee, a utilization fee is charged and the related revenue is recognized based on the volume of natural gas transported.

Accounts receivable are reported at the invoiced amount. The Partnership establishes an allowance for losses on accounts receivable if it is determined that all or a portion of the outstanding balance will not be collected. The Partnership also considers historical industry data and customer credit trends. Account balances are charged against the allowance after all means of collection have been exhausted and the potential for recovery is considered remote.

Natural Gas Imbalances

Natural gas imbalances occur when the actual amount of natural gas delivered or received differs from the scheduled amount of natural gas delivered or received. The Partnership values these imbalances due to or from customers and interconnecting pipelines at fair value. Imbalances are made up in kind, in accordance with the terms of the tariff.

Imbalances due from others are reported on the consolidated balance sheet as either accounts receivable or receivable from affiliates. Imbalances owed to others are reported on the consolidated balance sheet as either accounts payable or payable to affiliates. Imbalances are expected to settle within a year.

Materials and Supplies

Materials and supplies are valued at the lower of cost or market value with cost determined using the average cost method.

Gas Utility Plant and Depreciation

Gas utility plant is stated at cost and includes certain administrative and general expenses, plus an allowance for funds used during construction. The Partnership capitalizes major units of property replacements or improvements and expenses minor items. Planned major maintenance is accrued when, and only when, an obligating event occurs, and is recorded using the direct expensing method or the deferral method. The cost of plant retired is charged to accumulated depreciation net of salvage and cost of removal. Depreciation of gas utility plant is computed using the composite (group) method. Under this method, assets with similar lives and characteristics are grouped and depreciated as one asset. The Partnership's principal operating assets, which comprise approximately 98% of total property, plant and

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2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES, CONTINUED

equipment, are depreciated at an annual rate of 2.75%. The remaining assets are depreciated at an annual rate ranging from 4% to 20%.

The allowance for funds used during construction represents the debt and equity costs of capital funds applicable to utility plant under construction, calculated in accordance with a uniform formula prescribed by the FERC. The rates used were 10.25%, 10.37%, and 10.50% for years 2007, 2006, and 2005, respectively.

Asset Retirement Obligations

In the fourth quarter of 2005, the Partnership adopted Financial Accounting Standards Board Interpretation (FIN) No. 47, *Accounting for Conditional Asset Retirement Obligations.* FIN No. 47 requires companies to record a liability for those asset retirement obligations in which the timing and/or amount of settlement of the obligations are uncertain. These conditional obligations were not addressed by SFAS No. 143, *Accounting for Asset Retirement Obligations,* which the Partnership adopted on January 1, 2003. FIN No. 47 requires accrual of a liability when a range of scenarios indicates that the potential timing and/or settlement amounts of conditional asset retirement obligations can be determined. The Partnership has asset retirement obligations if it were to permanently retire all or part of the pipeline system; however, the amount of asset retirement obligations cannot be reasonably estimated due to the inability to determine the scope and timing of asset retirements.

Impairment of Long-Lived Assets

The Partnership assesses its long-lived assets for impairment based on SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*. A long-lived asset is tested for impairment whenever events or changes in circumstances indicate that its carrying amount may exceed the undiscounted cash flows expected to be generated by the asset. If the carrying amount exceeds the undiscounted cash flows, an impairment is recognized to the extent the carrying amount exceeds its fair value.

Accounting for Pipeline Integrity Costs

Prior to January 1, 2006, the Partnership capitalized certain costs incurred related to its pipeline integrity assessment programs as part of property, plant and equipment.

In June 2005, the FERC issued an order on *Accounting for Pipeline Assessment Costs* which generally requires that pipeline inspections and assessments incurred after January 1, 2006 be expensed. The Partnership expensed $3.3 million and $2.4 million of pipeline integrity costs in 2007 and 2006, respectively.

Change in Accounting Principle

In previously issued financial statements, the Partnership accounted for income taxes as if it were a corporation and recorded current income taxes and amounts equivalent to deferred income taxes in those financial statements. In 2007, the Partnership has concluded that a preferable accounting method is to exclude income taxes from its consolidated financial statements, as federal and most state income taxes are the responsibility of the partners.

The change in accounting principle is reported through retrospective application in accordance with SFAS No. 154, *Accounting Changes and Error Corrections*. The change in accounting principle increased 2007, 2006 and 2005 Operating Income and Net Income by $46 million, $44 million and $43 million, respectively. Cash flows from Operating Activities/Financing Activities increased/decreased by $41 million, $39 million and $33 million in 2007, 2006 and 2005, respectively. In addition, amounts equivalent to deferred income tax liabilities were removed and Partners' Capital was increased by approximately $254

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES, CONTINUED

million as of January 1, 2005, $264 million as of December 31, 2005, $269 million as of December 31, 2006, and $139 million as of December 31, 2007.

Income Taxes

Income taxes are the responsibility of our partners and are not reflected in these consolidated financial statements. The Partnership is required, for FERC regulatory purposes, to account for income taxes as if it were a corporation. As a result, for purposes of determining Partners' capital for regulatory accounting purposes, it is reduced by the amounts equivalent to the net deferred income tax liability balances.

As a result of the sale of the partnership interest, and a corresponding Internal Revenue Code Section 754 election, the pre-acquisition amounts equivalent to net deferred income tax liability balances were reduced by 46.45%. In addition, amounts equivalent to net deferred tax liabilities for pre-acquisition retirement plans were eliminated. As a result, Partners' Capital and amounts equivalent to net deferred tax liabilities were adjusted on the acquisition date by approximately $135 million as approved by the FERC. Amounts equivalent to net deferred income tax liabilities were approximately $139 million and $269 million at December 31, 2007 and 2006, respectively, and are primarily related to accelerated depreciation on utility plant.

In the third quarter of 2007, the state of Michigan enacted the Michigan Business Tax (MBT), which replaces the Michigan Single Business Tax effective January 1, 2008. The MBT is an income tax levied at the partnership level. The MBT is expected to result in an annual income tax expense of approximately $4 to $5 million and to provide a property tax credit of approximately $1 million, for a net annual impact of $3 to $4 million beginning in 2008.

Fair Value Measurements

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements", which provides guidance on measuring the fair value of assets and liabilities in the financial statements. Certain provisions are effective in 2008 and others in 2009. The effect of adopting SFAS No. 157 is not expected to be material to the consolidated financial statements.

In February 2007, the FASB issued SFAS No. 159, "Fair Value Option for Financial Assets and Financial Liabilities - Including an Amendment of FASB Statement No. 115," which permits entities to choose to measure selected financial assets and financial liabilities at fair value. The fair value option established by SFAS No. 159 permits all entities to choose to measure eligible items at fair value at specified election dates. A business entity shall report unrealized gains and losses in earnings, on items for which the fair value option has been elected, at each subsequent reporting date. SFAS No. 159 is effective for our fiscal year beginning January 1, 2008. The effect of adopting SFAS No. 159 is not expected to be material to the consolidated financial statements.

Reclassifications

Certain reclassifications have been made to the consolidated financial statements for prior years to conform to the current year presentation.

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

3. AFFILIATED COMPANY TRANSACTIONS

Affiliated company amounts included in the Partnership's consolidated financial statements, not otherwise disclosed, are as follows:

Transportation Revenues (In thousands)	2007	2006	2005
TransCanada and affiliates	$ **135,629**	150,067	156,561
El Paso and affiliates	**1,537**	11,538	17,235

Affiliated transportation revenues are primarily provided under fixed priced contracts with remaining terms ranging from 1 to 10 years.

The Partnership reimbursed the Company and affiliates for salaries, benefits and other administrative and operating incurred expenses. Benefits include pension, defined contribution plans, and other post-retirement benefits. Operating expenses charged by the Company and affiliates in 2007, 2006, and 2005 were $26,836,000, $18,022,000 and $23,913,000, respectively.

The Company participated in El Paso sponsored pension and defined contribution plans until February 28, 2007. The Company also participated in a post-retirement health care plan. After the acquisition date, the Partnership is charged for benefit plan expenses and other benefits by a TransCanada affiliate through a benefit rate on labor costs.

4. DEBT

(In thousands)	2007	2006
Senior Notes, unsecured, interest due semiannually, principal due as follows:		
8.74% series, due 2008 to 2011	$ **40,000**	50,000
9.09% series, due 2012 to 2021	**100,000**	100,000
6.73% series, due 2009 to 2018	**90,000**	90,000
6.95% series, due 2019 to 2028	**110,000**	110,000
8.08% series, due 2021 to 2030	**100,000**	100,000
	440,000	450,000
Less current maturities	**10,000**	10,000
Total long term debt less current maturities	$ **430,000**	440,000

The aggregate estimated fair value of long term debt was $525,104,000 and $516,698,000 for 2007 and 2006, respectively. The fair value is determined using discounted cash flows based on the Partnership's estimated current interest rates for similar debt.

The aggregate annual required repayments of Senior Notes is $10,000,000 in 2008 and $19,000,000 for each year 2009 through 2012.

Under the most restrictive covenants in the Senior Note Agreements, approximately $237,000,000 of partners' capital is restricted as to distributions as of December 31, 2007.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Management Committee
Northern Border Pipeline Company:

We have audited the accompanying balance sheets of Northern Border Pipeline Company (the Company) as of December 31, 2007 and 2006, and the related statements of income, comprehensive income, cash flows, and changes in partners' equity for each of the years in the three-year period ended December 31, 2007. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Northern Border Pipeline Company as of December 31, 2007 and 2006, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2007 in conformity with U.S. generally accepted accounting principles.

/s/ KPMG LLP

Omaha, Nebraska
February 27, 2008

NORTHERN BORDER PIPELINE COMPANY
BALANCE SHEETS

	December 31, 2007	December 31, 2006
	(In thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 22,937	$ 10,997
Accounts receivable	31,307	30,073
Related party receivables	2,754	355
Materials and supplies, at cost	4,205	3,970
Prepaid expenses and other	1,506	1,118
Total current assets	62,709	46,513
Property, plant and equipment:		
In service natural gas transmission plant	2,485,607	2,488,765
Construction work in progress	2,876	2,522
Total property, plant and equipment	2,488,483	2,491,287
Less: Accumulated provision for depreciation and amortization	1,060,195	1,015,646
Property, plant and equipment, net	1,428,288	1,475,641
Other assets:		
Regulatory assets (Note 2)	20,638	19,144
Unamortized debt expense	2,662	3,284
Other	589	109
Total other assets	23,889	22,537
Total assets	$ 1,514,886	$ 1,544,691
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Current maturities of long-term debt (Note 6)	$ —	$ 170,000
Accounts payable	7,179	4,577
Related party payables	5,852	2,539
Accrued taxes other than income	27,625	27,571
Accrued interest	11,283	11,515
Other	1,487	1,511
Total current liabilities	53,426	217,713
Long-term debt, net of current maturities (Note 6)	615,286	449,844
Deferred credits and other liabilities		
Related party payables	2,260	—
Regulatory liabilities (Note 2)	2,393	—
Derivative financial instruments (Note 7)	1,852	—
Other	1,616	2,099
Total deferred credits and other liabilities	8,121	2,099
Commitments and contingencies (Note 8)		
Partners' equity:		
Partners' capital	840,494	874,057
Accumulated other comprehensive income (loss)	(2,441)	978
Total partners' equity	838,053	875,035
Total liabilities and partners' equity	$ 1,514,886	$ 1,544,691

The accompanying notes are an integral part of these financial statements.

NORTHERN BORDER PIPELINE COMPANY
STATEMENTS OF INCOME

	Years Ended December 31, 2007	2006	2005
	(In thousands)		
Operating revenue	$ 309,376	$ 310,900	$ 321,651
Operating expenses			
Operations and maintenance	54,057	49,500	39,506
Depreciation and amortization	60,733	58,721	58,052
Taxes other than income	29,379	31,541	31,345
Operating expenses	144,169	139,762	128,903
Operating income	165,207	171,138	192,748
Interest expense			
Interest expense	43,082	43,218	42,792
Interest expense capitalized	(11)	(137)	(157)
Interest expense, net	43,071	43,081	42,635
Other income (expense)			
Allowance for equity funds used during construction	30	192	269
Other income (Note 10)	2,427	2,218	2,396
Other expense (Note 10)	(488)	(622)	(532)
Other income, net	1,969	1,788	2,133
Net income to partners	$ 124,105	$ 129,845	$ 152,246

NORTHERN BORDER PIPELINE COMPANY
STATEMENTS OF COMPREHENSIVE INCOME

	Years Ended December 31, 2007	2006	2005
	(In thousands)		
Net income to partners	$ 124,105	$ 129,845	$ 152,246
Other comprehensive income:			
Changes associated with hedging transactions	(3,419)	(1,284)	(1,500)
Total comprehensive income	$ 120,686	$ 128,561	$ 150,746

The accompanying notes are an integral part of these financial statements.

NORTHERN BORDER PIPELINE COMPANY
STATEMENTS OF CASH FLOWS

	Years Ended December 31, 2007	2006	2005
	(In thousands)		
CASH FLOW FROM OPERATING ACTIVITIES			
Net income to partners	$ 124,105	$ 129,845	$ 152,246
Adjustments to reconcile net income to partners to net cash provided by operating activities:			
Depreciation and amortization	61,115	59,325	58,404
Allowance for equity funds used during construction	(30)	(192)	(269)
Changes in components of working capital	1,457	1,827	(127)
Other	(2,146)	(5,479)	(3,793)
Total adjustments	60,396	55,481	54,215
Net cash provided by operating activities	184,501	185,326	206,461
CASH FLOW FROM INVESTING ACTIVITIES			
Capital expenditures for property, plant and equipment, net	(10,636)	(20,857)	(28,555)
CASH FLOW FROM FINANCING ACTIVITIES			
Equity contributions from partners	15,000	10,330	—
Distributions to partners	(172,668)	(178,841)	(202,901)
Issuance of debt	269,000	105,000	136,000
Retirement of debt	(273,000)	(112,000)	(109,000)

Debt financing costs	(257)		(321)
Net cash used in financing activities	(161,925)	(175,511)	(176,222)
Net change in cash and cash equivalents	11,940	(11,042)	1,684
Cash and cash equivalents at beginning of year	10,997	22,039	20,355
Cash and cash equivalents at end of year	$ 22,937	$ 10,997	$ 22,039
Supplemental disclosures for cash flow information:			
Cash paid for interest, net of amount capitalized	$ 44,481	$ 45,170	$ 44,067
Changes in components of working capital:			
Accounts receivable	$ (1,234)	$ 8,179	$ (5,694)
Related party receivables	(2,399)	1,939	(983)
Materials and supplies	(235)	(404)	(157)
Prepaid expenses and other	(388)	422	149
Accounts payable	2,602	(5,973)	6,491
Related party payables	3,313	(1,016)	(1,731)
Accrued taxes other than income	54	(66)	524
Accrued interest	(232)	(10)	160
Other current liabilities	(24)	(1,244)	1,114
Total	$ 1,457	$ 1,827	$ (127)

The accompanying notes are an integral part of these financial statements.

NORTHERN BORDER PIPELINE COMPANY
STATEMENTS OF CHANGES IN PARTNERS' EQUITY

	TC PipeLines Intermediate Limited Partnership	ONEOK Partners Intermediate Limited Partnership	Accumulated Other Comprehensive Income (Loss)	Total Partners' Equity
	(In thousands)			
Partners' equity at December 31, 2004	$ 289,014	$ 674,364	$ 3,762	$ 967,140
Net income to partners	45,674	106,572	—	152,246
Changes associated with hedging transactions	—	—	(1,500)	(1,500)
Distributions paid	(60,870)	(142,031)	—	(202,901)
Partners' equity at December 31, 2005	273,818	638,905	2,262	914,985
Net income to partners	57,452	72,393	—	129,845
Changes associated with hedging transactions	—	—	(1,284)	(1,284)
Equity contributions received	3,099	7,231	—	10,330
Distributions paid	(80,420)	(98,421)	—	(178,841)
Ownership change	183,080	(183,080)	—	—
Partners' equity at December 31, 2006	437,029	437,028	978	875,035
Net income to partners	62,052	62,053	—	124,105
Changes associated with hedging transactions	—	—	(3,419)	(3,419)
Equity contributions received	7,500	7,500	—	15,000
Distributions paid	(86,334)	(86,334)	—	(172,668)
Partners' equity at December 31, 2007	$ 420,247	$ 420,247	$ (2,441)	$ 838,053

The accompanying notes are an integral part of these financial statements.

NORTHERN BORDER PIPELINE COMPANY
NOTES TO FINANCIAL STATEMENTS

1. ORGANIZATION AND MANAGEMENT

In this report, references to "we, "us" or "our" collectively refer to Northern Border Pipeline Company.

We are a Texas general partnership formed in 1978. We own a 1,249-mile natural gas transmission pipeline system extending from the United States-Canadian border near Port of Morgan, Montana, to a terminus near North Hayden, Indiana. In April 2006, ONEOK Partners Intermediate Limited Partnership (ONEOK Partners) completed the sale of a 20 percent partnership interest in us to TC PipeLines Intermediate Limited

Partnership (TC PipeLines). As a result of the transaction, our General Partnership Agreement was amended and restated effective April 6, 2006.

The ownership and voting percentages of our partners at December 31, 2007 and 2006 are as follows:

Partner	Ownership
ONEOK Partners	50 %
TC PipeLines	50 %

We are managed by a Management Committee that consists of four members. Each partner designates two members, and TC PipeLines designates one of its members as chairman. The Management Committee designates the members of the Audit Committee, which consists of three members. One member is selected by the members of the Management Committee designated by the partner whose affiliate is the operator and two members are selected by the members of the Management Committee designated by the other partner.

The day-to-day management of our affairs is the responsibility of TransCanada Northern Border, Inc., (TransCanada Northern Border) pursuant to an operating agreement between us and TransCanada Northern Border effective April 1, 2007. TransCanada Northern Border utilizes the services of TransCanada Corporation (TransCanada) and its affiliates for management services related to us. We are charged for the salaries, benefits and expenses of TransCanada and its affiliates attributable to our operations. For the year ended December 31, 2007, our charges from TransCanada and its affiliates totaled approximately $22.5 million.

Prior to April 1, 2007, the day-to-day management of our affairs was the responsibility of ONEOK Partners GP, L.L.C. (ONEOK Partner GP) pursuant to an operating agreement between us and ONEOK Partners GP. ONEOK Partners GP also utilized ONEOK, Inc. (ONEOK) and its affiliates for management services related to us. We were charged for the salaries, benefits and expenses of ONEOK Partners GP, ONEOK and its affiliates attributable to our operations. For the years ended December 31, 2007, 2006, and 2005, our charges from ONEOK Partners GP and its current and former affiliates totaled approximately $9.3 million, $26.2 million and $20.1 million, respectively. Our 2007 charges include $3.6 million for transition related costs. See Note 8 for further discussion of transition related costs.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

The preparation of financial statements in conformity with U.S. generally accepted accounting principles requires management to make assumptions and use estimates that affect the reported amounts of assets, liabilities, revenue and expenses as well as the disclosure of contingent assets and liabilities during the reporting period. Actual results could differ from these estimates if the underlying assumptions are incorrect.

Government Regulation

We are subject to regulation by the Federal Energy Regulatory Commission (FERC). Our accounting policies conform to Statement of Financial Accounting Standards (SFAS) No. 71, “Accounting for the Effects of Certain Types of Regulation.” Accordingly, certain assets and liabilities that result from the regulated ratemaking process are reflected on the balance sheets as regulatory assets and regulatory liabilities.

At December 31, 2007 and 2006, we have reflected regulatory assets of approximately $20.6 million and $19.1 million, respectively, on the balance sheets. These assets are being amortized, as directed by the FERC, over varying time periods up to 43 years.

The following table presents a summary of regulatory assets, net of amortization, at December 31, 2007, and 2006.

	December 31,	
	2007	2006
	(In thousands)	
Fort Peck lease option	$ 10,797	$ 9,507
Pipeline extension project	6,459	6,920
Unamortized loss on reacquired debt	308	376
Deferred rate case expenditures	1,953	2,341
Compressor usage surcharge tracker	1,121	—
Total regulatory assets	$ 20,638	$ 19,144

At December 31, 2007, we have reflected a regulatory liability of $2.4 million on the balance sheet related to negative salvage accrued for estimated net costs of removal of transmission plant. See the Property, Plant and Equipment and Related Depreciation and Amortization policy in this note for further discussion of negative salvage.

We assess the recoverability of costs recognized as regulatory assets and liabilities and the ability to continue to account for our activities based on the criteria set forth in SFAS No. 71, which includes such factors as regulatory changes and the impact of competition. Our review of these criteria currently supports the continuing application of SFAS No. 71. If we cease to meet the criteria of SFAS No. 71, a write-off of related regulatory assets and liabilities could be required.

Revenue Recognition

We transport gas for shippers under a tariff regulated by the FERC. The tariff specifies the maximum rates we may charge shippers and the general terms and conditions of transportation service on our pipeline system. We recognize revenue according to each transportation contract for transportation service that is provided to our customers. Customers with firm service transportation agreements pay a reservation fee for capacity on the pipeline system known as a reservation charge regardless of whether they actually utilize their reserved capacity. Firm service transportation customers also pay a fee known as a commodity charge that is based on the mileage and the volume of natural gas they transport. Customers with interruptible service transportation agreements may utilize available capacity on our pipeline after firm service transportation requests are satisfied. Interruptible service customers are assessed commodity charges based on mileage and the volume of natural gas they transport. An allowance for doubtful accounts is recorded in situations where collectibility is not reasonably assured. We had no allowance for doubtful accounts at December 31, 2007 and 2006. We do not own the gas that we transport, and therefore we do not assume the related natural gas commodity price risk.

Income Taxes

Income taxes are the responsibility of our partners and are not reflected in these financial statements. Our FERC tariff, through December 31, 2006, established the method of accounting for and calculating income taxes which would have been paid or accrued if we were organized during the period as a corporation. Pursuant to the terms of the settlement of our 2005 rate case, during the time period that the rates effective January 1, 2007 are in effect, the treatment historically accorded income taxes will be observed by us for regulatory accounting purposes.

Cash and Cash Equivalents

Cash equivalents consist of highly liquid investments with original maturities of three months or less. The carrying amount of cash and cash equivalents approximates fair value due to the short maturity of these investments.

Property, Plant and Equipment and Related Depreciation and Amortization

Property, plant and equipment is stated at original cost. During periods of construction, we are permitted to capitalize an allowance for funds used during construction, which represents the estimated costs of funds used for construction purposes. The original cost of property retired is charged to accumulated depreciation and amortization. No retirement gain or loss is included in income except in the case of retirements or sales of entire regulated operating units or systems.

Maintenance and repairs are charged to operations in the period incurred. The provision for depreciation and amortization of the transmission line is an integral part of our FERC tariff. As a result of the settlement of our 2005 rate case, the effective depreciation rate applied to our transmission plant in 2007 is 2.40 percent. The effective depreciation rate applied to our transmission plant in 2006 and 2005 was 2.25 percent. The transmission plant depreciation rate in 2007 of 2.40 percent is comprised of two components: one based on economic service life or capital recovery and one based on cost of removal, net of salvage value received, or negative salvage. We accrue the estimated net costs of removal of transmission plant as a regulatory liability, which does not represent an existing legal obligation. The net cost of removal incurred on retirements of transmission plant is recorded as a reduction to the regulatory liability. As of December 31, 2007, $2.4 million for accrued negative salvage is included as a regulatory liability on the accompanying balance sheet. Composite rates are applied to all other functional groups of property having similar economic characteristics. See Note 4 for discussion of our 2005 rate case settlement.

Natural Gas Imbalances

Natural gas imbalances occur when the actual amount of natural gas delivered or received by a pipeline system or storage facility differs from the contractual amount of natural gas scheduled to be delivered or received. We value these imbalances due to or from shippers and interconnecting parties at an appropriate index price. Imbalances are made up in-kind, subject to the terms of our tariff.

Imbalances due from others are reported on the balance sheets as accounts receivable. Imbalances owed to others are reported on the balance sheets as accounts payable. All imbalances are classified as current.

Risk Management

We use financial instruments in the management of our interest rate exposure. A control environment has been established which includes policies and procedures for risk assessment and the approval, reporting and monitoring of financial instrument activities. We do not use these instruments for trading purposes. SFAS No. 133, “Accounting for Derivative Instruments and Hedging Activities,” as amended by SFAS No. 137 and SFAS No. 138, requires that all derivative instruments (including certain derivative instruments embedded in other contracts) be recorded on the balance sheet as either an asset or liability measured at their fair value. We determine the fair value of a derivative instrument by the present value of its future cash flows based on market prices from third party sources. We record changes in the derivative’s fair value currently in earnings unless specific hedge accounting criteria are met. Accounting for qualifying hedges allows a derivative’s gains and losses to offset related results on the hedged item in the income statement, and requires us to formally document, designate and assess the effectiveness of transactions that receive hedge accounting. See Note 7 for a discussion of our derivative instruments and hedging activities.

Unamortized Debt Premium, Discount and Expense

We amortize premiums, discounts and expenses incurred in connection with the issuance of debt consistent with the terms of the respective debt instrument.

Operating Leases

We have non-cancelable operating leases for office space and rights-of-way. We record rent expense over the lease term as it becomes payable. If operating leases include escalating rental payments, we determine the cumulative rental payments anticipated and recognize rent expense on a straight-line basis over the term of the lease.

Impairment of Long-Lived Assets

We assess our long-lived assets for impairment based on SFAS No. 144, “Accounting for the Impairment or Disposal of Long-Lived Assets.” A long-lived asset is tested for impairment whenever events or changes in circumstances indicate that its carrying amount may exceed its fair value. Fair values are based on the sum of the undiscounted future cash flows expected to result from the use and eventual disposition of the assets.

Contingencies

Our accounting for contingencies covers a variety of business activities including contingencies for legal exposures and environmental exposures. We accrue these contingencies when our assessments indicate that it is probable that a liability has been incurred or an asset will not be recovered and an amount can be reasonably estimated in accordance with SFAS No. 5, “Accounting for Contingencies.” We base our estimates on currently available facts and our estimates of the ultimate outcome or resolution. Actual results may differ from our estimates resulting in an impact, positive or negative, on earnings.

Reclassifications

Certain reclassifications have been made to the financial statements for prior years to conform to the current year presentation. These reclassifications did not impact previously reported net income or partners’ equity.

3. ASSET RETIREMENT OBLIGATIONS

Effective January 1, 2003, we adopted SFAS No. 143, “Accounting for Asset Retirement Obligations.” SFAS No. 143 requires entities to record the fair value of a liability for an asset retirement obligation during the period in which the liability is incurred, if a reasonable estimate of fair value can be made. Effective December 31, 2005, we adopted FIN 47, “Accounting for Conditional Asset Retirement Obligations–an interpretation of SFAS No. 143.” FIN 47 clarifies the term “conditional asset retirement obligation,” as used in SFAS No. 143 and the circumstances under which an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation. We have determined that asset retirement obligations exist for certain of our transmission assets; however, the fair value of the obligations cannot be determined because the end of the transmission system life is not determinable with the degree of accuracy necessary to currently establish a liability for the obligations.

4. RATES AND REGULATORY ISSUES

The FERC regulates the rates and charges for transportation of natural gas in interstate commerce. Natural gas companies may not charge rates that have been determined to be unjust and unreasonable by the FERC. Generally, rates for interstate pipelines are based on the cost of service, including recovery of and a return on the pipeline’s actual prudent historical cost investment. The rates and terms and conditions for service are found in each pipeline’s FERC-approved tariff. Under its tariff, an interstate pipeline is allowed to charge for its services on the basis of stated transportation rates. Transportation rates are established periodically in FERC proceedings known as rate cases. The tariff also allows the interstate pipeline to provide services under negotiated and discounted rates.

As required by the provisions of the settlement of our 1999 rate case, on November 1, 2005 we filed a rate case with the FERC. In December 2005, the FERC issued an order that identified issues that were raised in the proceeding and accepted the proposed rates, but suspended their effectiveness until May 1, 2006. Beginning May 1, 2006, the new rates were collected subject to refund through September 30, 2006. Based on the settlement, discussed below, we refunded $10.8 million to our customers in the fourth quarter of 2006.

The settlement of our 2005 rate case was approved by the FERC in November 2006. The settlement established maximum long-term mileage-based rates and charges for transportation on our system. Beginning in 2007, overall rates were reduced, compared with rates prior to the filing, by approximately 5 percent. For the full transportation route from Port of Morgan, Montana to the Chicago area, the previous charge of approximately $0.46 per Dekatherm (Dth) is now approximately $0.44 per Dth, which is comprised of a reservation rate, commodity rate and a compressor usage surcharge. The factors used in calculating depreciation expense for transmission plant were increased from 2.25 percent to 2.40 percent. The settlement also provided for seasonal rates for short-term transportation services. Seasonal maximum rates vary on a monthly basis from approximately $0.54 per Dth to approximately $0.29 per Dth for the full transportation route from Port of Morgan, Montana to the Chicago area. The settlement included a three-year moratorium on filing rate cases and participants challenging these rates, and requires that we file a rate case within six years from the date the new rates went into effect.

The compressor usage surcharge rate is designed to recover the actual costs of electricity at our electric compressors and any compressor fuel use taxes imposed on our pipeline system. Any difference between the compressor usage surcharge collected and the actual costs for electricity and compressor fuel use taxes is recorded as either an increase to expense for an over recovery of actual costs or as a decrease to expense for an under recovery of actual costs, and is included in operations and maintenance expense on the income statement and as either a regulatory liability or a regulatory asset, respectively, on the balance sheet. The compressor usage surcharge rate is adjusted annually. The regulatory liability or regulatory asset will reflect the net over or under recovery of actual compressor usage related costs at the date of the balance sheet. As of December 31, 2007, we had recorded $1.1 million as a regulatory asset on the accompanying balance sheet for the net under recovery of compressor usage related costs.

5. TRANSPORTATION SERVICE AGREEMENTS

Operating revenues are collected pursuant to the FERC tariff through transportation service agreements. Our firm service agreements at December 31, 2007, extend for various terms with termination dates that range from one day to approximately eight years. We also have interruptible transportation service agreements and other transportation service agreements with numerous shippers. Under the capacity release provisions of our FERC tariff, shippers under firm contracts are allowed to release all or part of their capacity either permanently for the full term of the contract or temporarily. A temporary capacity release does not relieve the original contract shipper from its payment obligations if the replacement shipper fails to pay for the capacity temporarily released to it.

At December 31, 2007, our largest shippers, Cargill Inc. (Cargill) and BP Canada Energy Marketing Corp. (BP Canada) were obligated for approximately 15 percent and 14 percent of summer day design capacity, respectively. The Cargill and BP Canada firm service agreements extend for various terms with termination dates ranging from March 2008 to December 2008 and January 2008 to April 2014, respectively.

For the year ended December 31, 2007, shippers providing significant operating revenues were BP Canada, Nexen Marketing U.S.A. Inc. (Nexen) and Cargill with revenues of $49.7 million, $44.1 million, and $42.0 million, respectively. For the year ended December 31, 2006, shippers providing significant operating revenues were BP Canada and Cargill with revenues of $66.7 million and $43.0 million, respectively. For the year ended December 31, 2005, shippers providing significant operating revenues were BP Canada, Nexen, EnCana Marketing (USA) Inc. and Cargill with revenues of $56.1 million, $38.1 million, $37.9 million and $34.1 million, respectively.

For the years ended December 31, 2007, 2006 and 2005, we had contracted firm capacity held by one shipper affiliated with one of our general partners. ONEOK Energy Services Company, LP (ONEOK Energy), a subsidiary of ONEOK, holds firm service agreements representing approximately 3 percent of summer day design capacity at December 31, 2007. The firm service agreements with ONEOK Energy extend for various terms with termination dates that range from March 2008 to November 2011. Revenue from ONEOK Energy for 2007, 2006 and 2005 was $5.1 million, $7.0 million and $7.7 million, respectively. At December 31, 2007 and 2006, we had outstanding receivables from ONEOK Energy of $0.8 million and $0.3 million, respectively.

6. CREDIT FACILITIES AND LONG-TERM DEBT

Detailed information on long-term debt is as follows:

	December 31, 2007	December 31, 2006
	(In thousands)	
2007 Credit Agreement - average interest rate of 5.35% at December 31, 2007 due 2012	$ 166,000	$ —
2005 Credit Agreement - average interest rate of 6.33% at December 31, 2006 refinanced in 2007	—	20,000
1999 Senior Notes – 7.75%, due 2009	200,000	200,000
2001 Senior Notes – 7.50%, due 2021	250,000	250,000
2002 Senior Notes – 6.25%, due 2007	—	150,000
Unamortized debt discount, net of premium	(714)	(156)
Subtotal	615,286	619,844
Current maturities	—	(170,000)
Long-term debt	$ 615,286	$ 449,844

On April 27, 2007, we entered into a $250 million amended and restated revolving credit agreement (2007 Credit Agreement) with certain financial institutions. The 2007 Credit Agreement was used to refinance the outstanding indebtedness under our $175 million revolving credit agreement dated as of May 16, 2005 (2005 Credit Agreement) and was used to repay all of the $150 million of our 6.25 percent Senior Notes due May 1, 2007. The 2007 Credit Agreement can also be used to finance permitted acquisitions, pay related fees and expenses, issue letters of credit and provide for ongoing working capital needs and for other general business purposes, including capital expenditures.

At December 31, 2007, based on the principal commitment amount of $250 million, available capacity under the 2007 Credit Agreement was $84 million. We may, at our option, so long as no default or event of default has occurred and is continuing, elect to increase the capacity under our 2007 Credit Agreement by an aggregate amount not to exceed $100 million, provided that lenders are willing to commit additional amounts. At our option, the interest rate on the outstanding borrowings may be the lenders' base rate or the London Interbank Offered Rate plus a spread that is based on our long-term unsecured credit ratings. The 2007 Credit Agreement permits us to specify the portion of the borrowings to be covered by specific interest rate options and to specify the interest rate period. We are required to pay a facility fee of 0.05 percent based on the principal amount of the commitment of $250 million. The term of the agreement is five years, with options for two one-year extensions.

Certain of our long-term debt arrangements contain certain covenants that restrict the incurrence of secured indebtedness or liens upon property by us. Under the 2007 Credit Agreement, we are required to comply with certain financial, operational and legal covenants. Among other things, we are required to maintain a ratio of total debt to EBITDA (net income plus interest expense, income taxes, depreciation and amortization and all other non-cash charges) of no more than 4.75 to 1. Pursuant to the 2007 Credit Agreement, if one or more acquisitions are consummated in which the aggregate purchase price is $25

million or more, the allowable ratio of total debt to EBITDA is increased to 5.50 to 1 for the first three full calendar quarters following the acquisition. Upon any breach of these covenants, amounts outstanding under the 2007 Credit Agreement may become immediately due and payable. At December 31, 2007, we were in compliance with all of our financial covenants.

Aggregate required repayments of long-term debt for the next five years are $200 million in 2009 and $166 million in 2012. Aggregate required repayments of long-term debt thereafter total $250 million. There are no required repayment obligations for 2008, 2010 or 2011.

The following estimated fair values of financial instruments represent the amount at which each instrument could be exchanged in a current transaction between willing parties. Based on quoted market prices for similar issues with similar terms and remaining maturities, the estimated fair value of the aggregate of the senior notes outstanding at December 31, 2007 and 2006, was approximately $493 million and $623 million, respectively. We presently intend to maintain the current schedule of maturities for the 1999 Senior Notes and the 2001 Senior Notes, which will result in no gains or losses on their respective repayments. The fair value of the 2007 Credit Agreement approximates the carrying value since the interest rates are periodically adjusted to reflect current market conditions.

7. DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

Prior to the anticipated issuance of fixed rate debt, we entered into forward starting interest rate swap agreements. The interest rate swap agreements were designated as cash flow hedges as they hedged the fluctuations in Treasury rates and spreads between the execution date of the swap agreements and the issuance of the fixed rate debt. The notional amount of the interest rate swap agreements did not exceed the expected principal amount of fixed rate debt to be issued. Upon issuance of the fixed rate debt, the swap agreements were terminated and the proceeds received or amounts paid to terminate the swap agreements were recorded in accumulated other comprehensive income and amortized to interest expense over the term of the debt.

During the years ended December 31, 2007, 2006, and 2005, respectively, we amortized approximately $1.6 million, $1.3 million, and $1.5 million related to the terminated interest rate swap agreements as a reduction to interest expense from accumulated other comprehensive income. We expect to amortize approximately $1.5 million as a reduction to interest expense in 2008.

We record in long-term debt amounts received or paid related to terminated interest rate swap agreements for fair value hedges and amortize these amounts to interest expense over the remaining original term of the interest rate swap agreements. During the years ended December 31, 2007, 2006, and 2005, we amortized approximately $0.7 million, $2.1 million and $2.1 million, respectively, as a reduction to interest expense. Amounts received or paid related to terminated interest rate swap agreements for fair value hedges were fully amortized at June 30, 2007.

In August 2007, we entered into a zero cost interest rate collar agreement (the “Collar Agreement”) to limit the variability of the interest rate on $140 million of variable-rate borrowings during the period from October 30, 2007 through October 30, 2009 to a range between a floor of 4.35 percent and a cap of 5.36 percent. We have designated the Collar Agreement as a cash flow hedge. At December 31, 2007, the balance sheet reflected an unrealized loss of approximately $1.9 million with a corresponding decrease to accumulated other comprehensive income (loss) related to the changes in fair value of the Collar Agreement since inception. Since inception, no amounts have been recognized in income due to ineffectiveness or amounts received or paid under the Collar Agreement.

8. COMMITMENTS AND CONTINGENCIES

Operating Leases

Future minimum lease payments under non-cancelable operating leases on office space and rights-of-way are as follows:

	(In thousands)
Year ending December 31,	
2008	2,540
2009	2,541
2010	2,194
2011	1,889
2012	1,889
Thereafter	61,072
	$ 72,125

Expenses incurred related to these lease obligations for the years ended December 31, 2007, 2006 and 2005 were $1.5 million, $0.7 million, and $0.6 million, respectively.

In August 2004, we signed an Option Agreement and Expanded Facilities Lease (Option Agreement) with the Assiniboine and Sioux Tribes of the Fort Peck Indian Reservation. The Option Agreement documented the settlement of certain pipeline and right-of-way lease and taxation issues.

The Option Agreement grants to us, among other things: (i) an option to renew the pipeline right-of-way lease upon agreed terms and conditions on or before April 1, 2011, for a term of 25 years with a renewal right for an additional 25 years; (ii) a right to use additional tribal lands for expanded facilities; and (iii) release and satisfaction of all tribal taxes against us. In consideration of this option and other benefits, we paid a lump sum amount of $7.4 million and will make additional annual option payments of approximately $1.5 million through March 31, 2011.

Transition Related Costs

We are required to pay $3.6 million over a five year period under a transition services agreement between ONEOK Partners GP and TransCanada Northern Border, related to the reimbursement for shared equipment and furnishings acquired by ONEOK Partners and previously used or currently in use for our operations. During the second quarter of 2007 a charge of $2.3 million was recorded in operations and maintenance expense and $1.3 million was recorded as natural gas transmission plant for the shared equipment and furnishings previously used or currently in use by us, respectively. Amounts related to this obligation are included in related party payables on the balance sheet. Future remaining payments for this obligation are as follows:

Year ending December 31,	(In thousands)
2008	753
2009	753
2010	753
2011	753
	$ 3,012

Environmental Matters

We are not aware of any material contingent liabilities with respect to compliance with applicable environmental laws and regulations.

Other

Various legal actions that have arisen in the ordinary course of business are pending. We believe that the resolution of these issues will not have a material adverse impact on our results of operations or financial position.

9. CASH DISTRIBUTION POLICY

Our General Partnership Agreement provides that distributions to our partners are to be made on a pro rata basis according to each partner's capital account balance. Our Management Committee determines the amount and timing of the distributions to our partners including equity contributions and the funding of growth capital expenditures. Any changes to, or suspension of, our cash distribution policy requires the unanimous approval of the Management Committee. Our cash distributions are equal to 100 percent of our distributable cash flow as determined from our financial statements based upon earnings before interest, taxes, depreciation and amortization less interest expense and maintenance capital expenditures. In 2006, upon the closing of the sale of a 20 percent general partnership interest in us from ONEOK Partners to TC PipeLines, our Management Committee adopted certain changes to our cash distribution policy related to financial ratio targets and equity contributions. The change defined minimum equity to total capitalization ratios to be used by the Management Committee to establish the timing and amount of required equity contributions. In addition, any shortfall due to the inability to refinance maturing debt will be funded by equity contributions.

For the years ended December 31, 2007, 2006 and 2005, we paid distributions to our general partners of $172.7 million, $178.8 million and $202.9 million, respectively. In 2007, we issued an equity cash call to our general partners in the amount of $15.0 million for the previously approved 2007 equity cash call. The proceeds were used to repay indebtedness. We issued an equity cash call to our general partners of $10.3 million in 2006 to fund approximately 50 percent of our growth capital expenditures.

10. OTHER INCOME (EXPENSE)

Other income (expense) on the statements of income includes such items as investment income, nonoperating revenues and expenses, and nonrecurring other income and expense items. For the years ended December 31, 2007, 2006 and 2005, other income (expense) included:

	Years Ended December 31,		
	2007	2006	2005
		(In thousands)	
Other income			
Nonoperating revenue	$ 1,638	$ 1,086	$ 1,134
Investment income	691	627	487
Bad debt expense adjustment	—	—	408
Other	98	505	367
Other income	$ 2,427	$ 2,218	$ 2,396
Other expense			
Depreciation and amortization for non-regulated property	$ (382)	$ (604)	$ (351)
Other	(106)	(18)	(181)
Other expense	$ (488)	$ (622)	$ (532)

11. ACCOUNTING PRONOUNCEMENTS

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements," which establishes a framework for measuring fair value and requires additional disclosures about fair value measurements. SFAS No. 157 is effective for our fiscal year beginning January 1, 2008. The effect of adopting SFAS No. 157 is not expected to be material to our results of operations or financial position.

In February 2007, the FASB issued SFAS No. 159 "The Fair Value Option for Financial Assets and Financial Liabilities - Including an Amendment of FASB Statement No. 115," which permits entities to choose to measure selected financial assets and financial liabilities at fair value. The fair value option established by SFAS No. 159 permits all entities to choose to measure eligible items at fair value at specified election dates. A business entity shall report unrealized gains and losses in earnings, on items for which the fair value option has been elected, at each subsequent reporting date. SFAS No. 159 is effective for our fiscal year beginning January 1, 2008. The effect of adopting of SFAS No. 159 is not expected to be material to our results of operations or financial position.

12. SUBSEQUENT EVENTS

We make distributions to our general partners approximately one month following the end of the quarter. A cash distribution of approximately $46.3 million was declared and paid on February 1, 2008 for the fourth quarter of 2007.

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Section 2: EX-2.5 (GENERAL PARTNERSHIP INTEREST PURCHASE AGREEMENT DATED AS OF DECEMBER 20, 2007)

Exhibit 2.5

GENERAL PARTNERSHIP INTEREST

PURCHASE AGREEMENT

BY AND BETWEEN

TCPL TUSCARORA LTD.

AND

TC PIPELINES TUSCARORA LLC

December 20, 2007

INDEX OF DEFINED TERMS

GENERAL PARTNERSHIP INTEREST PURCHASE AGREEMENT

This GENERAL PARTNERSHIP INTEREST PURCHASE AGREEMENT, dated as of December 20, 2007 (this "**Agreement**"), is made and entered into by and between TCPL Tuscarora Ltd., a Nevada corporation ("**Seller**"), and TC Pipelines Tuscarora LLC, a Delaware limited partnership ("**Buyer**").

WHEREAS, Seller owns a 1% general partnership interest in Tuscarora Gas Transmission Company, a Nevada general partnership (the "**Partnership**");

WHEREAS, Seller desires to sell its 1% general partnership interest in the Partnership (the "**Interest**");

WHEREAS, on the terms and subject to the conditions contained in this Agreement, Buyer desires to purchase the Interest from Seller, and Seller desires to sell the Interest to Buyer;

NOW THEREFORE, in consideration of the mutual covenants, representations, warranties and agreements contained herein, and of other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, and intending to be legally bound hereby, the parties hereto hereby agree as follows:

ARTICLE I
DEFINITIONS

1.1 Definitions. As used in this Agreement, the following terms have the meanings specified or referred to in this Section 1.1:

(1) "**Affiliate**" means a Person that directly, or indirectly through one or more intermediaries, controls, or is controlled by, or is under common control with, a specified Person. A Person shall be deemed to control another Person if such first Person possesses, directly or indirectly, the power to direct, or cause the direction of, the management and policies of such other Person, whether through the ownership of voting securities, by Contract or otherwise.

(2) "**Agreement**" shall have the meaning set forth in the preamble to this Agreement.

(3) "**Balance Sheet**" means the audited balance sheet of the Partnership as of December 31, 2006 included in the Financial Statements.

(4) "**Balance Sheet Date**" means December 31, 2006.

(5) "**Base Claim**" shall have the meaning set forth in Section 9.2(b).

(6) "**Basket**" shall have the meaning set forth in Section 9.2(b).

(7) "**Business**" means the business of the Partnership as conducted on the date of this Agreement.

(8) "**Business Day**" means any day other than Saturday, Sunday and any day which is a legal holiday or a day on which banking institutions in the State of New York and Calgary, Alberta are authorized by law or other governmental action to close.

(9) "**Buyer**" shall have the meaning set forth in the preamble to this Agreement.

(10) "**Buyer Claim**" shall have the meaning set forth in Section 9.2(b).

(11) "**Buyer Disclosure Schedule**" means the disclosure schedule of Buyer referred to in, and delivered pursuant to, this Agreement.

(12) "**Buyer Indemnified Parties**" shall have the meaning set forth in Section 9.2(a).

(13) "**Buyer Required Regulatory Approvals**" shall have the meaning set forth in Section 5.3(b).

(14) "**Ceiling**" shall have the meaning set forth in Section 9.2(b).

(15) "**CERCLA**" means the Comprehensive Environmental Response, Compensation and Liability Act of 1980, 42 U.S.C. §9601, et seq., as amended.

(16) "**Claim Notice**" shall have the meaning set forth in Section 9.4(a).

(17) "**Closing**" shall have the meaning set forth in Section 3.1.

(18) "**Closing Consideration**" shall have the meaning set forth in Section 2.2.

(19) "**Closing Date**" shall have the meaning set forth in Section 3.1.

(20) "**Code**" means the Internal Revenue Code of 1986, as amended.

(21) "**Contract**" means any written contract, agreement, indenture, note, bond, mortgage, loan, instrument, lease or license.

(22) “**Current Assets**” with respect to the Partnership, means, as of the applicable date, without duplication, the sum of the following items, each as set forth on the relevant balance sheet of the Partnership, (i) accounts receivable, (ii) other current assets and (iii) prepaid expenses (excluding, for the avoidance of doubt, cash and cash equivalents (including money market funds) and customer deposits), in each case, in accordance with GAAP and as such terms are used in, and calculated on a basis consistent with the Interim Balance Sheet.

(23) “**Current Liabilities**” with respect to the Partnership, means, as of the applicable date, without duplication, the sum of the following items, each as set forth on the relevant balance sheet of the Partnership, (i) accounts payable, (ii) payable to partners, (iii) accrued taxes other than income taxes, (iv) accrued interest and (v) current portion of long-term debt (excluding, for the avoidance of doubt, customer deposits (which are referred to as “other accrued liabilities” in the Interim Balance Sheet)), in each case, in accordance with GAAP and as such terms are used in, and calculated on a basis consistent with the Interim Balance Sheet.

(24) “**Encumbrances**” means any mortgages, deeds of trust, pledges, liens, security interests, conservation easements, deed restrictions, charges and other encumbrances, other than any Permitted Encumbrances.

(25) “**Environmental Laws**” means all federal, state and local laws, including the common law, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders relating to pollution or protection of the environment, natural resources or human health and safety, including laws relating to Hazardous Substances (including ambient air, surface water, groundwater, land, surface and subsurface strata) or otherwise relating to the manufacture, processing, distribution, use, treatment, storage, transport or handling of Hazardous Substances, laws relating to record keeping, notification, disclosure and reporting requirements respecting Hazardous Substances, and laws relating to the management and use of natural resources.

(26) “**Environmental Permits**” shall have the meaning set forth in Section 4.13(a).

(27) “**FERC**” means the Federal Energy Regulatory Commission or any successor thereto.

(28) “**Financial Statements**” means (i) the Balance Sheet and the audited statement of income, partners’ capital and cash flows of the Partnership for the fiscal year ended December 31, 2006 and (ii) the Interim Balance Sheet and the unaudited statement of income, partners’ capital and cash flows of the Partnership for the nine (9) months ended September 30, 2007, including the notes thereto.

(29) “**GAAP**” means generally accepted accounting principles as used in the United States in effect from time to time.

(30) “**Governmental Authority**” means any executive, legislative, judicial, regulatory or administrative agency, body, commission, department, board, court, tribunal, arbitrating body or authority of the United States or any foreign country, or any state, local or other governmental subdivision thereof.

(31) “**Hazardous Substances**” means (i) any petrochemical or petroleum products, radioactive materials, asbestos in any form that is or could become friable, urea formaldehyde foam insulation and transformers or other equipment that contain dielectric fluid which may contain levels of polychlorinated biphenyls, (ii) any chemicals, materials or substances defined as or included in the definition of “hazardous substances,” “hazardous wastes,” “hazardous materials,” “restricted hazardous materials,” “extremely hazardous substances,” “toxic substances,” “contaminants” or “pollutants” or words of similar meaning and regulatory effect under Environmental Laws or (iii) any other chemical, material or substance, exposure to which is prohibited, limited or regulated by or which could give rise to liability under any applicable Environmental Law.

(32) “**Indemnified Party**” shall have the meaning set forth in Section 9.4(a).

(33) “**Indemnifying Party**” shall have the meaning set forth in Section 9.4(a).

(34) “**Independent Accounting Firm**” means a mutually acceptable nationally recognized firm of independent chartered accountants that has not provided services to either Seller or Buyer or any of their Affiliates in the preceding three (3) years, or if no such firm is available and willing to serve, then a mutually acceptable expert in public accounting, in each case, upon which Buyer and Seller shall have mutually agreed.

(35) “**Intellectual Property**” means all: (i) patents and patent applications, registrations and disclosures and all related continuations, divisionals, continuations-in-part, reissues, reexaminations, utility models, certificates of invention and design patents, (ii) trademarks, service marks, trade dress, logos, corporate names, trade names and internet domain names, together with the goodwill associated with any of the foregoing, and all applications and registrations therefor, (iii) copyrights and registrations and applications therefor, copyrightable works of authorship and moral rights, (iv) confidential and proprietary information, including trade secrets, discoveries, concepts, ideas, research and development, financial, marketing and business data, pricing and cost information, business and marketing plans, algorithms, know-how, formulae, inventions (whether or not patentable), processes, techniques, technical data,

designs, drawings, specifications, databases, and customer and supplier lists and information, in each case to the extent confidential and proprietary, excluding any rights in respect of any of the items described in this clause (iv) that comprise or are protected by patents or otherwise by clauses (i)-(iii) and (v) of this definition, and (v) Software.

(36) “**Interest**” shall have the meaning set forth in the recitals to this Agreement.

(37) “**Losses**” shall have the meaning set forth in Section 9.2(a).

(38) “**Material Adverse Effect**” means a material adverse effect on the business, results of operations, ownership, operation, or financial condition of the Partnership or the Business taken as a whole, or that materially impedes the ability of Seller to consummate the transactions contemplated by this Agreement, except for any such effect or impediment (to the extent, in the case of clauses (i), (ii) or (iii), such effect or impediment does not have a disproportionate impact on the Partnership or the Business relative to other entities operating similar businesses) arising out of or relating to (i) any change or effect resulting from the general state of the industries in which the Partnership operates (including (A) changes in pricing levels, (B) changes in the international, national, regional or local wholesale or retail markets for natural gas, (C) changes in the North American, national, regional or local interstate natural gas pipeline systems, or (D) changes in applicable laws, rules, regulations or decisions of the FERC or judgments, orders or decrees of courts affecting the interstate natural gas transmission industry, or rate orders, motions, complaints or other actions affecting the Partnership), (ii) any change or effect resulting from changes in the international, national, regional or local markets for any supplies used by the Business, (iii) any change or effect resulting from changes in general economic, political or business conditions (including changes in interest rates or debt, equity, financial, banking or currency markets), (iv) any change or effect resulting from any change in GAAP, (v) any change or effect resulting from the negotiation, execution, announcement, pendency or consummation of the transactions contemplated by this Agreement, including the impact thereof on relationships, contractual or otherwise, with customers, suppliers, distributors, partners, joint owners or venturers, or employees, other than Sierra Pacific Resources and its Affiliates, (vi) any change or effect resulting from any action taken by Seller, the Partnership, Buyer or any of their respective Representatives or Affiliates or other action required, contemplated or permitted by this Agreement or consented to by Buyer, (vii) any change or effect resulting from acts of war, armed hostilities or terrorism, (viii) any change or effect resulting from changes in weather or climate, (ix) any materially adverse change in or effect on the Business which is cured (including by the payment of money) before the Termination Date, or (x) any circumstance, matter or condition described in the Seller Disclosure Schedule.

(39) “**Material Contracts**” shall have the meaning set forth in Section 4.15 of this Agreement

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(40) “**Material Leases**” shall mean, as of the date of this Agreement, all leases under which the Partnership is a lessee, lessor or under which the Partnership otherwise has any interest (i) with annual payments greater than $250,000 or (ii) which are otherwise material to the Business.

(41) “**New York Courts**” shall have the meaning set forth in Section 10.5(e).

(42) “**Notice Period**” shall have the meaning set forth in Section 9.4(a).

(43) “**Operating Agreement**” means the Operating Agreement, dated as of the 19th day of December, 2006 by and between the Partnership and TransCanada Northern Border Inc., (formerly TransCan Northwest Border Ltd.), as amended by the First Amendment to Operating Agreement dated June 21, 2007.

(44) “**Partnership**” shall have the meaning set forth in the recitals to this Agreement.

(45) “**Partnership Agreement**” means the Tuscarora Gas Transmission Company General Partnership Agreement, dated as of June 11, 1993, by and between Seller and Buyer, as amended by that First Amendment to General Partnership Agreement, dated as of September 1, 2000, as amended by that Second Amendment to General Partnership Agreement, dated as of December 17, 2003, as amended by that Third Amendment to General Partnership Agreement, dated as of November 22, 2006, as amended by that Fourth Amendment to General Partnership Agreement, dated as of December 21, 2006 and as may be further amended from time to time.

(46) “**Permits**” shall have the meaning set forth in Section 4.17.

(47) “**Permitted Encumbrances**” means (i) all exceptions, restrictions, easements, covenants, charges, permits, servitudes, rights of way and Encumbrances of record or that are set forth in an applicable FERC project license or title insurance policy, provided that Seller has provided or made available a copy of such license or insurance policy to Buyer, (ii) all matters of record and any state of facts that a current survey or inspection of the Real Property would disclose and which do not materially and adversely affect the ability of the Partnership to conduct the Business as presently conducted, (iii) mortgages, liens, pledges, charges, Encumbrances and restrictions incurred in connection with the Partnership’s purchase of properties and assets after the Balance Sheet Date securing all or a portion of the purchase price therefor, (iv) statutory Encumbrances for Taxes, assessments or other governmental charges not yet due and payable or that may be subsequently paid without penalty or interest or that are being contested in good faith in (if then appropriate) appropriate proceedings, (v) mechanics’, carriers’, workers’, repairman’s, materialman’s,

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warehousemen’s, employees’, landlord’s, construction and other similar Encumbrances arising or incurred in the ordinary course of business consistent with past practice relating to obligations that are not yet due and payable or that are being contested in good faith in (if then appropriate) appropriate proceedings, (vi) requirements and restrictions under zoning, planning, building, entitlement, conservation, land use and environmental laws and regulations (including municipal bylaws and permits, consents and authorizations under such laws and regulations), and development, site plan, subdivision or other agreements with municipalities which do not materially and adversely affect the ability of the Partnership to conduct the Business as presently conducted, (vii) Encumbrances contemplated by or set forth in the Partnership Agreement or the Operating Agreement, (viii) the rights of lessors, lessees, licensors and licensees under leases or licenses of the Real Property, and (ix) such other liens, defects, irregularities, imperfections in or failure of title, charges, easements, restrictions and other Encumbrances which would not, individually or in the aggregate, have a Material Adverse Effect.

(48) "**Person**" means any individual, partnership, joint venture, corporation, limited liability company, limited liability partnership, trust, unincorporated organization or Governmental Authority or any department or agency thereof.

(49) "**Prime Rate**" means the U.S. prime rate of interest published in the "Money Rates" column of the Eastern Edition of The Wall Street Journal on the Closing Date.

(50) **"Purchase Price"** shall have the meaning set forth in Section 2.2.

(51) "**Real Property**" has the meaning set forth in Section 4.9.

(52) "**Representatives**" means with respect to a particular Person, any agent, consultant, advisor, accountant, financial advisor, legal counsel or other representative of that Person.

(53) "**Seller**" shall have the meaning set forth in the preamble to this Agreement.

(54) "**Seller Claim**" shall have the meaning set forth in Section 9.3(b).

(55) "**Seller Disclosure Schedule**" means the disclosure schedule of Seller referred to in, and delivered pursuant to, this Agreement.

(56) "**Seller Indemnified Parties**" shall have the meaning set forth in Section 9.3(a).

(57) "**Seller's Knowledge**" means the actual knowledge of Jeffrey R. Rush, Vice-President and General Manager and Jay G. Story, General Manager, after reasonable inquiry of each of their respective direct reports.

(58) "**Seller Required Regulatory Approvals**" shall have the meaning set forth in Section 4.3(b).

(59) "**Software**" means any and all (i) computer programs, including any and all software implementations of algorithms, models and methodologies, whether in source code or object code, (ii) databases and compilations, including any and all data and collections of data, whether machine readable or otherwise, (iii) descriptions, flow-charts and other work product used to design, plan, organize and develop any of the foregoing, screens, user interfaces, report formats, firmware, development tools, templates, menus, buttons and icons, and (iv) all documentation, including user manuals and other training documentation, related to any of the foregoing.

(60) "**Subsidiary**" of any Person (the "Subject Person") means any Person, whether incorporated or unincorporated, of which (i) at least 50% of the securities or ownership interests having by their terms ordinary voting power to elect a majority of the board of directors or other Persons performing similar functions, (ii) a general partner interest or (iii) a managing member interest, is directly or indirectly owned or controlled by the Subject Person or by one or more of its respective Subsidiaries.

(61) "**Survival Period**" shall have the meaning set forth in Section 9.1(c).

(62) "**Tax**" means any tax, charge, fee, levy, penalty or other assessment imposed by any U.S. federal, state, local or foreign Taxing Authority, including any excise, property, income, sales, transfer, franchise, payroll, withholding, social security or other tax, including any interest, penalties or additions attributable thereto.

(63) "**Tax Return**" means any return, report, information return, declaration, claim for refund or other document (including any related or supporting information) supplied or required to be supplied to any authority with respect to Taxes and including any supplement or amendment thereof.

(64) "**Taxing Authority**" means the Internal Revenue Service and any other Governmental Authority responsible for the administration of any Tax.

(65) "**Termination Date**" shall have the meaning set forth in Section 8.1(b).

(66) "**Third Party Claim**" shall have the meaning set forth in Section 9.4(a).

(67) "**Transfer Taxes**" means any and all transfer Taxes, including sales, use, excise, stock, stamp, documentary, filing, recording, permit, license, authorization and similar Taxes, fees, duties, levies, customs, tariffs, imposts, assessments, obligations and charges.

ARTICLE II
PURCHASE AND SALE OF GENERAL PARTNERSHIP INTEREST

2.1 Purchase and Sale. Upon the terms and subject to the satisfaction (or waiver, if permitted) of the conditions contained in this Agreement, Buyer agrees to purchase from Seller and Seller agrees to sell, assign, convey, transfer and deliver to Buyer, the Interest.

2.2 Purchase Price. Pursuant to Article III, at the Closing, Buyer shall pay, in consideration for the purchase of the Interest pursuant to Section 2.1, in cash the sum of (i) (A) the purchase price paid by TC Tuscarora Intermediate Limited Partnership to Tuscarora Gas Pipeline Co. ("TGP"), December 19, 2006 for TGP's 49% interest in the Partnership, divided by (B) 0.98, multiplied by (C) 0.02, plus (ii) the aggregate amount of any capital contributions in respect of the Interest paid by Seller from and after the December 19, 2006 and prior to the Closing, minus (iii) the aggregate amount of any distributions paid by the Partnership to Seller in respect of the Interest from and after December 19, 2006 and prior to the Closing, (the "Closing Consideration").

ARTICLE III
THE CLOSING

3.1 Time and Place of Closing. Upon the terms and subject to the satisfaction (or waiver, if permitted) of the conditions contained in this Agreement, the closing of the transactions contemplated by this Agreement (the "**Closing**") shall take place at the offices of TransCanada Corporation, 450 – 1st Street SW Calgary, Alberta, at 10:00 a.m., local time, no later than the third Business Day following the date on which all of the conditions to each party's obligations hereunder have been satisfied or waived (other than those conditions that by their nature have to be satisfied at the Closing (but subject to the satisfaction or waiver (if permitted) of those conditions)), or at such other place or time as the parties may agree. The date and time at which the Closing actually occurs is hereinafter referred to as the "**Closing Date**."

3.2 Deliveries by Seller . At the Closing, Seller shall deliver to Buyer the following:

(a) An assignment and assumption agreement duly executed by Seller in respect of the Interest;

(b) The certificate referred to in Section 7.2(c);

(c) An affidavit of non-foreign status from Seller that complies with Section 1445 of the Code; and

(d) Such other agreements, documents, instruments and writings as are required to be delivered by Seller at or prior to the Closing Date pursuant to this Agreement or otherwise required in connection herewith.

3.3 Deliveries by Buyer. At the Closing, Buyer shall deliver to Seller the following:

(a) An assignment and assumption agreement duly executed by Buyer in respect of the Interest;

(b) The Closing Consideration by wire transfer of immediately available funds or by such other means as may be mutually agreed to by Seller and Buyer;

(c) The certificate referred to in Section 7.3(c); and

(d) Such other agreements, documents, instruments and writings as are required to be delivered by Buyer at or prior to the Closing Date pursuant to this Agreement or otherwise required in connection herewith.

ARTICLE IV
REPRESENTATIONS AND WARRANTIES OF SELLER

Except as set forth in the Seller Disclosure Schedule, Seller hereby represents and warrants to Buyer, as of the date of this Agreement, as follows:

4.1 Organization; Qualification. The Partnership is a general partnership duly organized, validly existing and in good standing under the laws of the State of Nevada and has all requisite general partnership power and authority to own, lease, and operate its properties and to carry on the Business as it is now being conducted. The Partnership is duly qualified or licensed to do business as a foreign general partnership and is in good standing in each jurisdiction set forth in Section 4.1 of the Seller Disclosure Schedule, which are the only jurisdictions in which the property owned, leased or operated by it or the nature of the Business conducted by it makes such qualification necessary, except where the failure to be so duly qualified or licensed and in good standing would not have or be reasonably expected to have, individually or in the aggregate, a Material Adverse Effect. A complete and correct copy of the Partnership Agreement as currently in effect has been made available to Buyer.

4.2 Authority Relative to this Agreement. Seller has the corporate power and authority to execute and deliver this Agreement and to consummate the transactions contemplated hereby. The execution, delivery and performance by Seller of this Agreement and the consummation by Seller of the transactions contemplated hereby have been duly and validly authorized by Seller and no other corporate proceedings on the part of Seller are necessary to authorize this Agreement or to consummate the transactions contemplated hereby. This Agreement has been duly executed and delivered by Seller and, assuming that this Agreement constitutes legal, valid and binding agreement of Buyer, constitutes a legal, valid and binding agreement of Seller,

and is enforceable against Seller in accordance with its terms, except that such enforceability may be limited by applicable bankruptcy, insolvency, moratorium or other similar laws affecting or relating to enforcement of creditors' rights generally or general principles of equity.

4.3 Consents and Approvals; No Violation.

(a) Except as set forth in Section 4.3(a) of the Seller Disclosure Schedule, and other than obtaining the Seller Required Regulatory Approvals and the Buyer Required Regulatory Approvals, the execution, delivery and performance of this Agreement by Seller and the consummation by Seller of the transactions contemplated hereby will not (i) conflict with or result in any breach of any provision of the articles of incorporation or bylaws of Seller, (ii) result in a violation or default (with or without notice or lapse of time, or both) or give rise to any right of termination, cancellation or acceleration of any obligation or to loss of a benefit under any of the terms, conditions or provisions of any Permit, Contract or other instrument or obligation to which Seller or the Partnership is a party or by which their respective assets may be bound or (iii) violate or breach any law, order, injunction, decree, statute, rule or regulation applicable to Seller or the Partnership, except, in the case of clauses (ii) and (iii) above, for violations, defaults, or rights of termination, cancellation or acceleration, losses of benefits or breaches which would not have or be reasonably expected to have, individually or in the aggregate, a Material Adverse Effect.

(b) Except as set forth in Section 4.3(b) of the Seller Disclosure Schedule (the filings and approvals referred to in Section 4.3 (b) of the Seller Disclosure Schedule are collectively referred to as the "**Seller Required Regulatory Approvals**"), no material declaration, filing or registration with, or notice to, or authorization, consent or approval of any Governmental Authority (other than the Permits and Environmental Permits) is necessary for the consummation by Seller of the transactions contemplated by this Agreement.

4.4 Capitalization. Section 4.4 of the Seller Disclosure Schedule sets forth all of the outstanding and authorized general partnership interests of the Partnership and all such interests are owned by the Persons as described in such Section of the Seller Disclosure Schedule. The Interest has been duly authorized and validly issued, and is fully paid and nonassessable, and is held of record and beneficially owned by Seller. Except as set forth in Section 4.4 of the Seller Disclosure Schedule or in the Partnership Agreement, there are no preemptive rights, rights of first refusal or any outstanding subscriptions, options, warrants or similar agreements of any kind to which Seller or the Partnership is party or by which the Partnership is bound obligating it to issue, deliver or sell additional general partnership interests or any securities convertible or exchangeable into general partnership interests, or obligating the Partnership to grant, extend or enter into any such subscription, option, warrant or agreement. At the Closing, Seller will transfer to Buyer good title to the Interest, free and clear of Encumbrances (other than Encumbrances created by Buyer or arising under applicable securities laws). The Partnership does not own, directly or indirectly, any capital stock or equity securities of any Person.

4.5 Financial Statements. Seller has delivered or made available copies to Buyer of the Financial Statements. The Financial Statements were prepared in accordance with GAAP, consistently applied (except as disclosed in the notes thereto), and fairly present, in all material respects, the financial position and results of operations of the Partnership as of the dates thereof and for the periods covered thereby.

4.6 Undisclosed Liabilities. Except as set forth in Section 4.6 of the Seller Disclosure Schedule, the Partnership has no material liability relating to the Business of a nature required by GAAP to be reflected in a balance sheet of the Partnership or the notes thereto) except for those liabilities (a) accrued or reserved against in the Interim Balance Sheet or disclosed in the notes thereto, (b) incurred in the ordinary course of business consistent with past practice after the Balance Sheet Date or (c) incurred in accordance with Section 6.1 after the date of this Agreement.

4.7 Absence of Certain Changes or Events. Except as set forth in Section 4.7 of the Seller Disclosure Schedule, since the Balance Sheet Date to the date of this Agreement, (a) there has not been any event, change, occurrence or circumstances that has had, or would reasonably be expected to have, a Material Adverse Effect, (b) the Partnership has conducted the Business only in the ordinary course consistent with past practice and (c) the Partnership has not suffered any loss, damage, destruction or other casualty to any of its property, plant, equipment or inventories (whether or not covered by insurance) in excess of $500,000.

4.8 Compliance with Law. Except for Environmental, Permits and Tax matters, which are the subject of Section 4.13, Section 4.17 and Section 4.18, respectively, and except as set forth in Section 4.8 of the Seller Disclosure Schedule, since January 1, 2006, each of Seller (solely with respect to the Business) and the Partnership has complied with all laws, statutes, ordinances, rules and regulations of any Governmental Authority applicable to its properties, assets and Business, except where such noncompliance would not have or be reasonably expected to have, individually or in the aggregate, a Material Adverse Effect. Since January 1, 2006, neither Seller (solely with respect to the Business) nor the Partnership has received notice of any material violation of any such law, statute, ordinance, rule or regulation. To Seller's Knowledge, neither Seller (solely with respect to the Business) nor the Partnership is under any investigation by any Governmental Authority with respect to the material violation of any such laws, statutes, ordinances, rules and regulations of any Governmental Authority.

4.9 Title to Real Property. Except as set forth in Section 4.9 of the Seller Disclosure Schedule, the Partnership has valid and indefeasible title to or holds a valid, binding and enforceable leasehold, license or other interest in, or right-of-way or easement through, all real property used by the Partnership in the ordinary course of business consistent with past practice (the "**Real Property**"), in each case free and clear of all Encumbrances.

4.10 Intellectual Property. Section 4.10 of the Seller Disclosure Schedule sets forth an accurate and complete list of all material registrations or applications for registration for United States copyrights, patents, or trademarks or

servicemarks (including Internet domain names) owned by the Partnership, including the jurisdiction and record owner of each application or registration. Except as would not have or reasonably be expected to have, individually or in the aggregate, a Material Adverse Effect, or as set forth on Section 4.11 of the Seller Disclosure Schedule, to Seller's Knowledge, (a) the Partnership owns or has valid rights to use all Intellectual Property necessary to operate the Business as currently conducted and (b) there are no pending or threatened written claims that (i) the Partnership is in violation of, infringing upon, diluting or misappropriating any Intellectual Property rights of any third Person or (ii) challenge the validity, enforceability or ownership of any material Intellectual Property owned by the Partnership. To Seller's Knowledge, no third Person is infringing, violating, diluting, or misappropriating any of the material Intellectual Property owned by the Partnership.

4.11 Material Leases. Section 4.11 of the Seller Disclosure Schedule sets forth a list of all Material Leases, including the name of the third party and the date of the lease or sublease and all amendments thereto, as of the date of this Agreement. Except as set forth in Section 4.11 of the Seller Disclosure Schedule, (a) each Material Lease is valid, binding and enforceable in accordance with its terms, and is in full force and effect, (b) the Partnership has not received any notice of material default of the Partnership under any Material Lease in the 12-month period prior to the date of this Agreement and (c) to Seller's Knowledge, there are no uncured defaults of the Partnership under any Material Lease that would give the counterparty thereof the right to terminate such Material Lease.

4.12 Insurance. Section 4.12 of the Seller Disclosure Schedule sets forth a list of all insurance policies and all fidelity bonds held by or applicable to Seller (solely with respect to the Business) and the Partnership setting forth, in respect of each such policy, the policy name, policy number, carrier, term, type and amount of coverage and annual premium. Except as set forth in Section 4.12 of the Seller Disclosure Schedule, all material policies of fire, liability, workers' compensation and other forms of insurance purchased or held by and insuring the Partnership or the Business are in full force and effect, all premiums with respect thereto have been paid, and no written notice of cancellation or termination has been received with respect to any such policy which was not replaced on substantially similar terms prior to the date of such cancellation.

4.13 Environmental Matters. (a) Except as set forth in Section 4.13(a) of the Seller Disclosure Schedule, the Partnership holds, and is in substantial compliance with, all material permits, licenses and governmental authorizations (the "**Environmental Permits**") required for the Partnership to operate the Business under applicable Environmental Laws, and the Partnership is otherwise in compliance with applicable Environmental Laws with respect to the Business except for such failures to hold or comply with required Environmental Permits, or such failures to be in compliance with applicable Environmental Laws, which would not have or be reasonably expected to have, individually or in the aggregate, a Material Adverse Effect.

(b) Except as set forth in Section 4.13(b) of the Seller Disclosure Schedule, the Partnership has not received any written request for information, or been

notified in writing that it is a potentially responsible party, under CERCLA or any similar state law with respect to the Business.

(c) Except as set forth in Section 4.13(c) of the Seller Disclosure Schedule, the Partnership has not entered into or agreed to any material consent, decree or order, and is not subject to any judgment, decree, or judicial order relating to compliance with any Environmental Law or the investigation or cleanup of Hazardous Substances under any Environmental Law which is outstanding and imposes material obligations on the Partnership.

(d) To Seller's Knowledge, no facts, circumstances or conditions exist that would reasonably be expected to result in liability under any Environmental Law having a Material Adverse Effect.

(e) Seller has delivered or made available to Buyer copies of all reports, assessments, investigations, or correspondence related to the Partnership in each case that relate to environmental matters and are material to the extent in the possession, custody, or control of Seller.

(f) Save and except for those representations and warranties in Section 4.3, the representations and warranties made in this Section 4.13 are Seller's exclusive representations and warranties relating to environmental matters.

4.14 Employee Matters. There are no employees of the Partnership and no employee or employee-benefit related liabilities of the Partnership.

4.15 Material Contracts. (a) Section 4.15(a) of the Seller Disclosure Schedule sets forth a list of all Contracts to which the Seller (solely with respect to the Business) or the Partnership, as applicable, is a party as of the date of this Agreement (excluding, for the avoidance of doubt, any such Contracts that are no longer in effect):

(i) for joint ventures, strategic alliances, partnerships, material licensing agreements (excluding licenses of generally available or commercial Software), or sharing of profits;

(ii) containing (i) covenants of the Partnership not to compete with any Person in any line of business or in any geographical area or (ii) covenants of any other Person not to compete with the Partnership in any line of business or in any geographical area;

(iii) with respect to all price swaps, hedges, futures or similar instruments;

(iv) with any current or former officer, director, stockholder, member, partner (or immediate family member thereof) of Seller, any Seller Affiliate or the Partnership;

(v) for the sale of any of the material assets of the Partnership other than in the ordinary course of business consistent with past practice or for the grant to any Person of any preferential rights to purchase any of its material assets;

(vi) for the acquisition (by merger, purchase of stock or assets or otherwise) by the Partnership of any operating business or the capital stock of any other Person;

(vii) for the incurrence, assumption or guarantee of any indebtedness for borrowed money of the Partnership or imposing an Encumbrance on any of the assets of the Partnership in connection therewith, including indentures, guarantees, loan or credit agreements, sale and leaseback agreements, purchase money obligations incurred in connection with the acquisition of property, mortgages, pledge agreements, security agreements, or conditional sale or title retention agreements;

(viii) providing for payments by or to the Partnership in excess of $250,000 in any fiscal year or $500,000 in the aggregate during the term thereof; provided that the calculation of the aggregate payments for any such Contract shall not include payments attributable to any renewal periods or extensions for which the Partnership may exercise an option in its sole discretion to approve or disapprove;

(ix) under which the Partnership has made advances or loans to any other Person;

(x) providing for severance, retention, change in control or other similar payments; and

(xi) providing for the guaranty, surety or indemnification, direct or indirect, by the Partnership, which reasonably could be expected to result in liability to the Partnership in excess of $500,000 (each document set forth on Section 4.16-A of the Seller Disclosure Schedule, being a "**Material Contract**").

(b) Except as disclosed in <u>Section 4.15 of the Seller Disclosure Schedule</u>, (a) each Material Contract is valid, binding and enforceable in accordance with its terms, and is in full force and effect, (b) neither Seller nor the Partnership has received or is aware of any notice of its default under any Material Contract in the 12-month period prior to the date of this Agreement, (c) there are no uncured defaults of Seller or the Partnership under any Material Contract that would give the counterparty thereof the right to terminate such Material Contract, (d) no party to any of the Material Contracts has exercised any termination rights with respect thereto and (e) no party has given written notice of any significant dispute with respect to any Material Contract. Seller has delivered or made available to Buyer correct and complete copies of all of the Material

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Contracts, together with all amendments, modifications or supplements thereto. Neither Seller (solely with respect to the Business) nor the Partnership is a party to any material oral contract, agreement or arrangement.

4.16 <u>Legal Proceedings, etc</u>. Except as set forth in <u>Section 4.16 of the Seller Disclosure Schedule</u>, there are no material claims, actions, or proceedings pending or, to Seller's Knowledge, threatened against Seller or the Partnership relating to the Business, or any of their respective officers, directors or employees with respect to their business activities on behalf of the Partnership, by or before any Governmental Authority, including any claims, actions or proceedings relating to this Agreement or the transactions contemplated hereby, which, if adversely determined, would have or be reasonably expected to have, individually or in the aggregate, a Material Adverse Effect. Except as set forth in <u>Section 4.16 of the Seller Disclosure Schedule</u>, neither Seller (solely with respect to the Business) nor the Partnership is (a) subject to any outstanding judgment, rule, order, writ, injunction or decree of any Governmental Authority relating to the Business which would have or be reasonably expected to have, individually or in the aggregate, a Material Adverse Effect or (b) engaged in any legal action to recover monies due it or for damages sustained by it.

4.17 <u>Permits</u>. The Partnership has all permits, licenses, franchises and other governmental authorizations, consents and approvals, other than with respect to Environmental Laws, necessary to operate the Business as presently operated (collectively, "**Permits**"), except where the failure to have such Permits would not have or be reasonably expected to have, individually or in the aggregate, a Material Adverse Effect. Except as set forth in <u>Section 4.17(b) of the Seller Disclosure Schedule</u>, (a) neither Seller (solely with respect to the Business) nor the Partnership has received any notification that it is in material violation of any Permits, (b) the Partnership is in compliance with all Permits and (c) all material Permits are in good standing, have not expired, are final and non-appealable and, to Seller's Knowledge, are not subject to any threat of revocation, amendment or modification, except, in the case of clause (b) and (c), as would not have or be reasonably expected to have, individually or in the aggregate, a Material Adverse Effect.

4.18 Taxes. (a) To Seller's Knowledge, (i) the Partnership has filed all material Tax Returns required to be filed; (ii) such Tax Returns are true, correct and complete in all material respects; and (iii) the Partnership has fully and timely paid all Taxes shown to be due on such Tax Returns. With respect to any period for which Tax Returns have not yet been filed or for which Taxes are not yet due or owing, the Partnership has made due and sufficient accruals for such Taxes in the Financial Statements and its books and records. To Seller's Knowledge, no claim has been made in writing by a Taxing Authority in a jurisdiction in which the Partnership does not currently file a Tax Return that the Partnership is or may be subject to taxation by that jurisdiction. Neither Seller nor, to Seller's Knowledge, the Partnership has received any written notice of deficiency or assessment from any Taxing Authority with respect to (i) liabilities for material Taxes of the Partnership, which have not been fully and timely paid or finally settled, unless such liabilities are being diligently contested in good faith through appropriate proceedings and provided adequate reserves have been established in

accordance with GAAP in the Financial Statements of the Partnership, or (ii) adjustments to taxable income of the Partnership which have not been finally resolved. To Seller's Knowledge, no Tax Return of the Partnership is currently being audited or examined by any Taxing Authority, and neither Seller nor, to Seller's Knowledge, the Partnership has received any written notice that any Taxing Authority intends to conduct an audit or investigation with respect to any such Tax Return. There are no outstanding (i) agreements or waivers extending the applicable statutory periods of limitation for Taxes of the Partnership, (ii) extensions for the assessment or collection of Taxes of the Partnership, which Taxes have not since been paid, or (iii) powers of attorney that are currently in force with respect to any Tax matter with respect to the Partnership, for any period. The Partnership has qualified as, and has been treated as, a partnership for U.S. federal income Tax purposes at all times since the date of its formation.

(b) The Partnership has complied in all material respects with all applicable laws relating to the payment and withholding of Taxes and has duly and timely withheld and paid over to the appropriate Taxing Authority all amounts required to be so withheld and paid under all applicable laws.

(c) Neither Seller nor, to Seller's Knowledge, the Partnership has executed or entered into any written agreement with, or obtained or applied for any written consents or written clearances or any other Tax rulings from, nor has there been any written agreement executed or entered into on behalf of either of them with, any Taxing Authority, including any IRS closing agreements pursuant to Section 7121 of the Code or any similar provision of law, private letter rulings or comparable rulings of any Taxing Authority.

(d) Seller is not a foreign person within the meaning of Section 1445 of the Code.

4.19 Brokers' Fee. No broker, finder or similar intermediary has acted for or on behalf of, or is entitled to any broker, finder or similar fee or other commission from Seller or any of its Affiliates in connection with this Agreement or the transactions contemplated hereby.

ARTICLE V
REPRESENTATIONS AND WARRANTIES OF BUYER

Except as set forth in the Buyer Disclosure Schedule, Buyer hereby represents and warrants to Seller, as of the date of this Agreement, as follows:

5.1 Organization. Buyer is a limited liability company duly organized, validly existing and in good standing under the laws of the State of Delaware and has all requisite corporate power and authority to own, lease and operate its properties and to carry on its business as now being conducted. Complete and correct copies of Buyer's certificate of formation (or other similar governing documents) as currently in effect have heretofore been delivered or made available to Seller.

5.2 Authority Relative to this Agreement. Buyer has the corporate power and authority to execute and deliver this Agreement and to consummate the transactions contemplated hereby. The execution, delivery and performance by Buyer of this Agreement and the consummation by Buyer of the transactions contemplated hereby have been duly and validly authorized by Buyer and no other corporate proceedings on the part of Buyer are necessary to authorize this Agreement or to consummate the transactions contemplated hereby. This Agreement has been duly executed and delivered by Buyer, and assuming that this Agreement constitutes a legal, valid and binding agreement of Seller, constitutes a legal, valid and binding agreement of Buyer, and is enforceable against Buyer in accordance with its terms, except that such enforceability may be limited by applicable bankruptcy, insolvency, moratorium or other similar laws affecting or relating to enforcement of creditors' rights generally or general principles of equity.

5.3 Consents and Approvals; No Violation. (a) Except as set forth in Section 5.3(a) of the Buyer Disclosure Schedule, and other than obtaining the Buyer Required Regulatory Approvals and the Seller Required Regulatory Approvals, the execution, delivery and performance of this Agreement by Buyer and the consummation by Buyer of the transactions contemplated hereby will not (i) conflict with or result in any breach of any provision of the certificate formation (or similar organizational documents) of Buyer, (ii) result in a violation or default (with or without notice or lapse of time, or both) or give rise to any right of termination, cancellation or acceleration of any obligation or to loss of a benefit under any of the terms, conditions or provisions of any Permit, Contract, or other instrument or obligation to which Buyer is a party or by which its assets may be bound or (iii) violate or breach any law, order, injunction, decree, statute, rule or regulation applicable to Buyer, except, in the case of clauses (ii) and (iii) above, for violations, defaults, or rights of termination, cancellation or acceleration, losses of benefits or breaches which would not or would not be reasonably expected to, individually or in the aggregate, materially impair Buyer's ability to perform its obligations under this Agreement or consummate the transactions contemplated hereby or thereby.

(b) Except as set forth in Section 5.3(b) of the Buyer Disclosure Schedule (the filings and approvals referred to in Section 5.3(b) of the Buyer Disclosure Schedule are collectively referred to as the "**Buyer Required Regulatory Approvals**"), no material declaration, filing or registration with, or notice to, or authorization, consent or approval of any Governmental Authority is necessary for the consummation by Buyer of the transactions contemplated hereby.

5.4 Availability of Funds. On the Closing Date, Buyer will have immediately available funds sufficient to consummate the transactions contemplated by this Agreement.

5.5 Acquisition for Investment; Due Diligence. Buyer is an informed and sophisticated purchaser experienced in financial and business matters and the evaluation and investment in businesses such as the Business as contemplated hereunder. Buyer is acquiring the Interest for investment and not with a view toward or for sale in

connection with any distribution thereof in violation of applicable securities laws. Buyer agrees that the Interest may not be sold, transferred, offered for sale, pledged, hypothecated or otherwise disposed of without registration under the Securities Act of 1933, as amended, except pursuant to an exemption from such registration available under such Act. Buyer has undertaken such investigation and has been provided with and has evaluated such documents and information as it has deemed necessary to enable it, when considered together with the representations and warranties and covenants of Seller set forth herein, to make an informed and intelligent decision with respect to the execution, delivery and performance of this Agreement. Buyer has been furnished the materials relating to Buyer's purchase of the Interest that it has requested, and that Seller has provided Buyer the opportunity to ask questions of the officers and management employees of the Business and to acquire additional information about the Business and financial condition of the Business.

5.6 Brokers' Fee. No broker, finder or similar intermediary has acted for or on behalf of, or is entitled to any broker, finder or similar fee or other commission from Buyer or any of its Affiliates in connection with this Agreement or the transactions contemplated hereby.

ARTICLE VI
COVENANTS OF THE PARTIES

6.1 Conduct of Business of the Partnership. Except as set forth in Section 6.1-A of the Seller Disclosure Schedule, during the period from the date of this Agreement to the Closing Date, Seller shall (i) use its commercially reasonable efforts to cause the Partnership to, and (ii) if applicable, vote all of its general partnership interests in the Partnership in a manner consistent with causing the Partnership to, operate the Business only in the ordinary course of business, consistent with past practice. Without limiting the generality of the foregoing, and, except as contemplated in this Agreement or as described in Section 6.1-B of the Seller Disclosure Schedule, prior to the Closing Date, without the prior written consent of Buyer (such consent not to be unreasonably withheld, delayed or conditioned), Seller shall (i) use its commercially reasonable efforts to cause the Partnership, and (ii) if applicable, vote all of its general partnership interests in the Partnership in a manner consistent with causing the Partnership, not to:

(a) (i) create, incur or assume any material amount of indebtedness for borrowed money, other than in the ordinary course of business consistent with past practice, including obligations in respect of capital leases but excluding purchase money mortgages granted in connection with the acquisition of property in the ordinary course of business, or (ii) assume, guarantee, endorse or otherwise become liable or responsible (whether directly, contingently or otherwise) for the obligations of any other Person except in the ordinary course of business consistent with past practice;

(b) make any material change in the operations of the Business;

(c) sell, lease (as lessor), transfer or otherwise dispose of, any of the material assets of the Business, other than in the ordinary course of business consistent

with past practice, or mortgage or pledge, or impose or suffer to be imposed any Encumbrance on, any of the material assets of the Business;

(d) except as may be contemplated by the capital expenditure budget of the Partnership previously delivered or made available to Buyer, make any capital expenditures in excess of $250,000 individually or $500,000 in the aggregate;

(e) enter into or materially amend any Material Contracts or Permits or waive or release any material right thereunder other than in the ordinary course of business consistent with past practice;

(f) make any change in any material respect to any of the accounting principles, methods, policies or practices used by the Partnership, except for any change required by reason of a concurrent change in GAAP;

(g) make or change any material Tax elections or Tax accounting methods of the Partnership, except as required by applicable law, prepare or file any Tax Return (or amendment thereof) unless prepared in a manner consistent with past practice or settle or compromise any material Tax claim or liability;

(h) amend or change its organizational documents;

(i) (i) transfer, issue, sell, pledge, encumber, dispose or deliver any general partnership interests or any securities convertible or exchangeable into general partnership interests; (ii) grant any rights to purchase or otherwise acquire any general partnership interests or any securities convertible or exchangeable into general partnership interests; or (iii) amend in any material respect any of the terms of any such general partnership interests or any securities convertible or exchangeable into general partnership interests outstanding as of the date hereof;

(j) (i) repurchase or otherwise acquire any general partnership interest of the Partnership; or (ii) adopt a plan of complete or partial liquidation or resolutions providing for or authorizing a liquidation, dissolution, consolidation, restructuring, recapitalization, or other reorganization of the Partnership;

(k) acquire (by merger, consolidation, or acquisition of stock or assets or otherwise) any corporation, partnership, or other business organization or division thereof;

(l) settle or compromise any pending or threatened legal proceeding or any claim or claims for, or that would result in Losses by the Partnership following the Closing of, an amount that could, individually or in the aggregate, reasonably be expected to be greater than $500,000**;**

(m) (i) hire any employees prior to Closing; or (ii) establish, adopt or enter into any collective bargaining agreement or benefits plan, except as required under applicable law; or

(n) agree or otherwise commit to enter into any Contract, whether written or oral, with respect to any of the transactions set forth in the foregoing paragraphs (a) through (m).

6.2 Access to Information. (a) Between the date of this Agreement and the Closing Date, Seller shall (solely with respect to the Business), during ordinary business hours and upon reasonable notice, (i) give Buyer and its Representatives reasonable access to its personnel and all books, records, plants, offices and other facilities and properties constituting and solely related to the Business and the Partnership in Seller's possession and control which Buyer is permitted access by law as Buyer may reasonably request, (ii) permit Buyer to make such reasonable inspections thereof as Buyer may reasonably request; (iii) cause its officers and advisors to as promptly as reasonably practicable furnish Buyer with such financial and operating data and other information with respect to the Business in Seller's possession and control as Buyer may from time to time reasonably request; and (iv) cause its officers and advisors to as promptly as reasonably practicable furnish Buyer a copy of each report, schedule or other document filed or received by them with the FERC with respect to the Business in Seller's possession and control which Buyer is permitted access by law as Buyer may reasonably request; provided, however, that (A) any such investigation shall be conducted in such a manner as not to interfere unreasonably with the operation of the Business or the businesses of Seller or its Affiliates, (B) neither Seller nor the Partnership shall be required to take any action which would constitute a waiver of the attorney-client privilege and (C) neither Seller nor the Partnership shall be required to supply Buyer with any information which is subject to a reasonable legal obligation not to be supplied; provided, further, that in the case of (B) above, Seller will give reasonable access to such information to Buyer upon the execution by Buyer and Seller of a joint defense agreement, the terms of which shall be mutually agreed upon by such parties. Notwithstanding anything in this Section 6.2 to the contrary, (i) Seller and the Partnership shall not be obligated to furnish or provide such access to medical records to the extent prohibited by applicable law and (ii) Buyer shall not have the right to perform or conduct any environmental sampling or testing at, in, on or underneath any of the property used in the operation of the Business.

(b) All information furnished to or obtained by Buyer and its Representatives pursuant to this Section 6.2 shall be treated as confidential information and shall not be disclosed to any Person without the prior written consent of Seller.

(c) For a period of seven (7) years after the Closing Date, Seller and its Representatives shall have reasonable access to, including the right to photocopy, scan, fax or otherwise reproduce, all of the books and records of the Business in Buyer's possession and control to the extent that such access may reasonably be required by Seller in connection with matters relating to or affected by the operation of the Business prior to the Closing Date; provided, however, that any such actions shall be conducted in such a manner as not to interfere unreasonably with the operation of the Business. Such access shall be afforded by Buyer upon receipt of reasonable advance notice and during normal business hours. Seller shall be solely responsible for any costs or expenses incurred by them pursuant to this Section 6.2(c). If Buyer shall desire to dispose of any

such books and records prior to the expiration of such seven-year period, Buyer shall, prior to such disposition, give Seller a reasonable opportunity, at Seller's expense, to segregate and remove such books and records as Seller may select.

6.3 Expenses. Except to the extent otherwise specifically provided herein, whether or not the transactions contemplated hereby are consummated, all costs and expenses incurred in connection with this Agreement and the transactions contemplated hereby shall be borne by the party incurring such costs and expenses.

6.4 Further Assurances. Subject to the terms and conditions of this Agreement, each of the parties hereto shall use all commercially reasonable efforts to take, or cause to be taken, all action, and to do, or cause to be done, all things necessary, proper or advisable under applicable laws and regulations to consummate and make effective the sale of the Interest pursuant to this Agreement. From time to time after the date hereof, without further consideration, Seller shall, at Seller's expense, execute and deliver such documents to Buyer as Buyer may reasonably request in order more effectively to vest in Buyer ownership of the Interest. From time to time after the date hereof, Buyer shall, at Buyer's own expense, execute and deliver such documents to Seller as Seller may reasonably request in order to more effectively consummate the sale of the Interest pursuant to this Agreement. Notwithstanding anything to the contrary in this Section 6.4, no party shall be required to (a) expend funds or assume liabilities beyond those that are reasonable in nature and amount in the context of the transactions contemplated hereunder, (b) divest any of its assets, including its businesses, divisions or properties or (c) agree to restrictions on its businesses, operations or conduct other than those that have been expressly agreed to in this Agreement.

6.5 Public Statements. After the execution of this Agreement, the parties shall consult with each other prior to issuing any public announcement, statement or other disclosure with respect to this Agreement, or the transactions contemplated hereby, and neither party shall issue any such public announcement, statement or other disclosure without having first received the consent of the other party (such consent not to be unreasonably withheld or delayed), except as may be required by law.

6.6 Consents and Approvals. (a) Seller and Buyer shall cooperate with each other and (i) promptly prepare and file all necessary documentation, (ii) effect all necessary applications, notices, petitions and filings, and execute all agreements and documents, and (iii) use all commercially reasonable efforts to obtain all necessary consents, approvals and authorizations of all other Persons, in the case of each of the foregoing clauses (i), (ii), and (iii), necessary or advisable to consummate the transactions contemplated by this Agreement (including the Seller Required Regulatory Approvals and the Buyer Required Regulatory Approvals) or required by the terms of any deed of trust, franchise, Permit, concession, Contract or other instrument to which Seller, the Partnership, or Buyer is a party or by which any of them is bound. Seller shall have the right to review and approve in advance all characterizations of the information relating to the Business, and each of Seller and Buyer shall have the right to review and approve in advance all characterizations of the information relating to the transactions contemplated by this Agreement, which appear in any filing made in connection with the transactions

contemplated hereby. The parties agree that they shall consult with each other with respect to the transferring to Buyer or the obtaining by Buyer of all such necessary Environmental Permits, Permits, consents, approvals and authorizations of all third parties and Governmental Authorities. Seller and Buyer shall designate separate counsel with respect to all applications, notices, petitions and filings (joint or otherwise) relating to this Agreement and the transactions contemplated hereby on behalf of Seller, on the one hand, and Buyer, on the other hand, with all Governmental Authorities.

(b) The parties hereto shall consult with each other prior to proposing or entering into any stipulation or agreement with any Governmental Authority or any third party in connection with any federal, state or local governmental consents and approvals legally required for the consummation of the transactions contemplated hereby and shall not propose or enter into any such stipulation or agreement without the other party's prior written consent, which consent shall not be unreasonably withheld.

(c) Notwithstanding anything to contrary in this Section 6.4, no party shall be required to (i) expend funds or assume liabilities beyond those that are reasonable in nature and amount in the context of the transactions contemplated hereunder, (ii) divest any of its assets, including its businesses, divisions or properties or (iii) agree to restrictions on its businesses, operations or conduct other than those that have been expressly agreed to in this Agreement.

6.7 Tax Matters. (a) Notwithstanding any other provision of this Agreement, all Transfer Taxes incurred in connection with this Agreement and the transactions contemplated hereby shall be borne by Buyer, and Buyer shall, at its own expense, file, to the extent required by law, all necessary Tax Returns and other documentation with respect to all such Transfer Taxes, and, if required by applicable law, Seller shall join in the execution of any such Tax Returns or other documentation.

(b) Each of Buyer and Seller shall provide the other with such assistance as may reasonably be requested by the other party in connection with the preparation of any Tax Return, any audit or other examination by any Taxing Authority, or any judicial or administrative proceedings relating to liability for Taxes of the Partnership or with respect to the assets of the Partnership, and each shall retain and provide the requesting party with any records or information which may be relevant to such return, audit or examination, proceedings or determination. Any information obtained pursuant to this Section 6.7 or pursuant to any other Section hereof providing for the sharing of information or review of any Tax Return or other schedule relating to Taxes shall be kept confidential by the parties hereto.

6.8 Supplements to Schedules. On one or more occasions prior to the Closing Date, Seller may update, supplement or amend the Seller Disclosure Schedule with additional information to reflect events, facts, circumstances or occurrences arising (and, in the case of representation or warranties qualified by Seller's Knowledge, Seller's Knowledge obtained) after the date of this Agreement. Any such update, supplement or amendment shall be given effect and taken into account for purposes of this Agreement (including Article IX); provided, however, that any such update, supplement or

amendment shall be disregarded and not taken into account for purposes of determining whether the conditions set forth in Section 7.2(b) or Section 7.2(d) have been satisfied.

6.9 No Implied Representations. Buyer hereby acknowledges and agrees that none of Seller, the Partnership, their Affiliates or any other Person has made or is making any representation or warranty whatsoever, express or implied, at law or in equity, except those representations and warranties of Seller explicitly set forth in Article IV of this Agreement. Without limiting the generality of the foregoing, except as explicitly set forth in Article IV of this Agreement, none of Seller, the Partnership, their Affiliates or any other Person has made or is making any representation, express or implied, with respect to Seller, the Partnership, their respective businesses or any of their assets, liabilities or operations, their past, current or future financial condition, profitability or performance, the value of any of their assets or any assets of the Business, the merchantability, suitability or fitness for a particular purpose or quality with respect to any of their assets or any assets of the Business or the condition or workmanship thereof or the absence of any defects therein (whether latent or patent), and any such other representations or warranties are hereby expressly disclaimed.

6.10 Financial Statements. During the period from the date hereof to the Closing, upon the reasonable request of Buyer from time to time, Seller shall as promptly as reasonably practicable provide Buyer with a copy of any financial statements and operating or management reports prepared by the Partnership in the ordinary course of business consistent with past practice that are in Seller's possession and control.

ARTICLE VII
CLOSING CONDITIONS

7.1 Conditions to Each Party's Obligations to Effect the Transactions Contemplated Hereby. The respective obligations of each party to effect the transactions contemplated hereby shall be subject to the fulfillment or waiver (other than the conditions set forth in subsections (a) and (b) of this Section 7.1) at or prior to the Closing Date of the following conditions:

(a) No preliminary or permanent injunction or other order or decree by any federal or state court which prevents the consummation of the transactions contemplated hereby shall have been issued and remain in effect (each party agreeing to use its commercially reasonable efforts to have any such injunction, order or decree lifted) and no statute, rule or regulation shall have been enacted by any state or federal government or Governmental Authority in the United States which prohibits the consummation of the transactions contemplated hereby.

7.2 Conditions to Obligations of Buyer. The obligation of Buyer to effect the transactions contemplated by this Agreement shall be subject to the fulfillment at or prior to the Closing Date of the following additional conditions (any or all of which may be waived by Buyer in whole or in part in its sole discretion):

(a) Seller shall have performed and complied in all material respects with the covenants and agreements contained in this Agreement required to be performed and complied with by Seller on or prior to the Closing Date;

(b) The representations and warranties of Seller set forth in Article IV of this Agreement (disregarding any Material Adverse Effect or materiality qualifiers therein) shall be true and correct on and as of the Closing Date with the same force and effect as if made on and as of the Closing Date (except to the extent such representations and warranties shall have been expressly made as of an earlier date, in which case such representations and warranties shall have been true and correct only as of such earlier date), except for such failures to be true and correct which would not have or be reasonably expected to have, individually or in the aggregate, a Material Adverse Effect;

(c) Buyer shall have received a certificate from the authorized officer of Seller, dated the Closing Date, to the effect that to the best of such officer's knowledge, the conditions set forth in Sections 7.2(a) and 7.2(b) have been satisfied;

(d) Since the date of this Agreement, there has not been any event, change, occurrence or circumstances that has had, or would reasonably be expected to have, a Material Adverse Effect; and

(e) Seller shall have made all deliveries required under Section 3.2.

7.3 Conditions to Obligations of Seller. The obligation of Seller to effect the transactions contemplated by this Agreement shall be subject to the fulfillment at or prior to the Closing Date of the following additional conditions (any or all of which may be waived by Seller in whole or in part in its sole discretion):

(a) Buyer shall have performed in all material respects its covenants and agreements contained in this Agreement required to be performed and complied with by Buyer on or prior to the Closing Date;

(b) The representations and warranties of Buyer set forth in Article V of this Agreement (disregarding any materiality qualifiers therein) shall be true and correct on and as of the Closing Date with the same force and effect as if made on and as of the Closing Date (except to the extent such representations and warranties shall have been expressly made as of an earlier date, in which case such representations and warranties shall have been true and correct only as of such earlier date), except for such failures to be true and correct which would not or be reasonably expected to, individually or in the aggregate, materially impair Buyer's ability to perform its obligations under this Agreement or consummate the transactions contemplated hereby or thereby;

(c) Seller shall have received a certificate from an authorized officer of Buyer, dated the Closing Date, to the effect that, to the best of such officer's knowledge, the conditions set forth in Sections 7.3(a) and 7.3(b) have been satisfied; and

(d) Buyer shall have made all deliveries required under Section 3.3.

ARTICLE VIII
TERMINATION

8.1 Termination. (a) This Agreement may be terminated at any time prior to the Closing Date, by mutual written consent of Buyer and Seller.

(b) This Agreement may be terminated by Seller or Buyer if the transactions contemplated hereby shall not have been consummated on or before six (6) months from the date of this Agreement (the "**Termination Date**"); provided, however, that the right to terminate this Agreement under this Section 8.1(b) shall not be available to a party if its failure to fulfill any obligation under this Agreement has been the direct cause of, or directly resulted in, the failure of the Closing Date to occur on or before such date.

(c) This Agreement may be terminated by either Seller or Buyer if (i) any Governmental Authority, the consent of which is a condition to the obligations of Seller and Buyer to consummate the transactions contemplated hereby, shall have determined not to grant its consent and all appeals of such determination shall have been taken and have been unsuccessful, or (ii) any court of competent jurisdiction in the United States or any state shall have issued an order, judgment or decree permanently restraining, enjoining or otherwise prohibiting the transactions contemplated hereby and such order, judgment or decree shall have become final and nonappealable.

(d) This Agreement may be terminated by Buyer, if there has been a material violation or breach by Seller of any agreement, representation or warranty contained in this Agreement which has not been cured within thirty (30) days or which has rendered the satisfaction of any condition to the obligations of Buyer impossible and such violation or breach has not been waived by Buyer.

(e) This Agreement may be terminated by Seller, if there has been a material violation or breach by Buyer of any agreement, representation or warranty contained in this Agreement which has not been cured within thirty (30) days (except with respect to the obligations by Buyer to pay the Closing Consideration pursuant to Section 2.2 after all conditions to Buyer's obligations hereunder have been satisfied or waived, whereby Seller may immediately terminate this Agreement) or which has rendered the satisfaction of any condition to the obligations of Seller impossible and such violation or breach has not been waived by Seller.

8.2 Procedure and Effect of Termination. In the event of termination of this Agreement by Buyer or Seller pursuant to Section 8.1, written notice thereof shall forthwith be given by the terminating party to the other party and this Agreement shall terminate and the transactions contemplated hereby shall be abandoned, without further action by any of the parties hereto. If this Agreement is terminated as provided herein:

(a) such termination shall be the sole remedy of the parties hereto with respect to breaches of any agreement, representation or warranty contained in this Agreement and none of the parties hereto nor any of their respective trustees, directors,

officers, members, general partners, or Affiliates, as the case may be, shall have any liability or further obligation to the other party or any of their respective trustees, directors, officers, members, general partners, or Affiliates, as the case may be, pursuant to this Agreement, except in each case as specifically provided in this Section 8.2 and in Sections 6.2(b) and 6.3 and except in each case such termination shall not relieve (i) any party of any liability for any willful and material breach of this Agreement or (ii) Buyer of any liability for any breach of Section 5.4; and

(b) all filings, applications and other submissions made pursuant to this Agreement, to the extent practicable, shall be withdrawn from the agency or other person to which they were made.

ARTICLE IX
INDEMNIFICATION

9.1 Survival.

(a) The representations and warranties of the parties contained in Articles IV and V shall, subject to Section 9.1(c), survive the Closing until the date that is six (6) months after the Closing Date; provided, however, that any claim arising from a breach of Seller's representations or warranties set forth in Sections 4.2 (Authority), 4.4 (Capitalization) or 4.18 (Taxes) or Buyer's representations or warranties set forth in Section 5.2 (Authority) shall survive until the date that is ninety (90) days following the expiration of the applicable statute of limitations (including extensions thereof).

(b) All covenants and agreements contained herein that by their terms are to be performed in whole or in part, or which prohibit actions, subsequent to the Closing, shall survive the Closing in accordance with their terms. All other covenants and agreements contained herein shall not survive the Closing and shall thereupon terminate.

(c) The period of time a representation or warranty or covenant or agreement survives the Closing pursuant to this Section 9.1 shall be the "**Survival Period**" with respect to such representation or warranty or covenant or agreement. In the event notice of any claim for indemnification under this Article IX shall have been given within the applicable Survival Period and such claim has not been finally resolved by the expiration of such Survival Period, the representations or warranties or covenants or agreements that are the subject of such claim shall survive until such claim is finally resolved.

9.2 Indemnification Obligations of Seller.

(a) From and after the Closing, subject to the terms of this Article IX, Seller shall indemnify and hold harmless Buyer and its Affiliates (other than the Partnership) and their respective directors, officers, employees, stockholders, partners, members, agents, attorneys, representatives, successors and assigns (collectively, the "**Buyer Indemnified Parties**"), from and against any losses, damages, liabilities, costs and expenses (including reasonable costs of investigation and reasonable attorneys' fees),

interest, penalties, judgments, settlements, claims, obligations, deficiencies, demands, damages, fines, claims, suits, actions, causes of action, assessments, awards, whether or not involving a third party claim (collectively, "**Losses**") incurred by any Buyer Indemnified Party by reason of (i) any breach of any of the representations or warranties (in each case, when made) of Seller in Article IV and (ii) any breach of any of the covenants or agreements of Seller in this Agreement that by their terms are to be performed in whole or in part, or which prohibit actions, subsequent to the Closing Date.

(b) Except with respect to Losses incurred by any Buyer Indemnified Party as a result of a breach of Seller's representations or warranties set forth in Section 4.19 (Taxes), the obligation of Seller to indemnify any Buyer Indemnified Party for Losses is subject to the following limitations: (i) no Buyer Indemnified Party shall be entitled to make a claim against Seller for indemnification under Section 9.2(a)(i) ("**Buyer Claim**") unless and until the aggregate amount of Losses incurred by such Buyer Indemnified Party with respect to an event or occurrence and all other events or occurrences arising from the same circumstances **exceeds** $15,000 (a "**Base Claim**"); (ii) Seller shall not be required to provide indemnification to such Buyer Indemnified Party pursuant to Section 9.2(a)(i) unless the aggregate amount of Losses incurred by all the Buyer Indemnified Parties in respect of Buyer Claims constituting Base Claims exceeds 2.5% of the Closing Consideration (the "**Basket**"), and then the Buyer Indemnified Parties shall be entitled to indemnification for only the amount in excess of the Basket; and (iii) in no event shall the aggregate amount of Losses for which Seller is obligated to indemnify the Buyer Indemnified Parties pursuant to Section 9.2(a)(i) exceed 10% of the Closing Consideration (the "**Ceiling**").

9.3 Indemnification Obligations of Buyer.

(a) From and after the Closing, subject to the terms of this Article IX, Buyer shall indemnify and hold harmless Seller and its Affiliates (other than the Partnership) and their respective directors, officers, employees, stockholders, partners, members, agents, attorneys, representatives, successors and assigns (collectively, the "**Seller Indemnified Parties**") from and against Losses incurred by any Seller Indemnified Party by reason of (i) any breach of any of the representations or warranties (in each case, when made) of Buyer in Article V and (ii) any breach in any material respect of any of the covenants or agreements of Buyer in this Agreement that by their terms are to be performed in whole or in part, or which prohibit actions, subsequent to the Closing Date.

(b) The obligation of Buyer to indemnify any Seller Indemnified Party for Losses is subject to the following limitations: (i) no Seller Indemnified Parties shall be entitled to make a claim against Buyer for indemnification under Section 9.3(a)(i) ("**Seller Claim**") unless and until the aggregate amount of Losses incurred by the Seller Indemnified Parties with respect to an event or occurrence and all other events or occurrences caused by the same circumstances constitutes a Base Claim; (ii) Buyer shall not be required to provide indemnification to any Seller Indemnified Party pursuant to Section 9.3(a)(i) unless the aggregate amount of Losses incurred by all the Seller Indemnified Parties in respect of Seller Claims constituting Base Claims exceeds the

Basket, and then the Seller Indemnified Parties shall be entitled to indemnification for only the amount in excess of the Basket; and (iii) in no event shall the aggregate amount of Losses for which Buyer is obligated to indemnify the Seller Indemnified Parties pursuant to Section 9.3(a)(i) of this Agreement exceed the Ceiling.

9.4 Indemnification Procedures and Limitations.

(a) In the event that any action, suit, claim or proceeding is commenced by a third party involving a claim for which a party required to provide indemnification hereunder (an "**Indemnifying Party**") may be liable to a party entitled to indemnification (an "**Indemnified Party**") hereunder (a "**Third Party Claim**"), the Indemnified Party shall promptly notify the Indemnifying Party in writing of such Third Party Claim indicating the nature of such claim and the basis therefore (the "**Claim Notice**"); provided, however, that no delay on the part of the Indemnified Party in giving any such Claim Notice shall relieve the Indemnifying Party of any indemnification obligation hereunder except to the extent that the Indemnifying Party is adversely prejudiced by such delay. Thereafter, the Indemnified Party shall deliver to the Indemnifying Party, promptly following the Indemnified Party's receipt thereof, copies of all notices and documents (including court papers) received by the Indemnified Party relating to the Third-Party Claim. Subject to the provisions related to the settlement of Third-Party Claims set forth in Section 9.4(b), the Indemnifying Party will have the right to defend against, negotiate, settle or otherwise deal with any Third-Party Claim and to select counsel of its choice. If the Indemnifying Party does not, within 30 days from its receipt of the Claim Notice (the "**Notice Period**"), elect to undertake to defend against, negotiate, settle or otherwise deal with any Third Party Claim, the Indemnified Party may, subject to the provisions related to the settlement of Third-Party Claims set forth in Section 9.4(b), defend against, negotiate, settle or otherwise deal with such Third Party Claim. If the Indemnifying Party undertakes to defend against such Third Party Claim, (i) the Indemnifying Party shall not be liable to the Indemnified Party for any legal fees or expenses incurred by the Indemnified Party in connection with such Third Party Claim and (ii) the Indemnified Party may participate and retain counsel, at its own cost and expense, in the defense of such Third Party Claim (it being understood and agreed that the

Indemnifying Party shall control such defense); provided, however, the Indemnified Party will be entitled to participate in any such defense with separate counsel the reasonable fees and expenses of which the Indemnifying Party shall bear if, but only if, (A) so requested by the Indemnifying Party to participate or (B) a conflict of interest exists between the Indemnified Party and the Indemnifying Party that would make it inappropriate in the reasonable judgment of such Indemnified Party (upon and in conformity with the advice of counsel) for the same counsel to represent both the Indemnified Party and the Indemnifying Party; provided, further, that the Indemnifying Party will not be required to pay the reasonable fees and expenses of more than one (1) such counsel for all Indemnified Parties in connection with any Third-Party Claim.

(b) If the Indemnifying Party undertakes to defend against such Third Party Claim, the other party shall (and shall cause the applicable Indemnified Parties to) (i) fully cooperate with the Indemnifying Party and its counsel in the investigation, defense and settlement of such Third Party Claim, including providing all information

and documents available to the Indemnified Party which relate to such Third Party Claim and (ii) consent and agree to any settlement, compromise or discharge of a Third-Party Claim that the Indemnifying Party may recommend and that (A) does not require any payment or admission of liability by any Indemnified Party, (B) releases the Indemnified Party in connection with such Third-Party Claim and (C) does not otherwise have a material and adverse effect on the Business as determined by the Indemnified Party in its reasonable discretion. If the Indemnifying Party elects not to undertake within the Notice Period to defend against a Third-Party Claim, then the Indemnified Party shall not admit any liability with respect to, or settle, compromise or discharge, such Third-Party Claim without the Indemnifying Party's prior written consent (which shall not be unreasonably withheld or delayed).

(c) In calculating amounts payable to an Indemnified Party, the amount of any indemnified Losses shall be determined without duplication of any other Loss for which an indemnification claim has been made or could be made under any other representation, warranty, covenant, or agreement and shall be computed net of (i) payments recovered by the Indemnified Party under any insurance policy with respect to such Losses (it being understood and agreed by the parties that Seller (in the case of Seller Indemnified Parties) and Buyer (in the case of Buyer Indemnified Parties) shall use their commercially reasonable efforts to effect any such recovery), (ii) any prior or subsequent recovery by the Indemnified Party from any Person with respect to such Losses and (iii) any Tax benefit receivable by the Indemnified Party with respect to such Losses.

(d) Notwithstanding any other provision of this Agreement, in no event shall any Indemnified Party be entitled to indemnification pursuant to this Article IX to the extent any Losses were attributable to such Indemnified Party's own gross negligence or willful misconduct.

(e) To the extent that Seller makes any payment pursuant to this Article IX in respect of Losses for which Buyer or any of its Affiliates have a right to recover against a third party (including an insurance company), Seller shall be subrogated to the right of Buyer or any of its Affiliates to seek and obtain recovery from such third party; provided, however, that if Seller shall be prohibited from such subrogation, Buyer shall use its commercially reasonable efforts to seek recovery from such third party on Seller's behalf and shall pay any such recovery to Seller.

(f) Notwithstanding any other provision of this Agreement, in no event shall Seller or Buyer be liable for (i) punitive damages or any special, incidental, indirect or consequential damages of any kind or nature, regardless of the form of action through which such damages are sought or (ii) lost profits or diminution in value resulting from a breach or an alleged breach of any representation, warranty, covenant or other agreement set forth in this Agreement or otherwise in connection with the transactions contemplated hereby, even if under applicable Law, such lost profits or diminution in value would not be considered consequential or special damages.

(g) Except as otherwise provided by applicable law, Buyer and Seller agree to treat any indemnity payment made pursuant to this Article IX as an adjustment to the Purchase Price paid to Seller for all income Tax purposes.

(h) The remedies provided in this Article IX shall be the sole and exclusive remedies of the parties, from and after the Closing Date, with respect to this Agreement and the transactions contemplated hereby.

ARTICLE X
MISCELLANEOUS PROVISIONS

10.1 Amendment and Modification. Subject to applicable law, this Agreement may be amended, modified or supplemented only by written agreement of Seller and Buyer.

10.2 Waiver of Compliance; Consents. Except as otherwise provided in this Agreement, any failure of any of the parties to comply with any obligation, covenant, agreement or condition herein may be waived by the party entitled to the benefits thereof only by a written instrument signed by the party granting such waiver, but such waiver or failure to insist upon strict compliance with such obligation, covenant, agreement or condition shall not operate as a waiver of, or estoppel with respect to, any subsequent or other failure.

10.3 Notices. All notices and other communications hereunder shall be in writing and shall be deemed given if delivered personally or by facsimile transmission, or mailed by a nationally recognized overnight courier or registered or certified mail (return receipt requested), postage prepaid, to the parties at the following addresses (or at such other address for a party as shall be specified by like notice, provided that notices of a change of address shall be effective only upon receipt thereof):

(a) If to Seller, to:

TCPL Tuscarora Ltd.
450 1st Street S.W.
Calgary, Alberta, Canada T2P 5H1
Attention: General Counsel, TransCanada Corporation
Telecopy: (403) 920-2410

(b) if to Buyer, to:

TC PipeLines GP, Inc.
450 1st Street S.W.
Calgary, Alberta, Canada T2P 5H1
Attention: Secretary
Telecopy: (403) 920-2460

10.4 Assignment. This Agreement and all of the provisions hereof shall be binding upon and inure to the benefit of the parties hereto and their respective

successors and permitted assigns, but neither this Agreement nor any of the rights, interests or obligations hereunder shall be assigned by any party hereto, including by operation of law, without the prior written consent of the other party (which may be withheld in its sole discretion); provided, that, without the consent of Seller, but with prior notice to Seller, Buyer may assign all or any portion of its rights and obligations under this Agreement to one or more Affiliates of Buyer (provided, however, that (a) each such assignee shall execute a supplementary agreement pursuant to which it agrees to be bound by the terms and conditions of this Agreement and (b) no assignment of rights or obligations pursuant to this Section 10.4 shall relieve the assigning party of its obligations hereunder).

10.5 Governing Law. This Agreement shall be governed by and construed in accordance with the laws of the State of New York (regardless of the laws that might otherwise govern under applicable New York principles of conflicts of law) as to all matters, including matters of validity, construction, effect, performance and remedies.

10.6 Facsimiles; Counterparts. This Agreement may be executed by facsimile signatures by any party and such signature shall be deemed binding for all purposes hereof, without delivery of an original signature being thereafter required. This Agreement may be executed in one or more counterparts, each of which, when executed, shall be deemed to be an original and all of which together shall constitute one and the same document.

10.7 Interpretation. The article and section headings contained in this Agreement are solely for the purpose of reference, are not part of the agreement of the parties and shall not in any way affect the meaning or interpretation of this Agreement. When a reference is made in this Agreement to an Article, Section, Exhibit or Schedule, such reference shall be to an Article, Section, Exhibit or Schedule of or to this Agreement unless otherwise indicated. References in this Agreement to “dollars” or “$” are to U.S. dollars. Whenever the words “include,” “includes” or “including” are used in this Agreement, they shall be deemed to be followed by the words “without limitation.” When a reference in this Agreement is made to a “party” or “parties,” such reference shall be to a party or parties to this Agreement unless otherwise indicated.

10.8 Entire Agreement. This Agreement constitutes the entire agreement and understanding of the parties with respect to the subject matter hereof and supersedes all prior agreements and understandings between the parties with respect to such subject matter.

10.9 Severability. Whenever possible, each provision or portion of any provision of this Agreement will be interpreted in such manner as to be effective and valid under applicable law but if any provision or portion of any provision of this Agreement is held to be invalid, illegal or unenforceable in any respect under any applicable law or rule in any jurisdiction, such invalidity, illegality or unenforceability will not affect any other provision or portion of any provision in such jurisdiction, and this Agreement will be reformed, construed and enforced in such jurisdiction as if such

invalid, illegal or unenforceable provision or portion of any provision had never been contained herein.

10.10 Third Party Beneficiaries. This Agreement shall be binding upon and inure solely to the benefit of the parties hereto and their respective successors and assigns. None of the provisions of this Agreement shall be for the benefit of or enforceable by any third party, including any creditor of any party or any of their Affiliates. No such third party shall obtain any right under any provision of this Agreement or shall by reasons of any such provision make any claim in respect of any liability (or otherwise) against either party hereto.

IN WITNESS WHEREOF, Seller and Buyer have caused this Agreement to be signed by their respective duly authorized officers as of the date first above written.

TCPL TUSCARORA LTD.

By: /s/ Ronald L. Cook

Name: Ronald L. Cook

Title: Vice-President, Taxation

By: /s/ Donald J. DeGrandis

Name: Donald J. DeGrandis

Title: Assistant Secretary

TC PIPELINES TUSCARORA LLC

By: /s/ Mark A.P. Zimmerman

Name: Mark A.P. Zimmerman

Title: President

By: /s/ Donald J. DeGrandis

Name: Donald J. DeGrandis

Title: Assistant Secretary

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Section 3: EX-3.1.1 (AMENDMENT TO THE AMENDED AND RESTATED AGREEMENT OF LIMITED PARTNERSHIP OF TC PIPELINES, LP)

Exhibit 3.1.1

AMENDMENT NO.1
TO THE AMENDED AND RESTATED AGREEMENT
OF LIMITED PARTNERSHIP OF TC PIPELINES, LP

DATED EFFECTIVE NOVEMBER 14, 2007

WHEREAS TC PipeLines, LP (the "Partnership") is a limited partnership initially consisting of TC PipeLines GP, Inc., a Delaware corporation, as General Partner (the "General Partner") and TransCan Northern Ltd., a Delaware Corporation, as the Organizational Limited Partner, both of whom entered into the Amended and Restated Agreement of Limited Partnership of TC Pipelines, LP dated May 28, 1999 ("Partnership Agreement");

WHEREAS, subsequent to the execution of the Partnership Agreement, the Partnership offered common units in the Partnership to the public and now has approximately 34,856,086 common units issued and outstanding;

WHEREAS, the Partnership Agreement provides that the General Partner may adopt a form of certificate other than the form of Certificate currently specified in the Partnership Agreement, as it may wish to adopt in its discretion;

WHEREAS, the NASDAQ Stock Market adopted new rules that require listed companies or securities to be eligible for The Depository Trust Company's direct Registration System ("DRS") by January 1, 2008;

WHEREAS, DRS provides for electronic direct registration of eligible securities in an investor's name on the books of the transfer agent or issuer and allows partnership securities to be transferred between a transfer agent and broker;

WHEREAS, to comply with the rules of the NASDAQ Stock Market, the Partnership wishes to authorize a system of issuance, recordation and transfer of the Partnership's securities by electronic or other means not involving any issuance of certificates;

WHEREAS, Section 13.1(d)(ii)(B) of the Partnership Agreement provides that the General Partner, without the approval of any other partner, may amend any provision of the Partnership Agreement to make a change that, in the discretion of the General Partner, is necessary or advisable to comply with any rule, regulation, guideline or requirement of any National Securities Exchange; and

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WHEREAS, the General Partner desires to make clear that such "other form of certificate" may include uncertificated securities, by amending the definition of "Certificate" in the Partnership Agreement.

NOW THEREFORE, the General Partner, on behalf of the Partnership, hereby amends the Partnership Agreement as follows:

1. Definitions. Unless otherwise defined herein, capitalized terms shall have the meanings set forth in the Partnership Agreement.

2. Amendment of Partnership Agreement. The Partnership Agreement shall be amended as follows:

(a) Section 1.1 is amended by deleting the definition of "Certificate" it in its entirety and inserting in its place the following:

""Certificate" means a certificate or an uncertificated electronic registration system (i) substantially in the form of Exhibit A to this Agreement, (ii) issued in global form in accordance with the rules and regulations of the Depository, (iii) in such other form as may be adopted by the General Partner in its discretion, evidencing ownership of one or more Common Units, or in such form as may be adopted by the General Partner in its discretion, evidencing ownership of one or more other Partnership Securities."

(b) Section 4.1 is amended by adding the following to the end of the current paragraph:

"Notwithstanding anything in this Section 4.1 or any other provision of this Agreement, at the General Partner's discretion, the Partnership's securities may be issued, recorded and transferred by electronic or other means not involving the issuance of physical Certificates. The provisions of this Agreement shall be interpreted as reasonably required to implement such a system. For example, no signature shall be required with respect to an uncertificated electronic registration system."

3. Except as amended hereby, the terms and provisions of the Partnership Agreement shall remain in full force and effect.

IN WITNESS WHEREOF, the General Partner has executed this Amendment effective as of the 14th day of November, 2007.

TC PIPELINES GP, INC.,
as General Partner of
TC PipeLines, LP

By: /s/ Donald J. DeGrandis
Name: Donald J. DeGrandis
Title: Secretary

By: /s/ Mark A.P. Zimmerman
Name: Mark A.P. Zimmerman
Title: President

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Section 4: EX-10.20 (TRANSPORTATION SERVICE AGREEMENT CONTRACT IDENTIFICATION FT4760)

Exhibit 10.20

Great Lakes
Gas Transmission Company

TRANSPORTATION SERVICE AGREEMENT Contract Identification FT4760

This Transportation Service Agreement (Agreement) is entered into by Great Lakes Gas Transmission Limited Partnership (Transporter) and TRANSCANADA PIPELINES LIMITED (Shipper).

WHEREAS, Shipper has requested Transporter to transport Gas on its behalf and Transporter represents that it is willing to transport Gas under the terms and conditions of this Agreement.

NOW, THEREFORE, Transporter and Shipper agree that the terms below constitute the transportation service to be provided and the rights and obligations of Shipper and Transporter.

1. **EFFECTIVE DATE**: December 07, 2007

2. **CONTRACT IDENTIFICATION**: FT4760

3. **RATE SCHEDULE**: FT

4. **SHIPPER TYPE:** Other

5. **STATE/PROVINCE OF INCORPORATION**: Canada

6. **TERM**: November 01, 2005 to October 31, 2009

7. **EFFECT ON PREVIOUS CONTRACTS:**

   This Agreement supersedes, cancels and terminates, as of the effective date stated above, the following contract(s): Service Agreement dated November 30, 2006 with Contract Identification FT4760.

   Shipper's and Transporter's obligations to each other arising for periods prior to the effective date stated above, remain in effect and are not being terminated by any provision of this Agreement.

8. **MAXIMUM DAILY QUANTITY (Dth/Day)**: 25,000

   Please see Appendix A for further detail.

9. **RATES**:

   Unless Shipper and Transporter have agreed to a Discounted Rate, pursuant to Section 19.2 of the General Terms and Conditions, or to a Negotiated Rate, pursuant to Section 4.5 of the Rate Schedule named above, rates shall be Transporter's maximum rates and charges plus all applicable surcharges in effect from time to time under the applicable Rate Schedule (as stated above) on file with the Commission unless otherwise agreed to by the parties in writing. Provisions governing a Discounted Rate shall be set forth in this Paragraph 9. Provisions governing a Negotiated Rate shall be set forth on Appendix B hereto.

Contract ID: FT4760

10. **POINTS OF RECEIPT AND DELIVERY**:

    The primary receipt and delivery points are set forth on Appendix A.

11. **RELEASED CAPACITY**:

N/A

12. **INCORPORATION OF TARIFF INTO AGREEMENT**:

This Agreement shall incorporate and in all respects be subject to the “General Terms and Conditions” and the applicable Rate Schedule (as stated above) set forth in Transporter’s FERC Gas Tariff, Second Revised Volume No. 1, as may be revised from time to time. Transporter may file and seek Commission approval under Section 4 of the Natural Gas Act (NGA) at any time and from time to time to change any rates, charges or provisions set forth in the applicable Rate Schedule (as stated above) and the “General Terms and Conditions” in Transporter’s FERC Gas Tariff, Second Revised Volume No. 1, and Transporter shall have the right to place such changes in effect in accordance with the NGA, and this Agreement shall be deemed to include such changes and any such changes which become effective by operation of law and Commission Order, without prejudice to Shipper’s right to protest the same.

13. **MISCELLANEOUS**:

No waiver by either party to this Agreement of any one or more defaults by the other in the performance of this Agreement shall operate or be construed as a waiver of any continuing or future default(s), whether of a like or a different character

Any controversy between the parties arising under this Agreement and not resolved by the parties shall be determined in accordance with the laws of the State of Michigan.

14. **OTHER PROVISIONS**:

It is agreed that no personal liability whatsoever shall attach to, be imposed on or otherwise be incurred by any Partner, agent, management official or employee of the Transporter or any director, officer or employee of any of the foregoing, for any obligation of the Transporter arising under this Agreement or for any claim based on such obligation and that the sole recourse of Shipper under this Agreement is limited to assets of the Transporter.

Upon termination of this Agreement, Shipper’s and Transporter’s obligations to each other arising under this Agreement, prior to the date of termination, remain in effect and are not being terminated by any provision of this Agreement.

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15. **NOTICES AND COMMUNICATIONS**:

All notices and communications with respect to this Agreement shall be in writing and sent to the addresses stated below or at any other such address(es) as may be designated in writing:

ADMINISTRATIVE MATTERS

Great Lakes Gas Transmission Limited Partnership
5250 Corporate Drive
Troy, MI 48098
Attn: Transportation Services

TRANSCANADA PIPELINES LIMITED
450 - 1st Street S.W.
Calgary, AB T2P 5H1
Canada
Attn: Steve Pohlod

PAYMENT BY ELECTRONIC TRANSFER

Great Lakes Gas Transmission Limited Partnership
JPMorgan Chase Bank, Detroit, MI
ABA No: 072000326
Account No: 07308-43

TRANSCANADA PIPELINES LIMITED
Attn: Angie Czenczek

AGREED TO BY:

GREAT LAKES CAS TRANSMISSION LIMITED PARTNERSHIP
By: Great Lakes Gas Transmission Company

Operator and Agent for Great Lakes Gas Transmission Limited Partnership

By: /s/ Martin Wilde
Martin Wilde
Title: Director, Marketing

TRANSCANADA PIPELINES LIMITED

By: /s/ Max Feldman
Max Feldman
Title: Senior Vice President, Canadian and Eastern US Pipelines

By: /s/ John Van der Put
John Van der Put
Title: Vice President, Market Development, Canadian and Eastern U.S. Pipelines

APPENDIX A Contract Identification
FT4760

Date: December 07, 2007
Supersedes Appendix Dated: November 30, 2006

Shipper: TRANSCANADA PIPELINES LIMITED

Maximum Daily Quantity (Dth/Day) per Location:

Begin Date	End Date	Point(s) of Primary Receipt	Point(s) of Primary Delivery	MDQ	(MAOP)
11/01/2005	10/31/2009	EMERSON		25,000	974
11/01/2005	10/31/2009		SAULT STE. MARIE TCPL	25,000	1142

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Section 5: EX-10.21 (TRANSPORTATION SERVICE AGREEMENT CONTRACT IDENTIFICATION FT8742)

Exhibit 10.21

Great Lakes
Gas Transmission Company

TRANSPORTATION SERVICE AGREEMENT
Contract Identification FT8742

This Transportation Service Agreement (Agreement) is entered into by Great Lakes Gas Transmission Limited Partnership (Transporter) and TRANSCANADA PIPELINES LIMITED (Shipper).

WHEREAS, Shipper has requested Transporter to transport Gas on its behalf and Transporter represents that it is willing to transport Gas under the terms and conditions of this Agreement.

NOW, THEREFORE, Transporter and Shipper agree that the terms below constitute the transportation service to be provided and the rights and obligations of Shipper and Transporter.

1. **EFFECTIVE DATE**: December 06, 2007

2. **CONTRACT IDENTIFICATION**: FT8742

3. **RATE SCHEDULE**: FT

4. **SHIPPER TYPE**: Other

5. **STATE/PROVINCE OF INCORPORATION**: Canada

6. **TERM**: November 01, 2008 to October 31, 2010

   Transporter and Shipper agree that Shipper may extend the primary terns of this Agreement by exercising a contractual Right of First Refusal, pursuant to the procedures set forth in section 16 of the General Terms and Conditions of Transporter's FERC Gas Tariff.

7. **EFFECT ON PREVIOUS CONTRACTS**:

   This Agreement supersedes, cancels and terminates, as of the effective date stated above, the following contract(s): N/A

8. **MAXIMUM DAILY QUANTITY (Dth/Day):** 470,000

Please see Appendix A for further detail.

9. **RATES**:

Unless Shipper and Transporter have agreed to a Discounted Rate, pursuant to Section 19.2 of the General Terms and Conditions, or to a Negotiated Rate, pursuant to Section 4.5 of the Rate Schedule named above, rates shall be Transporter's maximum rates and charges plus all applicable surcharges in effect from time to time under the applicable Rate Schedule (as stated above) on file with the Commission unless otherwise agreed to by the parties in writing. Provisions governing a Discounted Rate shall be set forth in this Paragraph 9. Provisions governing a Negotiated Rate shall be set forth on Appendix B hereto.

Shipper and Transporter agree that for service under this Agreement from the point(s) of receipt listed on Appendix A to the point(s) of delivery listed on Appendix A, the Reservation Fee to be charged shall be $9.733 per Dth.

10. **POINTS OF RECEIPT AND DELIVERY**:

The primary receipt and delivery points are set forth on Appendix A.

Contract ID: FT8742

11. **RELEASED CAPACITY**:

N/A

12. **INCORPORATION OF TARIFF INTO AGREEMENT**:

This Agreement shall incorporate and in all respects be subject to the "General Terms and Conditions" and the applicable Rate Schedule (as stated above) set forth in Transporter's FERC Gas Tariff, Second Revised Volume No. 1, as may be revised from time to time. Transporter may file and seek Commission approval under Section 4 of the Natural Gas Act (NGA) at any time and from time to time to change any rates, charges or provisions set forth in the applicable Rate Schedule (as stated above) and the "General Terms and Conditions" in Transporter's FERC Gas Tariff, Second Revised Volume No. 1, and Transporter shall have the right to place such changes in effect in accordance with the NGA, and this Agreement shall be deemed to include such changes and any such changes which become effective by operation of law and Commission Order, without prejudice to Shipper's right to protest the same.

13. **MISCELLANEOUS**:

No waiver by either party to this Agreement of any one or more defaults by the other in the performance of this Agreement shall operate or be construed as a waiver of any continuing or future default(s), whether of a like or a different character.

Any controversy between the parties arising render this Agreement and not resolved by the parties shall be determined in accordance with the laws of the State of Michigan.

14. **OTHER PROVISIONS**:

It is agreed that no personal liability whatsoever shall attach to, be imposed on or otherwise be incurred by any Partner, agent, management official or employee of the Transporter or any director, officer or employee of any of the foregoing, for any obligation of the Transporter arising under this Agreement or for any claim based on such obligation and that the sole recourse of Shipper under this Agreement is limited to assets of the Transporter.

Upon termination of this Agreement, Shipper's and Transporter's obligations to each other arising under this Agreement, prior to the date of termination, remain in effect and are not being terminated by any provision of this Agreement.

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15. **NOTICES AND COMMUNICATIONS**:

All notices and communications with respect to this Agreement shall be in writing and sent to the addresses stated below or at any other such address(es) as may be designated in writing:

ADMINISTRATIVE MATTERS

Great Lakes Gas Transmission Limited Partnership 5250 Corporate Drive Troy, MI 48098 Attn: Transportation Services	TRANSCANADA PIPELINES LIMITED 450 - 1st Street S.W. Calgary, AB T2P 5H1 Canada Attn: Steve Pohlod

PAYMENT BY ELECTRONIC TRANSFER
Great Lakes Gas Transmission Limited Partnership
JPMorgan Chase Bank, Detroit, MI
ABA No: 072000326
Account No: 07308-43

TRANSCANADA PIPELINES LIMITED
Attn: Andrea Morrical

AGREED TO BY:

GREAT LAKES CAS TRANSMISSION LIMITED PARTNERSHIP
By: Great Lakes Gas Transmission Company

Operator and Agent for Great Lakes Gas Transmission Limited Partnership

By: /s/ Martin Wilde
Martin Wilde
Title: Director, Marketing

TRANSCANADA PIPELINES LIMITED

By: /s/ Max Feldman
Max Feldman
Title: Senior Vice President, Canadian and Eastern US Pipelines

By: /s/ John Van der Put
John Van der Put
Title: Vice President, Market Development, Canadian and Eastern U.S. Pipelines

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APPENDIX A Contract Identification
FT8742

Date: December 06. 2007
Supersedes Appendices Dated: Not Applicable

Shipper: TRANSCANADA PIPELINES LIMITED

Maximum Daily Quantity (Dth/Day) per Location:

Begin Date	End Date	Point(s) of Primarv Receipt	Point(s) of Primarv Delivery	MDQ	(MAOP)
11/01/2008	10/31/2010	EMERSON		470,000	974
11/01/2008	10/31/2010		ST. CLAIR	470,000	974

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Section 6: EX-10.22 (THE TC PIPELINES GP, INC. SHARE UNIT PLAN FOR NON-EMPLOYEE DIRECTORS (2007), DATED OCTOBER 18, 2007)

Exhibit 10.22

THE TC PIPELINES GP, INC.
SHARE UNIT PLAN
FOR NON-EMPLOYEE DIRECTORS (2007)

Section 1 Purpose

The Share Unit Plan for Non-Employee Directors (2007) (the “Plan”) is intended to enhance the ability of TC PipeLines GP, Inc. (the “General Partner”) to attract and retain high quality individuals to serve as members of the Board and to promote a greater alignment of interests between non-employee members of the Board and unitholders of the Partnership. The Plan is effective as of October 18, 2007.

Section 2 Definitions

For the purposes of the Plan:

(a) “Affiliate” With respect to any person, any other person directly or indirectly controlling or controlled by or under direct or indirect common control with such specified person.

(b) “Agreement” means, with respect to a particular Eligible Director or Participant, the written agreement, as amended from time to time, entered into between the General Partner and such Eligible Director pursuant to Section 5 hereof, substantially in the form of agreement set out in Appendix A attached hereto;

(c) “Aggregate Purchase Price” has the meaning assigned thereto in Section 8.6 hereof;

(d) “Annual Retainer Fee” means the portion, expressed in dollars, of the annual retainer fee, annual committee chair retainer fee and the annual Board and committee attendance fee, which would, but for the Plan, be payable in cash by the General Partner to an Eligible Director for approximately one year of service as a member of the Board beginning on the date of the annual meeting of the General Partner at which the Board is elected and ending on the date immediately preceding the date of the following annual meeting of the General Partner, and for greater certainty, Annual Retainer Fee shall exclude amounts received by an Eligible Director as a reimbursement for expenses incurred in attending meetings and any other fee which may be payable by the General Partner to an Eligible Director;

(e) “Beneficiary” means an individual who, on the date of a Participant’s death, is the person who has been designated in accordance with Section 13.1 hereof and the laws applicable to the Plan, or where no such individual had been validly designated by the Participant, or where the designated individual does not survive the Participant, the Participant’s legal representative;

(f) “Board” means the Board of Directors of the General Partner;

(g) “Broker” has the meaning assigned thereto in Section 11.1 hereof;

(h) “Common Unit” means a common unit representing a limited partnership interest in TC PipeLines, LP (the “Partnership”), or any subsequent security to which the Common Units have been converted, exchanged or changed as reasonably determined by the Board;

(i) “Eligible Director” has the meaning assigned thereto in Section 4 hereof;

(j) “Entitlement Date” has the meaning assigned thereto in Section 8.1 hereof as it may be adjusted pursuant to Section 8.2 hereof;

(k) “Fair Market Value” of a Common Unit means, as of any date, the value of Common Unit determined as follows:

(A) If the Common Unit is listed on any established stock exchange or a national market system, including without limitation the Nasdaq National Market or The Nasdaq SmallCap Market of The Nasdaq Stock Market, its Fair Market Value shall be the closing sales price for such unit (or the closing bid, if no sales were reported) as quoted on such exchange or system for the market trading day on the time of determination (or if that is not a trading day, the most recently concluded trading day) as reported in *The Wall Street Journal* or such other source as the Board deems reliable;

(B) If the Common Unit is regularly quoted by a recognized securities dealer but selling prices are not reported, the Fair Market Value of a Common Unit shall be the mean between the high bid and low asked prices for the Common Unit for the market trading day on the time of determination (or if that is not a trading day, the most recently concluded trading day), as reported in *The Wall Street Journal* or such other source as the Board deems reliable; or

(C) In the absence of an established market for the Common Unit, the Fair Market Value thereof shall be determined in good faith by the Board.

(l) “Participant” means an Eligible Director who has been credited Share Units under the Plan;

(m) “Plan” means The TC PipeLines GP, Inc. Share Unit Plan for Non-Employee Directors (2007), as amended and restated from time to time;

(n) “Price per Common Unit” has the meaning assigned thereto in Section 8.6 hereof;

(o) "Payment Period" means any of the four quarters of any financial year of the General Partner, and which, on the effective date hereof, end on March 31, June 30, September 30 and December 31;

(p) "Quarterly Retainer Fee" means the amount, expressed in dollars, representing up to twenty-five (25%) of the Annual Retainer Fee which would, but for the Plan, be payable in cash on the last day of each Payment Period by the General Partner to an Eligible Director, or if, with respect to any Payment Period, an Eligible Director has served as a member of the Board for a number of days that is less than the full Payment Period, the amount, expressed in dollars, which is the product of: (i) the quotient determined by dividing: (A) the number of days in the particular Payment Period during which the Eligible Director served as a member of the Board, by (B) the aggregate number of days in the particular Payment Period; and (ii) the amount, expressed in dollars, of the quarterly retainer fee which would otherwise have been payable for such Payment Period had the Eligible Director served as a member of the Board for the full Payment Period;

(q) "Reference Date", with respect to any Payment Period, means the date which shall be used to determine, on a quarterly basis, the Fair Market Value of a Common Unit for purposes of determining the number of Share Units to be credited, for such Payment Period, to a Participant's account pursuant to Sections 6 and 7 hereof, which date shall be, unless otherwise determined by the Board, the last trading day of such Payment Period on which the Fair Market Value of a Common Unit may be determined;

(r) "Share Unit" means a unit credited by means of a bookkeeping entry on the books of the Partnership to a Participant's account in accordance with the terms and conditions of the Plan;

(s) "Subsidiary" means any corporation, partnership or joint venture a majority of whose shares or ownership interests normally entitled to vote in electing directors or selecting persons charged with managing the business and affairs of such entity is owned directly or indirectly by the Partnership, the General Partner or its parent, TransCanada Corporation; and

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(t) "Termination of Board Service" means the earliest date on which both of the following conditions are met: the Participant (1) has ceased to be an Eligible Director, and (2) is neither an employee of the Partnership, the General Partner or any of their Affiliates nor a member of the board of an Affiliate. With respect to a Participant who is a U.S. taxpayer, "Termination of Board Service" shall have the same meaning as a "separation from service" under section 409A of the Internal Revenue Code of 1986, as amended ("Section 409A").

Section 3 Administration of the Plan

Except where otherwise expressly provided herein, the Plan shall be administered by the Board and shall be subject to applicable corporate and securities law and policy requirements. All expenses of administration of the Plan shall be borne by the General Partner, including the purchase price of and any reasonable brokerage fees relating to the purchase of Common Units under the Plan.

Section 4 Eligibility

The Plan shall apply to all members of the Board who, on or at any time after the effective date of the Plan, and for so long as they continue to serve as members of the Board, are not otherwise employees of the General Partner, TransCanada Corporation or any of their Affiliates and have elected to participate in the Plan (each, an "Eligible Director").

Section 5 Execution of Agreement

Each Eligible Director shall, as soon as practicable after the effective date of the Plan or after the date on which such Eligible Director is elected or appointed for the first time, enter into an Agreement with the General Partner substantially in the form of the Agreement set out in Appendix A attached hereto. Such Agreement shall set out certain rights and obligations of the parties thereto with respect to the Share Units which shall, under the Plan, be credited to the account of a Participant and shall remain in full force and effect until all such Share Units shall have been redeemed.

Section 6 Deferral of Annual Retainer Fees and Grants of Additional Share Units

6.1 Each Eligible Director may choose to have credited to his or her account under the Plan, zero to 100 percent of his or her Annual Retainer Fee (or the portion thereof applicable to service of less than an entire term of approximately one year), in the form of Share Units in lieu of being paid such portion of his or her Annual Retainer Fee (or the portion thereof applicable to service of less than an entire term of approximately one year) in cash. In order to exercise this option, each such Eligible Director shall notify the Corporate Secretary of the General Partner before the commencement of the first calendar year for which such option is exercised. Thereafter, such Eligible Director shall remain a Participant in the Plan in respect of his or her Annual Retainer Fee until the election is withdrawn

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by him or her for a subsequent calendar year. The Corporate Secretary of the General Partner shall make inquiries on this matter to each Eligible Director in November of each year.

6.2 The number of Share Units (including fractional Share Units) to be credited on a quarterly basis to the account of an Eligible Director who has exercised his or her option under Section 6.1 hereof with respect to any particular Payment Period, shall be equal to the quotient determined by the following formula:

$$\frac{\text{Quarterly Retainer Fee}}{\text{Fair Market Value of Common Unit}}$$

where:

i. Quarterly Retainer Fee is all or a portion of the entire amount, expressed in dollars, of the Eligible Director's Quarterly Retainer Fee which would, but for the Plan, have been paid in cash with respect to such Payment Period; and

ii. Fair Market Value of Common Unit is the Fair Market Value of a Common Unit on the Reference Date for such Payment Period.

6.3 The Board may, at any time in satisfaction of fees other than Annual Retainer Fees that may be payable to Eligible Directors in their capacity as members of the Board or otherwise in respect of their service as members of the Board, grant additional Share Units to Eligible Directors who have elected to receive Share Units. In the case of Eligible Directors who have not served a full term of approximately one year, the Board may grant additional Share Units on a pro rata basis to such Eligible Directors. Share Units granted pursuant to this Section 6.3 shall be credited to the applicable Eligible Director's account under the Plan as at the date specified by the Board. Notwithstanding the foregoing, with respect to any Participant who is a U.S. taxpayer, the Board shall exercise this discretion within the time periods required under Section 409A.

6.4 A Participant who becomes an employee of the General Partner or TransCanada Corporation (other than in his or her capacity as a member of the Board) or a Subsidiary, shall no longer be eligible to have Share Units credited to his or her account under the Plan. However, Share Units already credited to such person's account shall remain governed by the Plan and the Agreement.

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Section 7 Distribution-like Amounts

A Participant's account shall, from time to time during the term of the Participant's Agreement, including the period following Termination of Board Service and until the Entitlement Date referred to in Section 8 hereof (even if the Entitlement Date a Participant elects pursuant to Section 8.1 falls between the record date for a distribution on the Common Units and the related distribution payment date), be credited, effective on each of the payment dates referred to below or on the Entitlement Date, as the case may be, with such number of additional Share Units equal to the quotient determined by the following formula:

$$\frac{\text{(Declared Distributions x Number of Share Units)}}{\text{Fair Market Value of Common Units}}$$

where:

i. Declared Distributions are one hundred percent (100%) of each distribution declared and paid by the Partnership on its Common Units on a per share basis (excluding stock dividends, but including distributions which may be paid in cash or in shares at the option of the unitholder);

ii. Number of Share Units are the number of Share Units recorded in the Participant's account on the record date for the payment of any such distribution; and

iii. Fair Market Value of Common Units is the Fair Market Value of a Common Unit on the payment date for such distribution, or if such payment date is not a trading date, on the preceding trading date, with fractions computed to four decimal places.

Section 8 Redemption of Share Units

8.1 Election of Entitlement Date

Participants shall redeem all of their Share Units on the respective Entitlement Dates elected in accordance with the following provisions:

(a) **Payouts to Participants who are not U.S. Taxpayers**. The value of the Share Units credited to the account under the Plan of each Participant who is not a U.S. taxpayer shall be redeemable by the Participant (or where the Participant has died, his Beneficiary) at the Participant's option (or after the Participant's death, at the option of his Beneficiary) following the Participant's Termination of Board Service by providing written notice of redemption to the Corporate Secretary of the General Partner specifying one of the dates specified in Section 8.1(c). The date so specified shall be the Participant's "Entitlement Date".

(b) **Payouts to Participants who are U.S. Taxpayers.** Participants who are U.S. taxpayers shall provide a written election to the Corporate Secretary of the General Partner prior to the end of each year that they are a Participant, fixing a single payout date following Termination of Board Service with respect to Share Units to be earned in the calendar year commencing immediately following the year in which such election is made. Any applicable payout date applicable to Share Units of a Participant under this Section 8.1 (b) shall be the Participant's "Entitlement Date" with respect to those Share Units. For clarity and as an example, a Participant might make an election in 2007 for Share Units that Participant will earn in 2008 and in 2008, may elect a different Entitlement Date for Share Units that Participant will earn in 2009.

(c) The permitted Entitlement Dates that a Participant elects pursuant to Sections 8.1(a) and (b) above, shall be the end of the first, second, third or fourth calendar quarter following the date of Termination of Board Service. If no payout date is elected with respect to any Share Units, then the payout dates in respect of such Share Units shall be the end of the first calendar quarter following the date of Termination of Board Service. In the case of Section 8.1(a) such notice shall be given within 60 days following the date of Termination of Board Service.

8.2 Adjustments to Entitlement Date

In the event any of the following provisions apply, the Entitlement Date elected by the Participant pursuant to Section 8.1 may be adjusted. In that case, the term 'Entitlement Date' shall mean the adjusted Entitlement Date, adjusted in accordance with this Section 8.2. Notwithstanding anything in this Section 8.2 to the contrary, with respect to Participants who are U.S. taxpayers, the adjusted Entitlement Date shall not be extended to a date beyond that permitted under Section 409A (and the regulations promulgated thereunder).

(a) Unavailable Data. In the event that the General Partner is unable, by a Participant's elected or adjusted Entitlement Date, to compute the final number of Share Units credited to such Participant's account by reason of the fact that any data required in order to compute the Fair Market Value of a Common Unit has not been made available to the General Partner, then the Entitlement Date shall be the trading day next following the date on which such data is made available to the General Partner.

(b) Undisclosed Material Information. Without limiting the generality of Section 14, subject to Section 8.5 and notwithstanding any other provision of the Plan, if, in the opinion of the Board, there is a material fact or a material change concerning the business and affairs of the Partnership, its Affiliates or Common Units (where "material fact" and "material change" have the meanings given under applicable securities legislation) that has not been generally disclosed to the public, on the Participant's Entitlement Date such Participant's Entitlement Date shall be postponed and no Common Units shall be purchased hereunder on behalf of such

Participant until such time as, in the opinion of the Board, such material fact or material change has been generally disclosed to the public or has ceased to exist.

8.3 Receipt of Common Units

If no election is made under Section 8.6, the General Partner shall arrange for a Participant, or a Participant's Beneficiary, as the case may be, to receive Common Units in satisfaction of, and in an number equal to, the number of Share Units recorded in the Participant's account on the Entitlement Date, subject to any adjustments pursuant to Section 17 hereof and reduced as necessary to reflect any applicable withholding taxes and other source deductions required by law to be withheld or deducted by the General Partner in connection with the redemption of the Participant's Share Units. Such Common Units shall be purchased in accordance with Sections 8.4 and Section 11 hereof.

8.4 Purchase of Common Units on Open Market

Prior to 11:00 a.m. on the Entitlement Date, the General Partner shall notify the Broker as to the number of Common Units to be purchased by the Broker on behalf of the Participant on the open market. As soon as practicable thereafter, the Broker shall purchase, on the open market, the number of Common Units which the General Partner has requested the Broker to purchase and shall notify the Participant and the General Partner of: (a) the aggregate purchase price ("Aggregate Purchase Price") of the Common Units, (b) the purchase price per Common Unit or, if the Common Units were purchased at different prices, the average purchase price (computed on a weighted average basis) per Common Unit ("Price per Common Unit"), (c) the amount of any related reasonable brokerage commission, and (d) the settlement date for the purchase of the Common Units, which settlement date shall not be later than the date specified in Section 8.5 hereof. On the settlement date, upon payment of the Aggregate Purchase Price and related reasonable brokerage commissions by the General Partner, the Broker shall deliver to the Participant or to the Participant's representative, the certificate representing the Common Units. Any entitlement to fractional Share Units shall be paid in cash based on the Price per Common Unit.

8.5 Delivery & Payment Date

Notwithstanding any other provision of the Plan, all Common Units to be purchased and delivered and all payments payable to or in respect of a Participant's Share Units hereunder, shall be delivered or paid in accordance with the Participant's election of an Entitlement Date pursuant to Section 8.1, but in no event later than December 31 of the calendar year following the year in which the Participant's Termination of Board Service occurs.

8.6 Election for Cash in Lieu of Common Units.

The Participant or the Participant's Beneficiary may elect, by providing written notice to the Corporate Secretary of the General Partner within 60 days of the Participant's Termination of Board Service, to receive the value of that Participant's Share Unit entitlement, as of the Entitlement Date, which is determined in accordance with Section 8.1(a) or (b) as applicable, in one lump sum cash payment (rather than receive Common Units) less any applicable withholdings, and the General Partner shall be fully discharged in making such cash payment. If the Participant or the Participant's Beneficiary provides the notice contemplated by this Section 8.6, the General Partner shall pay the value of the Share Units credited to the Participant's account under the Plan, computed as of the Entitlement Date. The lump sum cash payment, for the purpose of this Section 8.6, will be equivalent to the product determined by the following formula:

Share Units X Fair Market Value of a Common Unit

where:

Share Units means the number of Share Units standing to the credit of the Participant on the Entitlement Date; and

Fair Market Value of a Common Unit has the meaning given to it in Section 2(k) hereof.

Section 9 Participant's Account

The General Partner shall maintain in its books, an account for each Participant which records the number of Share Units standing to the credit of the Participant. Share Units will be fully vested upon being credited to a Participant's account and the Participant's entitlement to payment of Share Units at the termination date shall not thereafter be subject to satisfaction of any requirements as to any minimum period of service as a member of the Board. Upon redemption of the Share Units by way of receipt of Common Units as provided for under Section 8.3 hereof or a cash payment as provided for under Section 8.6 hereof, such Share Units shall be cancelled and the number of Share Units standing to the credit of the Participant shall be reduced to reflect the cancellation of such Share Units. A written confirmation of the balance in the account shall be mailed by the General Partner to the Participant at least annually.

Section 10 Effective Date of the Plan

The effective date of the Plan shall be October 18, 2007.

Amendments to and Suspension or Termination of the Plan

10.1 The Board may, from time to time, amend, suspend or terminate the Plan in whole or in part; however, any such amendment, suspension or termination shall not adversely affect the rights of any Participant under any Agreement existing at the time of such amendment, suspension or termination without the consent of the affected Participant.

Section 11 Purchases on the Open Market

11.1 Purchases of Common Units pursuant to the Plan shall be made on the open market by a broker who is independent from the Partnership and who is a member of The National Association of Securities Dealers (the "Broker"). The Participant who wishes to redeem his or her Share Units under the Plan, shall designate a Broker to purchase Common Units on the open market and any such designation may be changed by the Participant from time to time. Upon designation of the Broker, or at any time thereafter, the General Partner may elect to provide the designated Broker with a letter agreement to be entered into and executed by the Broker, Participant and General Partner and such letter agreement would set forth, *inter alia*:

(i) the Broker's concurrence to being designated to act for the Participant, to acting for the Participant and dealing with the Participant's account in accordance with customary trade practice with a view to obtaining the best share price for the Participant, and to delivering to the Participant, or his/her representative or Beneficiary as the case may be, the share certificate for the Common Units purchased, upon payment by the General Partner of the purchase price and related reasonable and customary brokerage commission; and

(ii) the Partnership's agreement to notify the Broker of the number of Common Units to be purchased and to pay the purchase price and the related reasonable and customary brokerage commission in connection with the purchase of the Common Units,

provided however, that no terms of said letter agreement shall have the effect of making the Broker or deeming the Broker to be an agent of the Partnership, General Partner or an affiliate of (or not independent from) the Partnership for purposes of any applicable corporate, securities or stock exchange requirement.

11.2 The Share Units, and any related Common Units that may be delivered under the Plan, have not been registered under the *U.S.*

Securities Act of 1933 as of the effective date of the Plan, and the Partnership or General Partner has no obligation to register such units or shares. The said Common Units may not be offered or sold in the United States unless registered or an exemption from registration is available.

Section 12 Rights of Participants

12.1 Except as specifically set out in the Plan or an Agreement, no Eligible Director, Participant or other person shall have any claim or right to any Common Units or any other benefit in respect of Share Units granted pursuant to the Plan.

12.2 Under no circumstances shall Share Units be considered Common Units nor shall they entitle any Participant to exercise voting rights or any other rights attaching to the ownership of the Common Units, nor shall any Participant be considered the owner of the Common Units until after the date of the purchase of such Common Units on the open market.

12.3 Neither the Plan nor any grant thereunder shall be construed as granting a Participant a right to be retained as a director of the General Partner or a claim or right to any future grant of Share Units.

Section 13 Death of Participant

13.1 Subject to the requirements of applicable laws, a Participant may designate in writing, a person who is a dependant or relation of the Participant as a beneficiary to receive any benefits payable or due to the Participant under the Plan, upon the death of such Participant. The Participant may, subject to applicable laws, change such designation from time to time. Such designation or change shall be in such form and executed and filed in such manner as the Board may, from time to time, determine.

13.2 In the event of a Participant's death, any and all payments with respect to Share Units then credited to such Participant's account under the Plan shall become payable to the Participant's Beneficiary in accordance with Section 8 hereof.

Section 14 Compliance with Applicable Laws

Any obligation of the General Partner with respect to the Common Units pursuant to the terms of the Plan, is subject to compliance with all applicable laws and the rules of any stock exchange on which units of the Partnership are listed. Should the General Partner determine that it is not feasible to arrange for purchase and delivery of Common Units to the Participant in accordance with Section 8 in satisfaction of Share Units by reason of any such laws, such obligation shall be satisfied by means of an equivalent cash payment, calculated in accordance with the provisions of Section 8.6. The Participant shall comply with all such laws and furnish the General Partner with any and all information and undertakings as may be required to ensure compliance therewith.

Section 15 Withholding Taxes

The General Partner shall be entitled to deduct any amount of withholding taxes and other withholdings from any amount paid or credited hereunder, which taxes shall reduce the amounts to which the Participant is entitled.

Section 16 Transferability

In no event may the rights or interests of a Participant under the Plan be assigned, encumbered, pledged, transferred or alienated in any way, except to the extent that certain rights may pass to a Beneficiary upon death of a Participant, by will or by the laws of succession and distribution.

Section 17 Alteration of Number of Share Units Subject to the Plan

17.1 In the event that the Common Units are subdivided or consolidated into a different number of Common Units, or a dividend that is payable in Common Units (rather than in cash or in shares at the option of the shareholder) is declared on the Common Units, the number of Share Units then recorded in the Participant's account shall be adjusted to equal the number of Common Units which would be held by the Participant immediately after the dividend, subdivision or consolidation, should the Participant have held a number of Common Units equal to the number of Share Units recorded in the Participant's account on the record date fixed for such dividend, or the effective date of such subdivision or consolidation.

17.2 In the event that the outstanding Common Units are changed into, or exchanged for a different number or kind of securities of the Partnership or of another entity, whether through an arrangement, amalgamation or other similar statutory procedure, or a share recapitalization, then there shall be substituted for each Common Unit referred to in the Plan, the kind of securities into which each outstanding Common Unit shall be so changed or exchanged and an equitable adjustment shall be made, if required, in the number of Share Units then recorded in the Participant's account. Any such adjustment will be reasonably determined by the Board and will be effective and binding for all purposes.

17.3 In the event there is any distribution to all or substantially all the holders of Common Units of:

(i) equity interests of any class other than Common Units and other than equity interests distributed as a dividend which may be paid in shares at the option of the shareholder;

(ii) rights, options or warrants other than rights, options or warrants to subscribe for or purchase Common Units (or securities convertible or exchangeable into Common Units) for a period of not more than 45 days at a price per Common Unit (or having a conversion or exchange price per

Common Unit) of not less than 95% of the current market price of a Common Unit on the record date for such distribution;

(iii) instruments of indebtedness of the Partnership; or

(iv) assets (excluding dividends paid in the ordinary course),

then, in each such case, an equitable adjustment shall be made in the number of Share Units then recorded in a Participant's account, such adjustment will be reasonably determined by the Board and will be effective and binding for all purposes.

17.4 In the case of any substitution, change or adjustment as provided for in this section, the variation shall generally require that the dollar value of the Share Units then recorded in the Participant's account prior to such substitution, change or adjustment will be proportionately and appropriately varied so that it be equal to such dollar value after the variation. The "dollar value" for this purpose means the number of Share Units recorded on the day immediately prior to the date such substitution, change or adjustment is made multiplied by the Fair Market Value of a Common Unit determined on that same day.

17.5 In the event that, at the time contemplated for the purchase of Common Units under the Plan, there is no public market for the Common Units or for securities substituted therefor as provided by this section, the obligations of the General Partner under the Plan shall be met by a payment in cash in such amount as is reasonably determined by the Board to be fair and equitable in the circumstances.

17.6 Notwithstanding any other provision of the Plan, in no event shall any amount be paid to, or in respect of, a Participant under the Plan or pursuant to any other arrangement, and no Share Units will be granted nor will any credit be made to Participant's account under the Plan to compensate for a downward fluctuation in the price of the Common Units, nor will any other form of benefit be conferred upon, or in respect of, a Participant for such purpose.

Section 18 Unfunded Plan

Unless otherwise determined by the Board, the Plan shall be unfunded. To the extent that any person holds any rights by virtue of an election under the Plan, such rights, unless otherwise determined by the Board, shall be no greater than the rights of an unsecured general creditor of the General Partner.

Section 19 Governing Law

The Plan shall be governed by, and interpreted in accordance with, the laws in force in the State of Delaware.

Appendix A

The TC PipeLines GP, Inc.
Share Unit Plan for Non-Employee Directors (2007)

THIS AGREEMENT is made effective this · day of ·, 2007,

BETWEEN:

TC PipeLines GP, Inc. a corporation incorporated under the laws of Delaware having its registered office in Wilmington, Delaware (hereinafter called the "General Partner")

AND

[Name of Participant], residing at
[Address]
[City, State]

(hereinafter called the "Participant")

PURSUANT TO THE TC PIPELINES GP, INC. SHARE UNIT PLAN FOR NON-EMPLOYEE DIRECTORS (2007) OF THE GENERAL PARTNER AS AMENDED FROM TIME TO TIME (THE "PLAN") AND FOR GOOD AND VALUABLE CONSIDERATION, THE RECEIPT AND SUFFICIENCY OF WHICH IS HEREBY ACKNOWLEDGED, THE PARTIES AGREE AS FOLLOWS:

1. This Agreement sets out the terms, conditions and restrictions which, together with the terms, conditions and restrictions set out in the Plan, shall govern the rights and obligations of the parties hereto with respect to all of the Share Units which shall be credited to the Participant's account under the Plan while the Participant remains an Eligible Director, as well as with respect to the delivery of Common Units to the Participant in compliance with the terms of the Plan; defined terms not otherwise defined herein shall have the same meaning as in the Plan, the text of which as at the date of this Agreement is attached hereto under Schedule A.

2. As set out in Section 11 of the Plan, the Broker shall be designated by the Participant by a written notification to the General Partner under Section 3 hereof. Any designation shall include the name and address, telephone and fax numbers of the Broker.

3. Any notices to the General Partner under this Agreement shall be sent to the address indicated below, unless notice of change of address is given by the General Partner to the Participant in accordance with this Section 3. Any notices to the Participant under this

Agreement shall be sent, and delivery of Common Units in respect of Share Units shall be made, to the address indicated below, unless notice of change of address is given by the Participant to the General Partner in accordance with this Section 3. Any notices under this Agreement or the Plan shall be given by registered mail, facsimile, courier service or personal delivery as follows:

With respect to the General Partner:
450 – 1 Street SW
Calgary, Alberta
T2P 5H1
Attention: Corporate Secretary
Facsimile number: (403) 920-2460

With respect to the Participant:
Mr./Ms.[Name]
[Address]
[City, State, Zip Code] United States
Facsimile number: (·) ·

4. In case of any conflict between the text of the Plan and the text of this Agreement, the text of the Plan shall govern.

5. The General Partner and the Participant hereby agree to comply with terms of the Plan as it may be amended from time to time. Within 30 days of the date on which any Plan amendment becomes effective, the General Partner shall provide the Participant with an amended copy of the Plan together with a memo outlining the amendments made. The Participant also agrees to comply with any and all applicable laws and policies of regulatory authorities, to furnish to the General Partner any and all information and undertakings as may be required to permit compliance by the Participant or the General Partner with any such laws and to consent to any revisions of the Plan and this Agreement as may be required to permit compliance by the General Partner with any such laws and policies or as the General Partner determines to be necessary or desirable.

6. The Participant understands that there may be restrictions on the Participant's right to sell the Common Units related to any Share Units within the United States and accordingly, agrees not to do so without prior discussion with, and approval by, the General Partner.

7. This Agreement shall be governed by and interpreted in accordance with the laws in force in the State of Delaware.

8. In connection with the Participant's execution of this Agreement, the Participant provides the confirmations, which are included in Schedule B hereto, which is incorporated in and forms part of this Agreement.

IN WITNESS WHEREOF the Parties hereto have executed these presents as of the day and year first written above.

TC PipeLines GP, Inc.

Per: ______________________________

____
[Name of Participant]

Per:

Witness

Schedule B

To
The TC PipeLines GP, Inc.
Share Unit Plan for Non-Employee Directors (2007)

In connection with the Share Units to be credited to the Participant's account and the Participant's receipt of Common Units under the Plan, the Participant confirms that:

(1) The Participant will receive the Share Units and any related Common Units for its own account for investment and not with a view to, or for resale in connection with, any distribution thereof or of any interest therein that would violate the United States Securities Act of 1933 (the "Securities Act").

(2) The Participant agrees that the certificates representing any Common Units delivered under the Plan (and, until the transfer agent for the Common Units is otherwise advised by the General Partner, any certificates issued in exchange or substitution for or on registration of transfer of such securities) shall, at the request of the General Partner, on behalf of the Partnership, bear the following legend:

"THE COMMON UNITS EVIDENCED BY THIS UNIT CERTIFICATE HAVE NOT BEEN AND WILL NOT BE REGISTERED UNDER THE UNITED STATES SECURITIES ACT OF 1933 (THE "SECURITIES ACT"). ACCORDINGLY, THE UNITS MAY NOT BE SOLD, TRANSFERRED, PLEDGED OR OTHERWISE DISPOSED OF, EXCEPT IN COMPLIANCE WITH THE SECURITIES ACT OR AN EXEMPTION THEREFROM."

(3) The Participant has been afforded an opportunity to ask questions and receive answers concerning the terms and condition of the Plan and to obtain such additional information with respect to the Partnership and the Plan as the Participant has requested.

(4) The Participant is an "accredited investor" as defined in Rule 501(a) under the Securities Act.

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Section 7: EX-21.1 (SUBSIDIARIES OF THE REGISTRANT)

Exhibit 21.1

SUBSIDIARIES OF THE REGISTRANT

1. The Registrant holds a 98.9899 per cent limited partner interest in TC GL Intermediate Limited Partnership, a Delaware limited partnership.

2. Through its interest in TC GL Intermediate Limited Partnership, the Registrant holds a 46.45 per cent general partner interest in Great Lakes Gas Transmission Limited Partnership, a Delaware limited partnership.

3. The Registrant holds a 98.9899 per cent limited partner interest in TC PipeLines Intermediate Limited Partnership, a Delaware limited partnership.

4. Through its interest in TC PipeLines Intermediate Limited Partnership, the Registrant holds a 50 per cent general partner interest in Northern Border Pipeline Company, a Texas general partnership.

5. The Registrant holds a 98.9899 per cent limited partner interest in TC Tuscarora Intermediate Limited Partnership, a Delaware limited partnership.

6. Through its interest in TC Tuscarora Intermediate Limited Partnership, the Registrant wholly-owns TC Pipelines Tuscarora LLC, a Delaware limited liability company.

7. Through its interest in TC Tuscarora Intermediate Limited Partnership and TC Pipelines Tuscarora LLC, the Registrant wholly-owns Tuscarora Gas Transmission Company, a Nevada general partnership.

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Section 8: EX-23.1 (CONSENT OF KPMG LLP WITH RESPECT TO THE

FINANCIAL STATEMENTS OF TC PIPELINES, LP)

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of TC PipeLines GP, Inc., General Partner of TC PipeLines, LP

We consent to the incorporation by reference in the registration statement (No. 333-141488) on Form S-3 of TC PipeLines, LP of our reports dated February 27, 2008 with respect to the consolidated balance sheets of TC PipeLines, LP as of December 31, 2007 and 2006, and the related statements of income, comprehensive income, cash flows and changes in partners' equity for each of the years in the three-year period ended December 31, 2007 and the effectiveness of internal control over financial reporting as of December 31, 2007, which reports appear in the December 31, 2007 annual report on Form 10-K of TC PipeLines, LP.

/s/ KPMG LLP

Chartered Accountants

Calgary, Canada
February 27, 2008

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Section 9: EX-23.2 (CONSENT OF KPMG LLP WITH RESPECT TO THE FINANCIAL STATEMENTS OF GREAT LAKES GAS TRANSMISSION LIMITED)

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors of TC PipeLines GP, Inc., General Partner of TC PipeLines, LP

We consent to the incorporation by reference in the registration statement (No. 333-141488) on Form S-3 of TC Pipelines, LP of our report dated January 22, 2008, with respect to the consolidated balance sheets of Great Lakes Gas Transmission Limited Partnership and subsidiary as of December 31, 2007 and 2006, and the related consolidated statements of income and partners' capital and cash flows for each of the years in the three-year period ended December 31, 2007, and all related financial statement schedules, which report appears in the December 31, 2007 annual report on Form 10-K of TC Pipelines, LP.

/s/ KPMG LLP

Detroit, Michigan
February 27, 2008

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Section 10: EX-23.3 (CONSENT OF KPMG LLP WITH RESPECT TO THE FINANCIAL STATEMENTS OF NORTHERN BORDER PIPELINE COMPANY)

Exhibit 23.3

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors
TC PipeLines GP, Inc., General Partner of TC PipeLines, LP:

We consent to the incorporation by reference in the registration statement (No. 333-141488) on Form S-3 of TC PipeLines, LP of our report dated February 27, 2008 with respect to the balance sheets of Northern Border Pipeline Company as of December 31, 2007 and 2006, and the related statements of income, comprehensive income, cash flows, and changes in partners' equity for each of the years in the three-year period ended December 31, 2007, and the related financial statement schedule, which reports appear in the December 31, 2007 annual report on Form 10-K of TC PipeLines, LP.

/s/ KPMG LLP

Omaha, Nebraska
February 27, 2008

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Section 11: EX-31.1 (CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT)

Exhibit 31.1

CERTIFICATION OF
PRINCIPAL EXECUTIVE OFFICER

I, Russell K. Girling, certify that:

1. I have reviewed this annual report on Form 10-K of TC PipeLines, LP;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15 (f) and 15d-15(f)) for the registrant and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluations; and

   d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation, of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Dated: February 28, 2008

/s/ Russell K. Girling
Russell K. Girling
Chief Executive Officer
TC PipeLines GP, Inc., as general partner of
TC PipeLines, LP

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Section 12: EX-31.2 (CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT)

Exhibit 31.2

CERTIFICATION OF
PRINCIPAL FINANCIAL OFFICER

I, Amy W. Leong, certify that:

1. I have reviewed this annual report on Form 10-K of TC PipeLines, LP;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15 (f) and 15d-15(f)) for the registrant and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluations; and

   d) disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer(s) and I have disclosed, based on our most recent evaluation, of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Dated: February 28, 2008

/s/ Amy W. Leong
Amy W. Leong

Principal Financial Officer and Controller
TC PipeLines GP, Inc., as general partner of
TC Pipelines, LP

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Section 13: EX-32.1 (CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT)

Exhibit 32.1

CERTIFICATION OF
PRINCIPAL EXECUTIVE OFFICER

I, Russell K. Girling Chairman, Chief Executive Officer of TC PipeLines GP, Inc., the general partner of TC PipeLines, LP (the Partnership), in compliance with 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 hereby certify, to the best of my knowledge**,** in connection with the Partnership's Annual Report on Form 10-K for the period ended December 31, 2007 as filed with the Securities and Exchange Commission (the Report) on the date hereof, that:

· the Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

· the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

Dated: February 28, 2008

/s/ Russell K. Girling
Russell K. Girling
Chief Executive Officer
TC PipeLines GP, Inc., as general partner of
TC PipeLines, LP

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Section 14: EX-32.2 (CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT)

Exhibit 32.2

CERTIFICATION OF
PRINCIPAL FINANCIAL OFFICER

I, Amy W. Leong, Principal Financial Officer and Controller of TC PipeLines GP, Inc., the general partner of TC PipeLines, LP (the Partnership), in compliance with 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 hereby certify, to the best of my knowledge**,** in connection with the Partnership's Annual Report on Form 10-K for the period ended December 31, 2007 as filed with the Securities and Exchange Commission (the Report) on the date hereof, that:

· the Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

· the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

Dated: February 28, 2008

/s/ Amy W. Leong
Amy W. Leong
Principal Financial Officer and Controller
TC PipeLines GP, Inc., as general partner of
TC PipeLines, LP

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)

þ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended September 30, 2008

or

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from __________ to __________

Commission file number 1-4174

THE WILLIAMS COMPANIES, INC.
(Exact name of registrant as specified in its charter)

DELAWARE	73-0569878
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
ONE WILLIAMS CENTER, TULSA, OKLAHOMA	74172
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number: (918) 573-2000

NO CHANGE

Former name, former address and former fiscal year, if changed since last report.

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes þ No o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer þ	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act.) Yes o No þ

Indicate the number of shares outstanding of each of the issuer's classes of common stock as of the latest practicable date.

Class	Outstanding at October 31, 2008
Common Stock, $1 par value	578,674,347 Shares

The Williams Companies, Inc.

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Certain matters contained in this report include "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. These statements discuss our expected future results based on current and pending business operations. We make these forward-looking statements in reliance on the safe harbor protections provided under the Private Securities Litigation Reform Act of 1995.

All statements, other than statements of historical facts, included in this report which address activities, events or developments that we expect, believe or anticipate will exist or may occur in the future, are forward-looking statements. Forward-looking statements can be identified by various forms of words such as "anticipates," "believes," "could," "may," "should," "continues," "estimates," "expects," "forecasts," "might," "planned," "potential," "projects," "scheduled" or similar expressions. These forward-looking statements include, among others, statements regarding:

- Amounts and nature of future capital expenditures;
- Expansion and growth of our business and operations;
- Financial condition and liquidity;
- Business strategy;
- Estimates of proved gas and oil reserves;
- Reserve potential;
- Development drilling potential;
- Cash flow from operations or results of operations;
- Seasonality of certain business segments;
- Natural gas and natural gas liquids prices and demand.

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Forward-looking statements are based on numerous assumptions, uncertainties and risks that could cause future events or results to be materially different from those stated or implied in this document. Many of the factors that will determine these results are beyond our ability to control or project. Specific factors which could cause actual results to differ from those in the forward-looking statements include:

- Availability of supplies (including the uncertainties inherent in assessing and estimating future natural gas reserves), market demand, volatility of prices, and increased costs of capital;
- Inflation, interest rates, fluctuation in foreign exchange, and general economic conditions;
- The strength and financial resources of our competitors;
- Development of alternative energy sources;
- The impact of operational and development hazards;
- Costs of, changes in, or the results of laws, government regulations including proposed climate change legislation, environmental liabilities, litigation, and rate proceedings;
- Changes in the current geopolitical situation;
- Risks related to strategy and financing, including restrictions stemming from our debt agreements, future changes in our credit ratings and the availability and cost of credit;
- Risks associated with future weather conditions;
- Our ability to successfully manage the risks associated with selling and marketing products in the wholesale energy markets;
- Acts of terrorism;
- Additional risks described in our filings with the Securities and Exchange Commission.

Given the uncertainties and risk factors that could cause our actual results to differ materially from those contained in any forward-looking statement, we caution investors not to unduly rely on our forward-looking statements. We disclaim any obligations to and do not intend to update the above list or to announce publicly the result of any revisions to any of the forward-looking statements to reflect future events or developments.

In addition to causing our actual results to differ, the factors listed above and referred to below may cause our intentions to change from those statements of intention set forth in this report. Such changes in our intentions may also cause our results to differ. We may change our intentions, at any time and without notice, based upon changes in such factors, our assumptions, or otherwise.

Because forward-looking statements involve risks and uncertainties, we caution that there are important factors, in addition to those listed above, that may cause actual results to differ materially from those contained in the forward-looking statements. For a detailed discussion of those factors, see Part I, Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2007, and Part II, Item 1A. Risk Factors of this Form 10-Q.

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The Williams Companies, Inc.
Consolidated Statement of Income
(Unaudited)

(Dollars in millions, except per-share amounts)	Three months ended September 30, 2008	Three months ended September 30, 2007	Nine months ended September 30, 2008	Nine months ended September 30, 2007
Revenues:				
Exploration & Production	$ 883	$ 499	$ 2,607	$ 1,521
Gas Pipeline	407	392	1,226	1,178
Midstream Gas & Liquids	1,436	1,360	4,747	3,605
Gas Marketing Services	1,716	1,247	5,376	3,929
Other	6	7	18	20
Intercompany eliminations	(1,181)	(645)	(3,754)	(2,201)
Total revenues	3,267	2,860	10,220	8,052
Segment costs and expenses:				
Costs and operating expenses	2,386	2,222	7,506	6,245
Selling, general and administrative expenses	133	107	375	317
Other income — net	—	(2)	(152)	(38)
Total segment costs and expenses	2,519	2,327	7,729	6,524
General corporate expenses	34	40	118	116
Operating income (loss):				
Exploration & Production	356	159	1,273	546
Gas Pipeline	152	162	486	473
Midstream Gas & Liquids	226	279	743	669
Gas Marketing Services	16	(67)	(9)	(160)
Other	(2)	—	(2)	—
General corporate expenses	(34)	(40)	(118)	(116)
Total operating income	714	493	2,373	1,412
Interest accrued	(166)	(171)	(496)	(515)
Interest capitalized	16	9	40	21
Investing income	65	78	175	196
Minority interest in income of consolidated subsidiaries	(55)	(29)	(157)	(68)
Other income — net	2	8	7	12
Income from continuing operations before income taxes	576	388	1,942	1,058
Provision for income taxes	207	160	738	417
Income from continuing operations	369	228	1,204	641
Income (loss) from discontinued operations	(3)	(30)	99	124
Net income	$ 366	$ 198	$ 1,303	$ 765
Basic earnings per common share:				
Income from continuing operations	$ .63	$ .38	$ 2.07	$ 1.07
Income (loss) from discontinued operations	—	(.05)	.17	.21
Net income	$ .63	$ .33	$ 2.24	$ 1.28
Weighted-average shares (thousands)	577,448	596,836	582,105	598,124
Diluted earnings per common share:				
Income from continuing operations	$ .62	$ .38	$ 2.02	$ 1.05
Income (loss) from discontinued operations	—	(.05)	.17	.20
Net income	$ .62	$ .33	$ 2.19	$ 1.25
Weighted-average shares (thousands)	589,138	610,651	594,630	611,761

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Cash dividends declared per common share	$ .11	$ .10	$ .32	$ .29

See accompanying notes.

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The Williams Companies, Inc.
Consolidated Balance Sheet
(Unaudited)

(Dollars in millions, except per-share amounts)	September 30, 2008	December 31, 2007
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,524	$ 1,699
Accounts and notes receivable (net of allowance of $38 at September 30, 2008 and $27 at December 31, 2007)	1,089	1,192
Inventories	324	209
Derivative assets	2,091	1,736
Assets of discontinued operations	16	185
Deferred income taxes	72	199
Other current assets and deferred charges	365	318
Total current assets	5,481	5,538
Investments	990	901
Property, plant and equipment, at cost	25,335	22,787
Less accumulated depreciation, depletion, and amortization	(7,686)	(6,806)
Property, plant and equipment — net	17,649	15,981
Derivative assets	1,008	859
Goodwill	1,011	1,011
Other assets and deferred charges	754	771
Total assets	$ 26,893	$ 25,061
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 1,072	$ 1,131
Accrued liabilities	1,144	1,158
Derivative liabilities	1,968	1,824
Liabilities of discontinued operations	13	175
Long-term debt due within one year	84	143
Total current liabilities	4,281	4,431
Long-term debt	7,827	7,757
Deferred income taxes	3,525	2,996
Derivative liabilities	1,002	1,139
Other liabilities and deferred income	1,045	933
Contingent liabilities and commitments (Note 12)		
Minority interests in consolidated subsidiaries	639	1,430
Stockholders' equity:		
Common stock (960 million shares authorized at $1 par value; 613 million shares issued at September 30, 2008 and 608 million shares issued at December 31, 2007)	613	608
Capital in excess of par value	8,077	6,748
Retained earnings (deficit)	823	(293)
Accumulated other comprehensive income (loss)	102	(121)
	9,615	6,942
Less treasury stock, at cost (35 million shares of common stock at September 30, 2008 and 22 million shares at December 31, 2007)	(1,041)	(567)
Total stockholders' equity	8,574	6,375
Total liabilities and stockholders' equity	$ 26,893	$ 25,061

See accompanying notes.

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The Williams Companies, Inc.
Consolidated Statement of Cash Flows
(Unaudited)

(Dollars in millions)	Nine months ended September 30, 2008	Nine months ended September 30, 2007
OPERATING ACTIVITIES:		
Net income	$ 1,303	$ 765
Adjustments to reconcile to net cash provided by operations:		
Reclassification of deferred net hedge gains related to sale of power business	—	(429)
Depreciation, depletion and amortization	953	792
Provision for deferred income taxes	497	445
Provision for loss on investments, property and other assets	19	136
Net gain on disposition of assets	(37)	(20)
Gain on sale of contractual production rights	(148)	—
Minority interest in income of consolidated subsidiaries	157	68
Amortization of stock-based awards	33	58
Cash provided (used) by changes in current assets and liabilities:		
Accounts and notes receivable	278	(72)
Inventories	(111)	23
Margin deposits and customer margin deposits payable	72	31
Other current assets and deferred charges	(78)	(11)
Accounts payable	(252)	(2)
Accrued liabilities	17	(250)
Changes in current and noncurrent derivative assets and liabilities	(103)	200
Other, including changes in noncurrent assets and liabilities	6	(57)
Net cash provided by operating activities	2,606	1,677
FINANCING ACTIVITIES:		
Proceeds from long-term debt	674	184
Payments of long-term debt	(634)	(318)
Proceeds from issuance of common stock	32	37
Proceeds from sale of limited partner units of consolidated partnerships	362	—
Tax benefit of stock-based awards	21	21
Dividends paid	(186)	(174)
Purchase of treasury stock	(474)	(234)
Dividends and distributions paid to minority interests	(90)	(57)
Changes in restricted cash	(20)	(4)
Changes in cash overdrafts	4	43
Other — net	(5)	(6)
Net cash used by financing activities	(316)	(508)
INVESTING ACTIVITIES:		
Property, plant and equipment:		
Capital expenditures	(2,593)	(2,100)
Net proceeds from dispositions	37	1
Changes in accounts payable and accrued liabilities	2	34
Proceeds from sale of discontinued operations	22	—
Purchases of investments/advances to affiliates	(105)	(37)
Purchases of auction rate securities	—	(304)
Proceeds from sales of auction rate securities	—	353
Proceeds from sale of contractual production rights	148	—
Proceeds from dispositions of investments and other assets	25	65
Other — net	(1)	5
Net cash used by investing activities	(2,465)	(1,983)
Decrease in cash and cash equivalents	(175)	(814)
Cash and cash equivalents at beginning of period	1,699	2,269
Cash and cash equivalents at end of period	$ 1,524	$ 1,455

See accompanying notes.

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The Williams Companies, Inc.
Notes to Consolidated Financial Statements
(Unaudited)

Note 1. General

Our accompanying interim consolidated financial statements do not include all the notes in our annual financial statements and, therefore, should be read in conjunction with the consolidated financial statements and notes thereto in our Annual Report on Form 10-K. The accompanying unaudited financial statements include all normal recurring adjustments that, in the opinion of our management, are necessary to present fairly our financial position at September 30, 2008, and results of operations for the three and nine months ended September 30, 2008 and 2007 and cash flows for the nine months ended September 30, 2008 and 2007.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and accompanying notes. Actual results could differ from those estimates.

Recent Market Events

The recent instability in financial markets has created global concerns about the liquidity of financial institutions and is having overarching impacts on the economy as a whole. In this volatile economic environment, many financial markets, institutions and other businesses remain under considerable stress. In addition, oil and gas prices have recently experienced significant declines. These events are impacting our business. However, we note the following:

- We are reducing our levels of expected capital expenditures.
- As of September 30, 2008, we have approximately $1.5 billion of cash and cash equivalents and nearly $2.6 billion of available capacity under our credit facilities.
- We have no significant debt maturities until 2011.
- Our risk from our net credit exposure to derivative counterparties, considering master netting agreements and collateral support, is not significant. Our net credit exposure as of September 30, 2008, related to derivative assets is $384 million, net of $54 million of collateral support. This exposure is concentrated with investment grade financial institution counterparties.

To the extent that these recent events drive sustained lower energy commodity prices, it will negatively impact our future results of operations and cash flow from operations and could result in a further reduction in capital expenditures. These impacts could also include the future nonperformance of counterparties or impairments of goodwill and long-lived assets.

Note 2. Basis of Presentation

Discontinued Operations

In accordance with the provisions related to discontinued operations within Statement of Financial Accounting Standards (SFAS) No. 144, “Accounting for the Impairment or Disposal of Long-Lived Assets,” the accompanying consolidated financial statements and notes reflect the results of operations and financial position of our former power business as discontinued operations. (See Note 3.) These operations included a 7,500-megawatt portfolio of power-related contracts that was sold in 2007 and our natural-gas fired electric generating plant located in Hazleton, Pennsylvania (Hazleton) that was sold in March 2008, in addition to other power-related assets.

Unless indicated otherwise, the information in the Notes to Consolidated Financial Statements relates to our continuing operations.

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Notes (Continued)

Master Limited Partnerships

We currently own approximately 23.6 percent of Williams Partners L.P., including the interests of the general partner, which is wholly owned by us, and incentive distribution rights. Considering the presumption of control of the general partner in accordance with Emerging Issues Task Force (EITF) Issue No. 04-5, "Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights," we consolidate Williams Partners L.P. within our Midstream Gas & Liquids (Midstream) segment.

In January 2008, Williams Pipeline Partners L.P. completed its initial public offering of 16.25 million common units at a price of $20 per unit. In February 2008, the underwriters exercised their right to purchase an additional 1.65 million common units at the same price. The initial asset of the partnership is a 35 percent interest in Northwest Pipeline GP (Northwest Pipeline). Upon completion of these transactions, we now own approximately 47.7 percent of the interests in Williams Pipeline Partners L.P., including the interests of the general partner, which is wholly owned by us, and incentive distribution rights. In accordance with EITF Issue No. 04-5, we consolidate Williams Pipeline Partners L.P. within our Gas Pipeline segment due to our control through the general partner.

Note 3. Discontinued Operations

The summarized results of discontinued operations and summarized assets and liabilities of discontinued operations primarily reflect our former power business except where noted otherwise.

Summarized Results of Discontinued Operations

The following table presents the summarized results of discontinued operations for the three and nine months ended September 30, 2008 and 2007.

	Three months ended September 30,		Nine months ended September 30,	
	2008	2007	2008	2007
	(Millions)		(Millions)	
Revenues	$ —	$ 703	$ 5	$ 2,210
Income (loss) from discontinued operations before income taxes	(4)	(52)	159	324
(Impairments) and gain (loss) on sales	8	2	8	(124)
(Provision) benefit for income taxes	(7)	20	(68)	(76)
Income (loss) from discontinued operations	$ (3)	$ (30)	$ 99	$ 124

Income (loss) from discontinued operations before income taxes for the nine months ended September 30, 2008, includes $128 million of gains from the favorable resolution of matters involving pipeline transportation rates associated with our former Alaska operations and $54 million of income from a reduction of remaining amounts accrued in excess of our obligation associated with the Trans-Alaska Pipeline System Quality Bank (see Note 12). These gains are partially offset by a $10 million charge from a settlement primarily related to the sale of natural gas liquids pipeline systems in 2002 (see Note 12) and a charge of $10 million associated with an oil purchase contract related to our former Alaska refinery.

Income (loss) from discontinued operations before income taxes for the nine months ended September 30, 2007, includes a gain of $429 million (reported in *revenues* of discontinued operations) associated with the reclassification of deferred net hedge gains from *accumulated other comprehensive income* to earnings in second-quarter 2007. This reclassification was based on the determination that the forecasted transactions related to the derivative cash flow hedges being sold were probable of not occurring. The three and nine months ended September 30, 2007, includes unrealized mark-to-market losses of $49 million and $72 million, respectively.

(Impairments) and gain (loss) on sales for the three and nine months ended September 30, 2008, primarily represents $9 million of final proceeds from the sale of our former power business.

(*Impairments) and gain (loss) on sales* for the nine months ended September 30, 2007, includes impairments of $111 million related to the carrying value of certain derivative contracts for which we had previously elected the normal purchases and normal sales exception under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," and, accordingly, were no longer recording at fair value, and $13 million related to our natural gas-fired electric generating plant near Hazleton, Pennsylvania. These impairments were based on our comparison of the carrying value to the estimate of fair value less cost to sell.

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Notes (Continued)

Summarized Assets and Liabilities of Discontinued Operations

The following table presents the summarized assets and liabilities of discontinued operations as of September 30, 2008 and December 31, 2007. The September 30, 2008, and December 31, 2007, balances for *derivative assets* and *derivative liabilities* represent contracts remaining to be assigned to the purchaser of our former power business, entirely offset by reciprocal positions with that same party. We continue to pursue assignment of the remaining contracts. The December 31, 2007, balance of *property, plant and equipment — net* includes Hazleton. These assets were sold in a March 2008 transaction for $8 million.

	September 30, 2008	December 31, 2007
	(Millions)	
Derivative assets	$ 11	$ 114
Accounts receivable — net	5	55
Other current assets	—	3
Total current assets	16	172
Property, plant and equipment — net	—	8
Other noncurrent assets	—	5
Total noncurrent assets	—	13
Total assets	$ 16	$ 185
Derivative liabilities	$ 11	$ 114
Other current liabilities	2	61
Total current liabilities	13	175
Total liabilities	$ 13	$ 175

Note 4. Asset Sales, Impairments and Other Accruals

The following table presents significant gains or losses from asset sales, impairments and other accruals or adjustments reflected in *other income — net* within *segment costs and expenses*.

	Three months ended September 30,		Nine months ended September 30,	
	2008	2007	2008	2007
	(Millions)		(Millions)	
Exploration & Production				
Gain on sale of contractual right to an international production payment	$ —	$ —	$(148)	$ —
Impairment of certain natural gas producing properties	14	—	14	—
Gas Pipeline				
Income from change in estimate related to a regulatory liability	—	—	—	(17)
Income from payments received for a terminated firm transportation agreement on Grays Harbor lateral. Associated with this gain is interest income of $2 million, which is included in *investing income*	—	(12)	—	(18)
Gain on sale of certain south Texas assets	(10)	—	(10)	—

In January 2008, we sold a contractual right to a production payment on certain future international hydrocarbon production for $148 million. In the first quarter of 2008, we received $118 million in cash, with the remainder placed in escrow subject to certain post-closing conditions and adjustments. We recognized a pre-tax gain of $118 million in the first quarter of 2008 related to the initial cash received. In the second quarter of 2008, the remaining cash was received from escrow and recognized as income.

Investing income within our Other segment includes gains from the sales of cost-based investments of $10 million and $15 million for the nine months ended September 30, 2008 and 2007, respectively.

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Notes (Continued)

Note 5. Provision for Income Taxes

The *provision for income taxes* includes:

	Three months ended September 30, 2008	Three months ended September 30, 2007	Nine months ended September 30, 2008	Nine months ended September 30, 2007
	(Millions)		(Millions)	
Current:				
Federal	$ 33	$ 8	$ 299	$ 5
State	(11)	6	34	7
Foreign	10	12	39	37
	32	26	372	49
Deferred:				
Federal	149	118	312	319
State	22	11	41	33
Foreign	4	5	13	16
	175	134	366	368
Total provision	$ 207	$ 160	$ 738	$ 417

The effective income tax rates for the three and nine months ended September 30, 2008, are greater than the federal statutory rate due primarily to the effect of state income taxes.

The effective income tax rates for the three and nine months ended September 30, 2007, are greater than the federal statutory rate due primarily to the effect of state income taxes and taxes on foreign operations. The higher effective tax rate for the nine months ended September 30, 2007, was partially offset by a benefit recognized based on a favorable private letter ruling received from the Internal Revenue Service concerning our securities litigation settlement and fees, a portion of which were previously treated as nondeductible.

During the next twelve months, we do not expect settlement of any unrecognized tax benefit associated with domestic or international matters under audit to have a material impact on our financial position.

Note 6. Earnings Per Common Share from Continuing Operations

Basic and diluted earnings per common share are computed as follows:

	Three months ended September 30, 2008	Three months ended September 30, 2007	Nine months ended September 30, 2008	Nine months ended September 30, 2007
	(Dollars in millions, except per-share amounts; shares in thousands)			
Income from continuing operations available to common stockholders for basic and diluted earnings per common share (1)	$ 369	$ 228	$ 1,204	$ 641
Basic weighted-average shares (2)	577,448	596,836	582,105	598,124
Effect of dilutive securities:				
Nonvested restricted stock units	1,304	1,769	1,337	1,553
Stock options	3,468	4,726	4,003	4,762
Convertible debentures (3)	6,918	7,320	7,185	7,322
Diluted weighted-average shares	589,138	610,651	594,630	611,761
Earnings per common share from continuing operations:				
Basic	$ .63	$ .38	$ 2.07	$ 1.07
Diluted	$ .62	$ .38	$ 2.02	$ 1.05

(1) The three and nine month periods for both years include \$1 million and \$2 million, respectively, of interest expense, net of tax, associated with our convertible debentures. These amounts have been added back to *income from continuing operations available to common stockholders* to calculate diluted earnings per common share.

(2) Since third-quarter 2007, we have purchased 29 million shares of our common stock under a stock repurchase program (see Note 11).

(3) During third-quarter 2008, we converted $25 million of our 5.5 percent junior subordinated convertible debentures in exchange for 2 million shares of our common stock.

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Notes (Continued)

The table below includes information related to stock options that were outstanding at September 30 of each respective year but have been excluded from the computation of weighted-average stock options due to the option exercise price exceeding the third quarter weighted-average market price of our common shares.

	September 30, 2008	September 30, 2007
Options excluded (millions)	1.9	1.9
Weighted-average exercise prices of options excluded	$ 37.04	$ 37.56
Exercise price ranges of options excluded	$32.05 - $42.29	$33.51 - $42.29
Third quarter weighted-average market price	$ 30.22	$ 32.56

Note 7. Employee Benefit Plans

Net periodic benefit expense for the three and nine months ended September 30, 2008 and 2007 are as follows:

	Pension Benefits			
	Three months ended September 30,		Nine months ended September 30,	
	2008	2007	2008	2007
	(Millions)		(Millions)	
Components of net periodic pension expense:				
Service cost	$ 6	$ 5	$ 17	$ 17
Interest cost	15	13	45	40
Expected return on plan assets	(20)	(18)	(59)	(54)
Amortization of net actuarial loss	3	5	10	14
Net periodic pension expense	$ 4	$ 5	$ 13	$ 17

	Other Postretirement Benefits			
	Three months ended September 30,		Nine months ended September 30,	
	2008	2007	2008	2007
	(Millions)		(Millions)	
Components of net periodic other postretirement benefit expense:				
Service cost	$ 1	$ 1	$ 2	$ 2
Interest cost	5	5	14	13
Expected return on plan assets	(4)	(3)	(10)	(9)
Regulatory asset amortization	1	1	3	4
Net periodic other postretirement benefit expense	$ 3	$ 4	$ 9	$ 10

During the nine months ended September 30, 2008, we contributed $37 million to our pension plans and $11 million to our other postretirement benefit plans. We presently anticipate making additional contributions of approximately $25 million to our pension plans in the remainder of 2008 for a total of approximately $62 million. We presently anticipate making additional contributions of approximately $4 million to our other postretirement benefit plans in 2008 for a total of approximately $15 million.

The assets and liabilities recorded on the Consolidated Balance Sheet at September 30, 2008, representing the funded status of the pension and other postretirement benefit plans, use various assumptions including expected long-term rates of return on plan assets and discount rates. Considering the decline in the overall equity markets during 2008, the expected return on plan assets may not be achieved during 2008. Additionally, the 2008 increase in interest rates on high-quality corporate bonds could result in higher discount rates, resulting in lower plan obligations. As a result, the pension and other postretirement benefit plan assets and liabilities recorded as of September 30, 2008, may not represent the actual funded status of the plans as of that date. The annual measurement of the funded status of the plans will occur as of December 31, 2008. The impact of the differences between actual and assumed outcomes and changes in assumptions will likely cause a significant net actuarial loss and will be recognized in other comprehensive income, net of taxes, and amortized in net periodic benefit expense beginning in 2009.

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Notes (Continued)

Note 8. Inventories

Inventories at September 30, 2008 and December 31, 2007 are as follows:

	September 30, 2008	December 31, 2007
	(Millions)	
Natural gas liquids (NGLs)	$ 146	$ 66
Natural gas in underground storage	74	45
Materials, supplies and other	104	98
	$ 324	$ 209

Note 9. Debt and Banking Arrangements

Long-Term Debt

Revolving credit and letter of credit facilities (credit facilities)

At September 30, 2008, no loans are outstanding under our credit facilities. Letters of credit issued under our facilities are:

	Letters of Credit at September 30, 2008
	(Millions)
$500 million unsecured credit facilities	$ —
$700 million unsecured credit facilities	$ 237
$1.5 billion unsecured credit facility	$ 28

Lehman Commercial Paper Inc., which is committed to fund up to $70 million of our $1.5 billion revolving credit facility, has filed for bankruptcy. Lehman Brothers Commercial Bank, which has not filed for bankruptcy, is committed to fund up to $12 million of Williams Partners L.P.'s $200 million revolving credit facility. We expect that our ability to borrow under these facilities is reduced by these committed amounts. The committed amounts of other participating banks under these agreements remain in effect and are not impacted by the above.

Exploration & Production's credit agreement

In February 2007, Exploration & Production entered into a five-year unsecured credit agreement with certain banks in order to reduce margin requirements related to our hedging activities as well as lower transaction fees. In June 2008, the agreement was extended through December 2013.

Issuances and retirements

On January 15, 2008, Transcontinental Gas Pipe Line Corporation (Transco) retired $100 million of 6.25 percent senior unsecured notes due January 15, 2008, with proceeds borrowed under our $1.5 billion unsecured credit facility.

On April 15, 2008, Transco retired a $75 million adjustable rate unsecured note due April 15, 2008, with proceeds borrowed under our $1.5 billion unsecured credit facility.

On May 22, 2008, Transco issued $250 million aggregate principal amount of 6.05 percent senior unsecured notes due 2018 to certain institutional investors in a Rule 144A private debt placement. A portion of these proceeds was used to repay Transco's $100 million and $75 million loans from January 2008 and April 2008, respectively, under our $1.5 billion unsecured credit facility. In September 2008, Transco completed an exchange of these notes for substantially identical new notes that are registered under the Securities Act of 1933, as amended.

On May 22, 2008, Northwest Pipeline issued $250 million aggregate principal amount of 6.05 percent senior unsecured notes due 2018 to certain institutional investors in a Rule 144A private debt placement. These proceeds were used to repay Northwest Pipeline's $250 million loan from December 2007 under our $1.5 billion unsecured credit facility. In September 2008, Northwest Pipeline completed an exchange of these notes for substantially identical new notes that are registered under the Securities Act of 1933, as amended.

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Notes (Continued)

Note 10. Fair Value Measurements

Adoption of SFAS No. 157

SFAS No. 157, "Fair Value Measurements" (SFAS 157), establishes a framework for fair value measurements in the financial statements by providing a definition of fair value, provides guidance on the methods used to estimate fair value and expands disclosures about fair value measurements. On January 1, 2008, we applied SFAS 157 for our assets and liabilities that are measured at fair value on a recurring basis, primarily our energy derivatives. Upon applying SFAS 157, we changed our valuation methodology to consider our nonperformance risk in estimating the fair value of our liabilities. The initial adoption of SFAS 157 had no material impact on our Consolidated Financial Statements. In February 2008, the Financial Accounting Standards Board (FASB) issued FASB Staff Position (FSP) FAS 157-2, permitting entities to delay application of SFAS 157 to fiscal years beginning after November 15, 2008, for nonfinancial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). Beginning January 1, 2009, we will apply SFAS 157 fair value requirements to nonfinancial assets and nonfinancial liabilities that are not recognized or disclosed at fair value on a recurring basis. SFAS 157 requires two distinct transition approaches: (1) cumulative-effect adjustment to beginning retained earnings for certain financial instrument transactions and (2) prospectively as of the date of adoption through earnings or other comprehensive income, as applicable, for all other instruments. Upon adopting SFAS 157, we applied a prospective transition as we did not have financial instrument transactions that required a cumulative-effect adjustment to beginning retained earnings.

Fair value is the price that would be received to sell an asset or the amount paid to transfer a liability in an orderly transaction between market participants (an exit price) at the measurement date. Fair value is a market based measurement considered from the perspective of a market participant. We use market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation. These inputs can be readily observable, market corroborated, or unobservable. We apply both market and income approaches for recurring fair value measurements using the best available information while utilizing valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs.

SFAS 157 establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). We classify fair value balances based on the observability of those inputs. The three levels of the fair value hierarchy are as follows:

- Level 1 — Quoted prices in active markets for identical assets or liabilities that we have the ability to access. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Our Level 1 primarily consists of financial instruments that are exchange-traded, including certain instruments that were part of sales transactions in 2007 and remain to be assigned to the purchaser. These unassigned instruments are entirely offset by reciprocal positions entered into directly with the purchaser. These reciprocal positions have also been included in Level 1.

- Level 2 — Inputs are other than quoted prices in active markets included in Level 1, that are either directly or indirectly observable. These inputs are either directly observable in the marketplace or indirectly observable through corroboration with market data for substantially the full contractual term of the asset or liability being measured. Our Level 2 primarily consists of over-the-counter (OTC) instruments such as forwards and swaps.

- Level 3 — Includes inputs that are not observable for which there is little, if any, market activity for the asset or liability being measured. These inputs reflect management's best estimate of the assumptions market participants would use in determining fair value. Our Level 3 consists of instruments valued using industry standard pricing models and other valuation methods that utilize unobservable pricing inputs that are significant to the overall fair value. Instruments in this category primarily include OTC options.

In valuing certain contracts, the inputs used to measure fair value may fall into different levels of the fair value hierarchy. For disclosure purposes, assets and liabilities are classified in their entirety in the fair value hierarchy level based on the lowest level of input that is significant to the overall fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy levels.

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Notes (Continued)

The following table sets forth by level within the fair value hierarchy our assets and liabilities that are measured at fair value on a recurring basis.

Fair Value Measurements at September 30, 2008 Using:

	Quoted Prices in Active Markets for Identical Assets or Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(Millions)		
Assets:				
Energy derivatives	$ 1,008	$ 1,705	$ 386	$ 3,099
Other assets	12	—	10	22
Total assets	$ 1,020	$ 1,705	$ 396	$ 3,121
Liabilities:				
Energy derivatives	$ 950	$ 1,916	$ 104	$ 2,970
Total liabilities	$ 950	$ 1,916	$ 104	$ 2,970

Energy derivatives include commodity based exchange-traded contracts and OTC contracts. Exchange-traded contracts include futures and options. OTC contracts include forwards, swaps and options.

Many contracts have bid and ask prices that can be observed in the market. Our policy is to use a mid-market pricing (the mid-point price between bid and ask prices) convention to value individual positions and then adjust on a portfolio level to a point within the bid and ask range that represents our best estimate of fair value. For offsetting positions by location, the mid-market price is used to measure both the long and short positions.

The determination of fair value also incorporates the time value of money and credit risk factors including the credit standing of the counterparties involved, master netting arrangements, the impact of credit enhancements (such as cash deposits and letters of credit) and our nonperformance risk on our liabilities.

Exchange-traded contracts include New York Mercantile Exchange and Intercontinental Exchange contracts and are valued based on quoted prices in these active markets and are classified within Level 1.

Contracts for which fair value can be estimated from executed transactions or broker quotes corroborated by other market data are generally classified within Level 2. These broker quotes are based on observable market prices at which transactions could currently be executed. In certain instances where these inputs are not observable for all periods, relationships of observable market data and historical observations are used as a means to estimate fair value. Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2.

Certain instruments trade in less active markets with lower availability of pricing information requiring valuation models using inputs that may not be readily observable or corroborated by other market data. These instruments are classified within Level 3 when these inputs have a significant impact on the measurement of fair value. The fair value of options is estimated using an industry standard Black-Scholes option pricing model. Certain inputs into the model are generally observable, such as commodity prices and interest rates, whereas other model inputs, such as implied volatility by location, is unobservable and requires judgment in estimating. The instruments included in Level 3 at September 30, 2008, predominantly consist of options that primarily hedge future sales of production from our Exploration & Production segment, are structured as costless collars and are financially settled.

The following tables set forth a reconciliation of changes in the fair value of net derivatives and other assets classified as Level 3 in the fair value hierarchy.

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Level 3 Fair Value Measurements Using Significant Unobservable Inputs
Three Months Ended September 30, 2008

	Net Derivatives	Other Assets
	(Millions)	
Balance as of July 1, 2008	$ (641)	$ 10
Realized and unrealized gains (losses):		
Included in *income from continuing operations*	22	—
Included in *other comprehensive income* (See Note 13)	870	—
Purchases, issuances, and settlements	27	—
Transfers in/out of Level 3	4	—
Balance as of September 30, 2008	$ 282	$ 10
Unrealized gains included in *income from continuing operations* relating to instruments still held at September 30, 2008	$ 23	$ —

Level 3 Fair Value Measurements Using Significant Unobservable Inputs
Nine Months Ended September 30, 2008

	Net Derivatives	Other Assets
	(Millions)	
Balance as of January 1, 2008	$ (14)	$ 10
Realized and unrealized gains (losses):		
Included in *income from continuing operations*	(7)	—
Included in *other comprehensive income* (See Note 13)	210	—
Purchases, issuances, and settlements	91	—
Transfers in/out of Level 3	2	—
Balance as of September 30, 2008	$ 282	$ 10
Unrealized losses included in *income from continuing operations* relating to instruments still held at September 30, 2008	$ (21)	$ —

Realized and unrealized gains (losses) included in *income from continuing operations* for the above period are reported in *revenues* in our Consolidated Statement of Income.

Note 11. Stockholders' Equity

During 2008, we purchased 13 million shares of our common stock for $474 million at an average cost of $36.76 per share completing our $1 billion common stock repurchase program. This stock repurchase is recorded in *treasury stock* on our Consolidated Balance Sheet. From the program's inception in third-quarter 2007 to its completion in July 2008, we purchased 29 million shares of our common stock reaching the $1 billion limit (including transaction costs) authorized by our Board of Directors. Our overall average cost per share was $34.74.

At December 31, 2007, we held all of Williams Partners L.P.'s seven million subordinated units outstanding. In February 2008, these subordinated units were converted into common units of Williams Partners L.P. due to the achievement of certain financial targets that resulted in the early termination of the subordination period. While these subordinated units were outstanding, other issuances of partnership units by Williams Partners L.P. had preferential rights and the proceeds from these issuances in excess of the book basis of assets acquired by Williams Partners L.P. were therefore reflected as minority interest on our Consolidated Balance Sheet rather than as equity. Due to the conversion of the subordinated units, these original issuances of partnership units no longer have preferential rights and now represent the lowest level of equity securities issued by Williams Partners L.P. In accordance with our policy regarding the issuance of equity of a consolidated subsidiary, such issuances of nonpreferential equity are accounted for as capital transactions and no gain or loss is recognized. Therefore, as a result of the first-quarter conversion, we recognized a decrease to minority interest and a corresponding increase to stockholders' equity of approximately $1.2 billion.

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Notes (Continued)

Note 12. Contingent Liabilities

Rate and Regulatory Matters and Related Litigation

Our interstate pipeline subsidiaries have various regulatory proceedings pending. As a result, a portion of the revenues of these subsidiaries has been collected subject to refund. We have accrued a liability for these potential refunds as of September 30, 2008, which we believe is adequate for any refunds that may be required.

Issues Resulting from California Energy Crisis

Our former power business was engaged in power marketing in various geographic areas, including California. Prices charged for power by us and other traders and generators in California and other western states in 2000 and 2001 were challenged in various proceedings, including those before the U.S. Federal Energy Regulatory Commission (FERC). These challenges included refund proceedings, summer 2002 90-day contracts, investigations of alleged market manipulation including withholding, gas indices and other gaming of the market, new long-term power sales to the State of California that were subsequently challenged and civil litigation relating to certain of these issues. We have entered into settlements with the State of California (State Settlement), major California utilities (Utilities Settlement), and others that substantially resolved each of these issues with these parties.

As a result of a June 2008 U.S. Supreme Court decision, certain contracts that we entered into during 2000 and 2001 may be subject to partial refunds depending on the results of further proceedings at the FERC. These contracts, under which we sold electricity, totaled approximately $89 million in revenue. While we are not a party to the cases involved in the U.S. Supreme Court decision, the buyer of electricity from us is a party to the cases and claims that we must refund to the buyer any loss it suffers due to the FERC's reconsideration of the contract terms at issue in the decision.

Certain other issues also remain open at the FERC and for other nonsettling parties.

Refund proceedings

Although we entered into the State Settlement and Utilities Settlement, which resolved the refund issues among the settling parties, we continue to have potential refund exposure to nonsettling parties, such as the counterparty to the contracts described above and various California end users that did not participate in the Utilities Settlement. As a part of the Utilities Settlement, we funded escrow accounts that we anticipate will satisfy any ultimate refund determinations in favor of the nonsettling parties including interest on refund amounts that we might owe to settling and nonsettling parties. We are also owed interest from counterparties in the California market during the refund period for which we have recorded a receivable totaling approximately $24 million at September 30, 2008. Collection of the interest and the payment of interest on refund amounts from the escrow accounts is subject to the conclusion of this proceeding. Therefore, we continue to participate in the FERC refund case and related proceedings.

Challenges to virtually every aspect of the refund proceedings, including the refund period, continue to be made. Because of our settlements, we do not expect that the final resolution of refund obligations will have a material impact on us. Due to the ongoing proceedings and challenges, the final refund calculation has not been made and aspects of the refund calculation process remain unsettled.

Reporting of Natural Gas-Related Information to Trade Publications

Civil suits based on allegations of manipulating published gas price indices have been brought against us and others, in each case seeking an unspecified amount of damages. We are currently a defendant in:

- State court litigation in California brought on behalf of certain business and governmental entities that purchased gas for their use.
- Class action litigation and other litigation originally filed in state court in Colorado, Kansas, Missouri, Tennessee and Wisconsin brought on behalf of direct and indirect purchasers of gas in those states. On October 29, 2008, the Tennessee appellate court reversed the state court's dismissal of the plaintiffs' claims on federal preemption grounds and sent the case back to the lower court for further proceedings. The Missouri case has been remanded to Missouri state court. The cases in the other jurisdictions have been removed and transferred to the federal court in Nevada. On February 19, 2008, the federal court granted summary judgment in the Colorado case in favor of us and most of the other defendants. We expect that the Colorado plaintiffs will appeal.

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Notes (Continued)

Mobile Bay Expansion

In 2002, an administrative law judge at the FERC issued an initial decision in Transco's 2001 general rate case which, among other things, rejected the recovery of the costs of Transco's Mobile Bay expansion project from its shippers on a "rolled-in" basis and found that incremental pricing for the Mobile Bay expansion project is just and reasonable. In 2004, the FERC issued an Order on Initial Decision in which it reversed certain parts of the administrative law judge's decision and accepted Transco's proposal for rolled-in rates. Gas Marketing Services holds long-term transportation capacity on the Mobile Bay expansion project. Certain parties filed appeals in federal court seeking to overturn the FERC's ruling on the rolled-in rates. On April 2, 2008, Gas Marketing Services executed an agreement that settled this matter for $10 million, which was accrued in 2007.

Environmental Matters

Continuing operations

Since 1989, our Transco subsidiary has had studies underway to test certain of its facilities for the presence of toxic and hazardous substances to determine to what extent, if any, remediation may be necessary. Transco has responded to data requests from the U.S. Environmental Protection Agency (EPA) and state agencies regarding such potential contamination of certain of its sites. Transco has identified polychlorinated biphenyl (PCB) contamination in compressor systems, soils and related properties at certain compressor station sites. Transco has also been involved in negotiations with the EPA and state agencies to develop screening, sampling and cleanup programs. In addition, Transco commenced negotiations with certain environmental authorities and other parties concerning investigative and remedial actions relative to potential mercury contamination at certain gas metering sites. The costs of any such remediation will depend upon the scope of the remediation. At September 30, 2008, we had accrued liabilities of $5 million related to PCB contamination, potential mercury contamination, and other toxic and hazardous substances. Transco has been identified as a potentially responsible party at various Superfund and state waste disposal sites. Based on present volumetric estimates and other factors, we have estimated our aggregate exposure for remediation of these sites to be less than $500,000, which is included in the environmental accrual discussed above. We expect that these costs will be recoverable through Transco's rates.

Beginning in the mid-1980s, our Northwest Pipeline subsidiary evaluated many of its facilities for the presence of toxic and hazardous substances to determine to what extent, if any, remediation might be necessary. Consistent with other natural gas transmission companies, Northwest Pipeline identified PCB contamination in air compressor systems, soils and related properties at certain compressor station sites. Similarly, Northwest Pipeline identified hydrocarbon impacts at these facilities due to the former use of earthen pits and mercury contamination at certain gas metering sites. The PCBs were remediated pursuant to a Consent Decree with the EPA in the late 1980s and Northwest Pipeline conducted a voluntary clean-up of the hydrocarbon and mercury impacts in the early 1990s. In 2005, the Washington Department of Ecology required Northwest Pipeline to reevaluate its previous mercury clean-ups in Washington. Consequently, Northwest Pipeline is conducting additional remediation activities at certain sites to comply with Washington's current environmental standards. At September 30, 2008, we have accrued liabilities of $7 million for these costs. We expect that these costs will be recoverable through Northwest Pipeline's rates.

In March 2008, the EPA issued a new air quality standard for ground level ozone. We currently do not know if our interstate gas pipelines will be impacted by the new standard. If they are, we will likely incur additional capital expenditures to comply. At this time we are unable to estimate the cost of these additions that may be required to meet the new regulations. We expect that costs associated with these compliance efforts will be recoverable through rates.

We also accrue environmental remediation costs for natural gas underground storage facilities, primarily related to soil and groundwater contamination. At September 30, 2008, we have accrued liabilities totaling $6 million for these costs.

Williams Production RMT Company performed voluntary audits of its 2006 and 2007 compliance with state and federal air regulations. In June 2007, pursuant to Colorado's audit immunity privilege law, we disclosed to the Colorado Department of Public Health and Environment (CDPHE) that certain aspects of our facilities were not in compliance. We also described corrective actions that had or would be taken to remedy the issues. The CDPHE denied our request for penalty immunity and proposed a penalty. In a separate matter, the CDPHE issued a Notice of Violation (NOV) to Williams Production RMT Company in 2006 related to operating permits for our Roan Cliffs and Hayburn gas plants in Garfield County, Colorado. We settled both of these matters with the CDPHE in June 2008 and paid a $93,300 civil penalty and made a $373,200 contribution to a state environmental program.

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Notes (Continued)

In April 2007, the CDPHE issued an NOV to Williams Production RMT Company related to alleged air permit violations at the Rifle Station natural gas dehydration facility located in Garfield County, Colorado. The Rifle Station facility had been shut down prior to our receipt of the NOV and, except for some minor operations, remains closed. We settled the matter with the CDPHE in June 2008 and paid an $11,200 civil penalty and made a $44,800 contribution to a state environmental program.

In April 2007, the New Mexico Environment Department's Air Quality Bureau (NMED) issued an NOV to Williams Four Corners, LLC (Four Corners) that alleged various emission and reporting violations in connection with our Lybrook gas processing plant's flare and leak detection and repair program. In December 2007, the NMED proposed a penalty of approximately $3 million. In July 2008, the NMED issued an NOV to Four Corners that alleged air emissions permit exceedances for three glycol dehydrators at one of our compressor facilities and proposed a penalty of approximately $103,000. We are discussing the proposed penalties with the NMED.

In March 2008, the EPA proposed a penalty of $370,000 for alleged violations relating to leak detection and repair program delays at our Ignacio gas plant in Colorado and for alleged permit violations at a compressor station. We met with the EPA and are exchanging information in order to resolve the issues.

In September 2007, the EPA requested, and our Transco subsidiary later provided, information regarding natural gas compressor stations in the states of Mississippi and Alabama as part of the EPA's investigation of our compliance with the Clean Air Act. On March 28, 2008, the EPA issued NOVs alleging violations of Clean Air Act requirements at these compressor stations. We met with the EPA in May 2008 and submitted our response denying the allegations in June 2008.

Former operations, including operations classified as discontinued

In connection with the sale of certain assets and businesses, we have retained responsibility, through indemnification of the purchasers, for environmental and other liabilities existing at the time the sale was consummated, as described below.

Agrico

In connection with the 1987 sale of the assets of Agrico Chemical Company, we agreed to indemnify the purchaser for environmental cleanup costs resulting from certain conditions at specified locations to the extent such costs exceed a specified amount. At September 30, 2008, we have accrued liabilities of $9 million for such excess costs.

Other

At September 30, 2008, we have accrued environmental liabilities of $15 million related primarily to our:

- Potential indemnification obligations to purchasers of our former retail petroleum and refining operations;
- Former propane marketing operations, bio-energy facilities, petroleum products and natural gas pipelines;
- Discontinued petroleum refining facilities; and
- Former exploration and production and mining operations.

Certain of our subsidiaries have been identified as potentially responsible parties at various Superfund and state waste disposal sites. In addition, these subsidiaries have incurred, or are alleged to have incurred, various other hazardous materials removal or remediation obligations under environmental laws.

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Notes (Continued)

Summary of environmental matters

Actual costs incurred for these matters could be substantially greater than amounts accrued depending on the actual number of contaminated sites identified, the actual amount and extent of contamination discovered, the final cleanup standards mandated by the EPA and other governmental authorities and other factors, but the amount cannot be reasonably estimated at this time.

Other Legal Matters

Will Price (formerly Quinque)

In 2001, fourteen of our entities were named as defendants in a nationwide class action lawsuit in Kansas state court that had been pending against other defendants, generally pipeline and gathering companies, since 2000. The plaintiffs alleged that the defendants have engaged in mismeasurement techniques that distort the heating content of natural gas, resulting in an alleged underpayment of royalties to the class of producer plaintiffs and sought an unspecified amount of damages. The fourth amended petition, which was filed in 2003, deleted all of our defendant entities except two Midstream subsidiaries. All remaining defendants have opposed class certification and a hearing on plaintiffs' second motion to certify the class was held in April 2005. We are awaiting a decision from the court. The amount of any possible liability cannot be reasonably estimated at this time.

Grynberg

In 1998, the U.S. Department of Justice (DOJ) informed us that Jack Grynberg, an individual, had filed claims on behalf of himself and the federal government, in the United States District Court for the District of Colorado under the False Claims Act against us and certain of our wholly owned subsidiaries. The claims sought an unspecified amount of royalties allegedly not paid to the federal government, treble damages, a civil penalty, attorneys' fees, and costs. In connection with our sales of Kern River Gas Transmission in 2002 and Texas Gas Transmission Corporation in 2003, we agreed to indemnify the purchasers for any liability relating to this claim, including legal fees. The maximum amount of future payments that we could potentially be required to pay under these indemnifications depends upon the ultimate resolution of the claim and cannot currently be determined. Grynberg had also filed claims against approximately 300 other energy companies alleging that the defendants violated the False Claims Act in connection with the measurement, royalty valuation and purchase of hydrocarbons. In 1999, the DOJ announced that it would not intervene in any of the Grynberg cases. Also in 1999, the Panel on Multi-District Litigation transferred all of these cases, including those filed against us, to the federal court in Wyoming for pre-trial purposes. Grynberg's measurement claims remained pending against us and the other defendants; the court previously dismissed Grynberg's royalty valuation claims. In 2005, the court-appointed special master entered a report which recommended that the claims against our Gas Pipeline and Midstream subsidiaries be dismissed but upheld the claims against our Exploration & Production subsidiaries against our jurisdictional challenge. In October 2006, the District Court dismissed all claims against us and our wholly owned subsidiaries. In November 2006, Grynberg filed his notice of appeal with the Tenth Circuit Court of Appeals and the court held oral argument on September 25, 2008.

In August 2002, Jack J. Grynberg, and Celeste C. Grynberg, Trustee on Behalf of the Rachel Susan Grynberg Trust, and the Stephen Mark Grynberg Trust, served us and one of our Exploration & Production subsidiaries with a complaint in state court in Denver, Colorado. The complaint alleges that we have used mismeasurement techniques that distort the British Thermal Unit heating content of natural gas, resulting in the alleged underpayment of royalties to Grynberg and other independent natural gas producers. The complaint also alleges that we inappropriately took deductions from the gross value of their natural gas and made other royalty valuation errors. Under various theories of relief, the plaintiff was seeking actual damages between $2 million and $20 million based on interest rate variations and punitive damages in the amount of approximately $1 million. In 2004, Grynberg filed an amended complaint against one of our Exploration & Production subsidiaries. In 2005, the parties agreed to dismiss mismeasurement claims. In September 2008, the court ruled in our favor on motions for summary judgment dismissing various claims. Trial on the remaining breach of contract and accounting claims has been set for November 2008. The amount of any possible liability cannot be reasonably estimated at this time.

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Securities class actions

Numerous shareholder class action suits were filed against us in 2002 in the United States District Court for the Northern District of Oklahoma. The majority of the suits alleged that we and co-defendants, WilTel, previously an owned subsidiary known as Williams Communications, and certain corporate officers, acted jointly and separately to inflate the stock price of both companies. WilTel was dismissed as a defendant as a result of its bankruptcy. These cases were consolidated and an order was issued requiring separate amended consolidated complaints by our equity holders and WilTel equity holders. The underwriter defendants have requested indemnification and defense from these cases. If we grant the requested indemnifications to the underwriters, any related settlement costs will not be covered by our insurance policies. We covered the cost of defending the underwriters. In 2002, the amended complaints of the WilTel securities holders and of our securities holders added numerous claims. On February 9, 2007, the court gave its final approval to our settlement with our securities holders. We entered into indemnity agreements with certain of our insurers to ensure their timely payment related to this settlement. The carrying value of our estimated liability related to these agreements is immaterial because we believe the likelihood of any future performance is remote.

On July 6, 2007, the court granted various defendants' motions for summary judgment and entered judgment for us and the other defendants in the WilTel matter. The plaintiffs appealed the court's judgment. Any obligation of ours to the WilTel equity holders as a result of a settlement, or as a result of trial in the event of a successful appeal of the court's judgment, will not likely be covered by insurance because our insurance coverage has been fully utilized by the settlement described above. The extent of any such obligation is presently unknown and cannot be estimated, but it is reasonably possible that our exposure could materially exceed amounts accrued for this matter.

TAPS Quality Bank

One of our subsidiaries, Williams Alaska Petroleum, Inc. (WAPI), has been engaged in administrative litigation being conducted jointly by the FERC and the Regulatory Commission of Alaska (RCA) concerning the Trans-Alaska Pipeline System (TAPS) Quality Bank. In 2004, the FERC and RCA presiding administrative law judges rendered their joint and individual initial decisions, and we accrued approximately $134 million based on our computation and assessment of ultimate ruling terms that were considered probable. Our additional potential refund liability terminated on March 31, 2004, when WAPI sold the Alaska refinery and ceased shipping on the TAPS pipeline. We subsequently accrued additional amounts for interest.

In 2006, the FERC entered its final order, which the RCA adopted. On February 15, 2008, the Alaska Supreme Court upheld the RCA's order and on March 16, 2008, the D.C. Circuit Court of Appeals upheld the FERC's order. We have paid substantially all amounts invoiced by the Quality Bank Administrator and third parties, except certain disputed amounts which remain accrued.

We believe that the likelihood of successful appeal by the counterparties is remote, considering the relevant facts and circumstances related to this matter, including the favorable 2008 D.C. Circuit Court of Appeals rulings, and our assessment of the counterparties' limited remaining options. As a result, during the first quarter of 2008 we reduced remaining amounts accrued in excess of our estimated remaining obligation by $54 million.

On August 18, 2008, a counterparty requested a writ of certiorari from the U.S. Supreme Court to appeal the ruling of the D.C. Circuit Court of Appeals.

Redondo Beach taxes

In 2005, we and AES Redondo Beach, L.L.C. received a tax assessment letter from the city of Redondo Beach, California, in which the city asserted that taxes, interest and penalties were owed related to natural gas used at the generating facility operated by AES Redondo Beach. In connection with the sale of our power business (see Note 2), we and AES Redondo Beach agreed to equally share, for periods prior to the closing of the sale, any ultimate tax liability as well as the funding of amounts previously paid to the city under protest. In July, 2008, we settled all disputes with the city and they subsequently refunded all tax payments made under protest plus half of the earned interest on those amounts. We shared this refund with AES Redondo Beach.

Gulf Liquids litigation

Gulf Liquids contracted with Gulsby Engineering Inc. (Gulsby) and Gulsby-Bay for the construction of certain gas processing plants in Louisiana. National American Insurance Company (NAICO) and American Home Assurance Company provided payment and performance bonds for the projects. In 2001, the contractors and sureties filed multiple cases in Louisiana and Texas against Gulf Liquids and us.

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Notes (Continued)

In 2006, at the conclusion of the consolidated trial of the asserted contract and tort claims, the jury returned its actual and punitive damages verdict against us and Gulf Liquids. Based on our interpretation of the jury verdicts, we estimated exposure for actual damages of approximately $68 million plus potential interest of approximately $25 million, all of which have been accrued as of September 30, 2008. In addition, we concluded that it was reasonably possible that any ultimate judgment might have included additional amounts of approximately $199 million in excess of our accrual, which primarily represented our estimate of potential punitive damage exposure under Texas law.

From May through October 2007, the court entered seven post-trial orders in the case (interlocutory orders) which, among other things, overruled the verdict award of tort and punitive damages as well as any damages against us. The court also denied the plaintiffs' claims for attorneys' fees. On January 28, 2008, the court issued its judgment awarding damages against Gulf Liquids of approximately $11 million in favor of Gulsby and approximately $4 million in favor of Gulsby-Bay. Gulf Liquids, Gulsby, Gulsby-Bay, and NAICO are appealing the judgment. If the judgment is upheld on appeal, our liability will be substantially less than the amount of our accrual for these matters.

Wyoming severance taxes

In August 2006, the Wyoming Department of Audit (DOA) assessed our subsidiary, Williams Production RMT Company, for additional severance tax and interest for the production years 2000 through 2002. In addition, the DOA notified us of an increase in the taxable value of our interests for ad valorem tax purposes. We disputed the DOA's interpretation of the statutory obligation and appealed this assessment to the Wyoming State Board of Equalization (SBOE). The SBOE upheld the assessment and remanded it to the DOA to address the disallowance of a credit. The SBOE did not award interest on the assessment. We estimate that the amount of the additional severance and ad valorem taxes to be approximately $4 million. We appealed the SBOE decision to the Wyoming Supreme Court, which heard oral argument on August 12, 2008. If the DOA prevails in its interpretation of our obligation and applies the same basis of assessment to subsequent periods, it is reasonably possible that we could owe a total of approximately $23 million to $25 million in additional taxes and interest from January 1, 2003 through September 30, 2008.

Royalty litigation

In September 2006, royalty interest owners in Garfield County, Colorado, filed a class action suit in Colorado state court alleging that we improperly calculated oil and gas royalty payments, failed to account for the proceeds that we received from the sale of gas and extracted products, improperly charged certain expenses, and failed to refund amounts withheld in excess of ad valorem tax obligations. The plaintiffs claim that the class might be in excess of 500 individuals and seek an accounting and damages. The parties have reached a partial settlement agreement for an amount that was previously accrued. The partial settlement has received preliminary approval by the court, and we anticipate trial in late 2009 on remaining issues related to royalty payment calculation and obligations under specific lease provisions. We are not able to estimate the amount of any additional exposure at this time.

Certain other royalty matters are currently being litigated by other producers with a federal regulatory agency in Colorado and with a state agency in New Mexico. Although we are not a party to these matters, the final outcome of those cases might lead to a future unfavorable impact on our results of operations.

Other Divestiture Indemnifications

Pursuant to various purchase and sale agreements relating to divested businesses and assets, we have indemnified certain purchasers against liabilities that they may incur with respect to the businesses and assets acquired from us. The indemnities provided to the purchasers are customary in sale transactions and are contingent upon the purchasers incurring liabilities that are not otherwise recoverable from third parties. The indemnities generally relate to breach of warranties, tax, historic litigation, personal injury, environmental matters, right of way and other representations that we have provided.

We sold a natural gas liquids pipeline system in 2002, and in 2006, the purchaser of that system filed its complaint against us and our subsidiaries in state court in Houston, Texas. The purchaser alleged that we breached certain warranties under the purchase and sale agreement and sought approximately $18 million in damages and our specific performance under certain guarantees. The dispute was settled in June 2008 and all court cases have been dismissed.

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Notes (Continued)

At September 30, 2008, we do not expect any of the indemnities provided pursuant to the sales agreements to have a material impact on our future financial position. However, if a claim for indemnity is brought against us in the future, it may have a material adverse effect on our results of operations in the period in which the claim is made.

In addition to the foregoing, various other proceedings are pending against us which are incidental to our operations.

Summary

Litigation, arbitration, regulatory matters, and environmental matters are subject to inherent uncertainties. Were an unfavorable ruling to occur, there exists the possibility of a material adverse impact on the results of operations in the period in which the ruling occurs. Management, including internal counsel, currently believes that the ultimate resolution of the foregoing matters, taken as a whole and after consideration of amounts accrued, insurance coverage, recovery from customers or other indemnification arrangements, will not have a material adverse effect upon our future financial position.

Guarantees

In connection with agreements executed to resolve take-or-pay and other contract claims and to amend gas purchase contracts, Transco entered into certain settlements with producers that may require the indemnification of certain claims for additional royalties that the producers may be required to pay as a result of such settlements. Transco, through its agent, Gas Marketing Services, continues to purchase gas under contracts which extend, in some cases, through the life of the associated gas reserves. Certain of these contracts contain royalty indemnification provisions that have no carrying value. Producers have received certain demands and may receive other demands, which could result in claims pursuant to royalty indemnification provisions. Indemnification for royalties will depend on, among other things, the specific lease provisions between the producer and the lessor and the terms of the agreement between the producer and Transco. Consequently, the potential maximum future payments under such indemnification provisions cannot be determined. However, management believes that the probability of material payments is remote.

In connection with the 1993 public offering of units in the Williams Coal Seam Gas Royalty Trust (Royalty Trust), our Exploration & Production segment entered into a gas purchase contract for the purchase of natural gas in which the Royalty Trust holds a net profits interest. Under this agreement, we guarantee a minimum purchase price that the Royalty Trust will realize in the calculation of its net profits interest. We have an annual option to discontinue this minimum purchase price guarantee and pay solely based on an index price. The maximum potential future exposure associated with this guarantee is not determinable because it is dependent upon natural gas prices and production volumes. No amounts have been accrued for this contingent obligation as the index price continues to substantially exceed the minimum purchase price.

We are required by certain lenders to ensure that the interest rates received by them under various loan agreements are not reduced by taxes by providing for the reimbursement of any taxes required to be paid by the lender. The maximum potential amount of future payments under these indemnifications is based on the related borrowings. These indemnifications generally continue indefinitely unless limited by the underlying tax regulations and have no carrying value. We have never been called upon to perform under these indemnifications.

We have provided guarantees in the event of nonpayment by our previously owned communications subsidiary, WilTel, on certain lease performance obligations that extend through 2042. The maximum potential exposure is $42 million at September 30, 2008. Our exposure declines systematically throughout the remaining term of WilTel’s obligations. The carrying value of these guarantees is $38 million at September 30, 2008.

Former managing directors of Gulf Liquids are involved in litigation related to the construction of gas processing plants. Gulf Liquids has indemnity obligations to the former managing directors for legal fees and potential losses that may result from this litigation. Claims against these former managing directors have been settled and dismissed after payments on their behalf by directors and officers insurers. Some unresolved issues remain between us and these insurers, but no amounts have been accrued for any potential liability.

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Notes (Continued)

We have guaranteed the performance of a former subsidiary of our wholly owned subsidiary MAPCO Inc., under a coal supply contract. This guarantee was granted by MAPCO Inc. upon the sale of its former subsidiary to a third party in 1996. The guaranteed contract provides for an annual supply of a minimum of 2.25 million tons of coal. Our potential exposure is dependent on the difference between current market prices of coal and the pricing terms of the contract, both of which are variable, and the remaining term of the contract. Given the variability of the terms, the maximum future potential payments cannot be determined. We believe that our likelihood of performance under this guarantee is remote. In the event we are required to perform, we are fully indemnified by the purchaser of MAPCO Inc.'s former subsidiary. This guarantee expires in December 2010 and has no carrying value.

We have guaranteed commercial letters of credit totaling $20 million on behalf of ACCROVEN, an equity method investee. These expire in January 2009 and have no carrying value.

We have provided guarantees on behalf of certain entities in which we have an equity ownership interest. These generally guarantee operating performance measures and the maximum potential future exposure cannot be determined. There are no expiration dates associated with these guarantees. No amounts have been accrued at September 30, 2008.

Note 13. Comprehensive Income

Comprehensive income is as follows:

	Three months ended September 30,		Nine months ended September 30,	
	2008	2007	2008	2007
	(Millions)		(Millions)	
Net income	$ 366	$ 198	$ 1,303	$ 765
Other comprehensive income (loss):				
Net unrealized gains on derivative instruments	1,083	131	256	252
Net reclassification into earnings of derivative instrument (gains) losses	62	(32)	142	(476)
Foreign currency translation adjustments	(10)	25	(27)	56
Amortization of pension benefits net actuarial loss	3	5	10	14
Amortization of other postretirement benefits prior service cost	—	—	1	1
Other comprehensive income (loss) before taxes	1,138	129	382	(153)
Income tax benefit (provision) on other comprehensive income (loss)	(434)	(40)	(154)	80
Other comprehensive income (loss) before minority interest	704	89	228	(73)
Allocation of other comprehensive income (loss) to minority interest	(12)	—	(5)	—
Other comprehensive income (loss)	692	89	223	(73)
Comprehensive income	$ 1,058	$ 287	$ 1,526	$ 692

Net unrealized gains on derivative instruments represents changes in the fair value of certain derivative contracts that have been designated as cash flow hedges. The *net unrealized gains on derivative instruments* are as follows:

	Three months ended September 30,		Nine months ended September 30,	
	2008	2007	2008	2007
	(Millions)		(Millions)	
Net unrealized gains (losses) on:				
Forward natural gas purchases and sales	$ 1,034	$ 132	$ 274	$ 284
Forward natural gas liquids sales	50	(1)	(18)	(1)
Forward power purchases and sales	—	—	—	(31)
Other derivative instruments	(1)	—	—	—
	$ 1,083	$ 131	$ 256	$ 252

Net reclassification into earnings of derivative instrument (gains) losses for the nine months ended September 30, 2007, includes a gain of $429 million. This reclassification was based on the determination that the forecasted transactions related to the derivative cash flow hedges being sold as part of the sale of our power business were probable of not occurring.

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Notes (Continued)

Note 14. Segment Disclosures

Our reportable segments are strategic business units that offer different products and services. The segments are managed separately because each segment requires different technology, marketing strategies and industry knowledge. Our master limited partnerships, Williams Partners L.P. and Williams Pipeline Partners L.P., are consolidated within our Midstream and Gas Pipeline segments, respectively. (See Note 2.) Other primarily consists of corporate operations.

Performance Measurement

We currently evaluate performance based upon *segment profit (loss)* from operations, which includes *segment revenues* from external and internal customers, *segment costs and expenses*, *equity earnings (losses)* and *income (loss) from investments*, including impairments related to investments accounted for under the equity method. Intersegment sales are generally accounted for at current market prices as if the sales were to unaffiliated third parties.

External revenues of our Exploration & Production segment include third-party oil and gas sales, which are more than offset by transportation expenses and royalties due third parties on intersegment sales.

The following tables reflect the reconciliation of *segment revenues* and *segment profit (loss)* to *revenues* and *operating income (loss)* as reported in the Consolidated Statement of Income.

	Exploration & Production	Gas Pipeline	Midstream Gas & Liquids	Gas Marketing Services	Other	Eliminations	Total
				(Millions)			
Three months ended September 30, 2008							
Segment revenues:							
External	$ (79)	$ 403	$ 1,442	$ 1,499	$ 2	$ —	$ 3,267
Internal	962	4	(6)	217	4	(1,181)	—
Total revenues	$ 883	$ 407	$ 1,436	$ 1,716	$ 6	$ (1,181)	$ 3,267
Segment profit (loss)	$ 361	$ 173	$ 254	$ 16	$ (2)	$ —	$ 802
Less equity earnings	5	21	28	—	—	—	54
Segment operating income (loss)	$ 356	$ 152	$ 226	$ 16	$ (2)	$ —	748
General corporate expenses							(34)
Total operating income							$ 714
Three months ended September 30, 2007							
Segment revenues:							
External	$ (21)	$ 385	$ 1,350	$ 1,141	$ 5	$ —	$ 2,860
Internal	520	7	10	106	2	(645)	—
Total revenues	$ 499	$ 392	$ 1,360	$ 1,247	$ 7	$ (645)	$ 2,860
Segment profit (loss)	$ 169	$ 183	$ 300	$ (67)	$ —	$ —	$ 585
Less equity earnings	10	21	21	—	—	—	52
Segment operating income (loss)	$ 159	$ 162	$ 279	$ (67)	$ —	$ —	533
General corporate expenses							(40)
Total operating income							$ 493

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Notes (Continued)

	Exploration & Production	Gas Pipeline	Midstream Gas & Liquids	Gas Marketing Services	Other	Eliminations	Total
				(Millions)			
Nine months ended September 30, 2008							
Segment revenues:							
External	$ (206)	$ 1,200	$ 4,747	$ 4,472	$ 7	$ —	$10,220
Internal	2,813	26	—	904	11	(3,754)	—
Total revenues	$ 2,607	$ 1,226	$ 4,747	$ 5,376	$ 18	$ (3,754)	$10,220
Segment profit (loss)	$ 1,287	$ 532	$ 810	$ (9)	$ (2)	$ —	$ 2,618
Less equity earnings	14	46	67	—	—	—	127
Segment operating income (loss)	$ 1,273	$ 486	$ 743	$ (9)	$ (2)	$ —	2,491
General corporate expenses							(118)
Total operating income							$ 2,373
Nine months ended September 30, 2007							
Segment revenues:							
External	$ (97)	$ 1,156	$ 3,573	$ 3,411	$ 9	$ —	$ 8,052
Internal	1,618	22	32	518	11	(2,201)	—
Total revenues	$ 1,521	$ 1,178	$ 3,605	$ 3,929	$ 20	$ (2,201)	$ 8,052
Segment profit (loss)	$ 566	$ 513	$ 705	$ (160)	$ —	$ —	$ 1,624
Less equity earnings	20	40	36	—	—	—	96
Segment operating income (loss)	$ 546	$ 473	$ 669	$ (160)	$ —	$ —	1,528
General corporate expenses							(116)
Total operating income							$ 1,412

The following table reflects *total assets* by reporting segment.

	Total Assets	
	September 30, 2008	December 31, 2007
	(Millions)	
Exploration & Production (1)	$ 10,362	$ 8,692
Gas Pipeline	9,078	8,624
Midstream Gas & Liquids	7,371	6,604
Gas Marketing Services	4,460	4,437
Other	3,524	3,592
Eliminations	(7,918)	(7,073)
	26,877	24,876
Assets of discontinued operations	16	185
Total	$ 26,893	$ 25,061

(1) The increase in Exploration & Production's total assets is due primarily to an increase in derivative assets and an increase in property, plant and equipment — net. The derivative asset increase is primarily due to the impact of changes in commodity prices on existing forward derivative contracts. Exploration & Production's derivative assets are significantly offset by their derivative liabilities. The property, plant and equipment — net increase is primarily due to increased drilling activity.

Note 15. Recent Accounting Standards

Recent Accounting Standards

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements" (SFAS 157). This Statement establishes a framework for fair value measurements in the financial statements by providing a definition of fair value, provides guidance on the methods used to estimate fair value and expands disclosures about fair value measurements. SFAS 157 is effective for fiscal years beginning after November 15, 2007. In February 2008, the FASB issued FASB Staff Position (FSP) No. FAS 157-2, permitting entities to delay application of SFAS 157 to fiscal years beginning after November 15, 2008, for nonfinancial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). On January 1, 2008, we applied SFAS 157 to our assets and liabilities that are measured at fair value on a recurring basis, primarily our energy derivatives. See Note 10 for discussion of the adoption. Beginning January 1, 2009, we will apply SFAS 157 fair value requirements to nonfinancial assets and nonfinancial liabilities that are not recognized or disclosed on a recurring basis. Application will be prospective when nonrecurring fair value measurements are required. We will assess the impact on our Consolidated Financial Statements of applying these requirements to nonrecurring fair value measurements for nonfinancial assets and nonfinancial liabilities.

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Notes (Continued)

In December 2007, the FASB issued SFAS No. 141(R) "Business Combinations" (SFAS 141(R)). SFAS 141(R) applies to all business combinations and establishes guidance for recognizing and measuring identifiable assets acquired, liabilities assumed, noncontrolling interests in the acquiree and goodwill. Most of these items are recognized at their full fair value on the acquisition date, including acquisitions where the acquirer obtains control but less than 100 percent ownership in the acquiree. SFAS 141(R) also requires expensing of restructuring and acquisition-related costs as incurred and establishes disclosure requirements to enable the evaluation of the nature and financial effects of the business combination. SFAS 141(R) is effective for business combinations with an acquisition date in fiscal years beginning after December 15, 2008. We are currently evaluating the changes provided in this Statement.

In December 2007, the FASB issued SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements — an amendment of Accounting Research Bulletin No. 51" (SFAS 160). SFAS 160 establishes accounting and reporting standards for noncontrolling ownership interests in subsidiaries (previously referred to as minority interests). Noncontrolling ownership interests in consolidated subsidiaries will be presented in the consolidated balance sheet within stockholders' equity as a separate component from the parent's equity. Consolidated net income will now include earnings attributable to both the parent and the noncontrolling interests. Earnings per share will continue to be based on earnings attributable to only the parent company and does not change upon adoption of SFAS 160. SFAS 160 provides guidance on accounting for changes in the parent's ownership interest in a subsidiary, including transactions where control is retained and where control is relinquished. SFAS 160 also requires additional disclosure of information related to amounts attributable to the parent for income from continuing operations, discontinued operations and extraordinary items and reconciliations of the parent and noncontrolling interests' equity of a subsidiary. SFAS 160 is effective for fiscal years beginning after December 15, 2008, and early adoption is prohibited. The Statement will be applied prospectively to transactions involving noncontrolling interests, including noncontrolling interests that arose prior to the effective date, as of the beginning of the fiscal year it is initially adopted. However, the presentation of noncontrolling interests within stockholders' equity and the inclusion of earnings attributable to the noncontrolling interests in consolidated net income requires retrospective application to all periods presented. We will assess the impact on our Consolidated Financial Statements.

In March 2008, the FASB issued SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities — an amendment of FASB Statement No. 133" (SFAS 161). SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," currently establishes the disclosure requirements for derivative instruments and hedging activities. SFAS 161 amends and expands the disclosure requirements of Statement 133 with enhanced quantitative, qualitative and credit risk disclosures. The Statement requires quantitative disclosure in a tabular format about the fair values of derivative instruments, gains and losses on derivative instruments and information about where these items are reported in the financial statements. Also required in the tabular presentation is a separation of hedging and nonhedging activities. Qualitative disclosures include outlining objectives and strategies for using derivative instruments in terms of underlying risk exposures, use of derivatives for risk management and other purposes and accounting designation, and an understanding of the volume and purpose of derivative activity. Credit risk disclosures provide information about credit risk related contingent features included in derivative agreements. SFAS 161 also amends SFAS No. 107, "Disclosures about Fair Value of Financial Instruments," to clarify that disclosures about concentrations of credit risk should include derivative instruments. This Statement is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early application encouraged. We plan to apply this Statement beginning in 2009. This Statement encourages, but does not require, comparative disclosures for earlier periods at initial adoption. The application of this Statement will increase the disclosures in our Consolidated Financial Statements.

In June 2008, the FASB issued FASB Staff Position No. EITF 03-6-1, "Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities" (FSP EITF 03-6-1). FSP EITF 03-6-1 requires that unvested share-based payment awards containing nonforfeitable rights to dividends or dividend equivalents (whether paid or unpaid) be considered participating securities and included in the computation of earnings per share (EPS) pursuant to the two-class method of FASB Statement No. 128, "Earnings per Share." FSP EITF 03-6-1 is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those years. All prior-period EPS data presented shall be adjusted retrospectively to conform to this FSP. Early application is not permitted. This FSP is not anticipated to have a material impact on our EPS attributable to the common stockholders.

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Item 2

Management's Discussion and Analysis of Financial Condition and Results of Operations

Recent Market Events

The recent instability in financial markets has created global concerns about the liquidity of financial institutions and is having overarching impacts on the economy as a whole. In this volatile economic environment, many financial markets, institutions and other businesses remain under considerable stress. In addition, oil and gas prices have recently experienced significant declines. These events are impacting our business. However, we note the following:

- We are reducing our levels of expected capital expenditures.
- As of September 30, 2008, we have approximately $1.5 billion of cash and cash equivalents and nearly $2.6 billion of available capacity under our credit facilities. (See further discussion in Management's Discussion and Analysis of Financial Condition — Available Liquidity.)
- We have no significant debt maturities until 2011.
- Considering master netting agreements and collateral support, we do not have significant risk from our net credit exposure to derivative counterparties. (See further discussion in Energy Trading Activities — Counterparty Credit Considerations.)

To the extent that these recent events drive sustained lower energy commodity prices, it will negatively impact our future results of operations and cash flow from operations and could result in a further reduction in capital expenditures. These impacts could also include the future nonperformance of counterparties or impairments of goodwill and long-lived assets. In addition, the overall decline in equity markets in 2008 has negatively impacted our employee benefit plan assets and will likely increase expense in future periods. (See Note 7 of Notes to Consolidated Financial Statements.)

Company Outlook

Our plan for 2008 has been focused on disciplined growth. Our plans for the remainder of 2008 and into 2009 have been adjusted in light of lower energy commodity prices and the disruption in the financial markets. At present, we intend to continue our disciplined growth, but the level of our future investment will be adjusted as required to maintain adequate liquidity. Our objectives include continuing to improve EVA® and invest in our businesses in a way that meets customer needs and enhances our competitive position:

- Continue to increase natural gas production and reserves;
- Increase the scale of our gathering and processing business in key growth basins;
- Continue to invest in expansion projects on our interstate natural gas pipelines.

Potential risks and/or obstacles that could prevent us from achieving these objectives include:

- Availability of capital;
- Counterparty credit and performance risk;
- Volatility of commodity prices;
- Lower than expected levels of cash flow from operations;
- Decreased drilling success at Exploration & Production;
- Decreased drilling success or abandonment of projects by third parties served by Midstream and Gas Pipeline;

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Management's Discussion and Analysis (Continued)

- General economic, financial markets, or industry downturn;
- Changes in the current political and regulatory environment;
- Exposure associated with our efforts to resolve regulatory and litigation issues (see Note 12 of Notes to Consolidated Financial Statements).

We continue to address these risks through utilization of commodity hedging strategies, focused efforts to resolve regulatory issues and litigation claims, disciplined investment strategies, and maintaining at least $1 billion in liquidity from cash and cash equivalents and unused revolving credit facilities. In addition, we utilize master netting agreements and collateral requirements with our counterparties.

Our *income from continuing operations* for the nine months ended September 30, 2008, increased $563 million compared to the nine months ended September 30, 2007. This increase is reflective of:

- Higher net realized average prices and continued strong natural gas production growth at Exploration & Production;
- A pre-tax gain of $148 million at Exploration & Production on the sale of a contractual right to a production payment on certain future international hydrocarbon production;
- Favorable commodity price margins at Midstream.

See additional discussion in Results of Operations.

Our *net cash provided by operating activities* for the nine months ended September 30, 2008, increased $929 million compared to the nine months ended September 30, 2007, primarily due to our improved operating results. See additional discussion in Management's Discussion and Analysis of Financial Condition.

Recent Events

In September 2008, Hurricanes Gustav and Ike impacted our operations, primarily at Midstream. We estimate that our segment profit for third-quarter 2008 was decreased by approximately $50 million to $65 million due to downtime and charges for repairs and property insurance deductibles associated with Hurricanes Gustav and Ike. We also estimate that fourth-quarter 2008 pre-tax results will be reduced by approximately $10 million to $20 million due to downtime and reduced volumes. See additional discussion in Results of Operations — Segments, Gas Pipeline and Midstream Gas & Liquids.

In July 2008, we completed our stock repurchase program by reaching the $1 billion limit authorized by our Board of Directors. (See Note 11 of Notes to Consolidated Financial Statements.)

In 2008, we increased our positions by acquiring undeveloped leasehold acreage, producing properties and gathering facilities in the Piceance basin and undeveloped leasehold acreage and producing properties in the Fort Worth basin. See additional discussion in Results of Operations — Segments, Exploration & Production.

In 2008, we recognized pre-tax income of $172 million in *income from discontinued operations* related to our former Alaska operations. (See Note 3 of Notes to Consolidated Financial Statements.)

In 2008, we recognized income of $148 million related to the sale of a contractual right to a production payment on certain future international hydrocarbon production. See additional discussion in Results of Operations — Segments, Exploration & Production.

In January 2008, Williams Pipeline Partners L.P. completed its initial public offering. See additional discussion in Results of Operations — Segments, Gas Pipeline.

Transco's new rates became effective June 1, 2008. See additional discussion in Results of Operations — Segments, Gas Pipeline.

General

Unless indicated otherwise, the following discussion and analysis of Results of Operations and Financial Condition relates to our current continuing operations and should be read in conjunction with the Consolidated Financial Statements and notes thereto included in Item 1 of this document and our 2007 Annual Report on Form 10-K.

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Fair Value Measurements

On January 1, 2008, we adopted Statement of Financial Accounting Standards No. 157, "Fair Value Measurements" (SFAS 157), for our assets and liabilities that are measured at fair value on a recurring basis, primarily our energy derivatives. See Note 10 of Notes to Consolidated Financial Statements for disclosures regarding SFAS 157, including discussion of the fair value hierarchy levels and valuation methodologies.

Certain of our energy derivative assets and liabilities and other assets are valued using unobservable inputs and included in Level 3. At September 30, 2008, 13 percent of the total assets measured at fair value and four percent of the total liabilities measured at fair value are included in Level 3.

Certain instruments trade in markets with lower availability of pricing information requiring us to use unobservable inputs and are considered Level 3 in the fair value hierarchy. For Level 2 transactions, we do not make significant adjustments to observable prices in measuring fair value as we do not generally trade in inactive markets.

The determination of fair value also incorporates the time value of money and credit risk factors including the credit standing of the counterparties involved, master netting arrangements, the impact of credit enhancements (such as cash deposits and letters of credit) and our nonperformance risk on our liabilities. Considering these factors and that we do not have significant risk from our net credit exposure to derivative counterparties, the impact of credit risk is not significant to the overall fair value of our derivatives portfolio.

The instruments included in Level 3 at September 30, 2008, predominantly consist of options that primarily hedge future sales of production from our Exploration & Production segment, are structured as costless collars and are financially settled. The options are valued using an industry standard Black-Scholes option pricing model. Certain inputs into the model are generally observable, such as commodity prices and interest rates, whereas a significant input, implied volatility by location, is unobservable. The impact of volatility on changes in the overall fair value of the options structured as collars is reduced because of the offsetting nature of the put and call positions. The change in the overall fair value of instruments included in Level 3 primarily results from changes in commodity prices. The hedges are accounted for as cash flow hedges where net unrealized gains and losses from changes in fair value are recorded, to the extent effective, in *other comprehensive income* and subsequently impact earnings when the underlying hedged production is sold.

Exploration & Production has an unsecured credit agreement through December 2013 with certain banks which serves to reduce our usage of cash and other credit facilities for margin requirements related to options included in the facility.

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Management's Discussion and Analysis (Continued)

Results of Operations

Consolidated Overview

The following table and discussion is a summary of our consolidated results of operations for the three and nine months ended September 30, 2008, compared to the three and nine months ended September 30, 2007. The results of operations by segment are discussed in further detail following this consolidated overview discussion.

	Three months ended September 30,				Nine months ended September 30,			
	2008	2007	$ Change from 2007*	% Change from 2007*	2008	2007	$ Change from 2007*	% Change from 2007*
	(Millions)				(Millions)			
Revenues	$ 3,267	$ 2,860	+407	+14%	$10,220	$ 8,052	+2,168	+27%
Costs and expenses:								
Costs and operating expenses	2,386	2,222	–164	–7%	7,506	6,245	–1,261	–20%
Selling, general and administrative expenses	133	107	–26	–24%	375	317	–58	–18%
Other income — net	—	(2)	–2	–100%	(152)	(38)	+114	NM
General corporate expenses	34	40	+6	+15%	118	116	–2	–2%
Total costs and expenses	2,553	2,367			7,847	6,640		
Operating income	714	493			2,373	1,412		
Interest accrued — net	(150)	(162)	+12	+7%	(456)	(494)	+38	+8%
Investing income	65	78	–13	–17%	175	196	–21	–11%
Minority interest in income of consolidated subsidiaries	(55)	(29)	–26	–90%	(157)	(68)	–89	–131%
Other income — net	2	8	–6	–75%	7	12	–5	–42%
Income from continuing operations before income taxes	576	388			1,942	1,058		
Provision for income taxes	207	160	–47	–29%	738	417	–321	–77%
Income from continuing operations	369	228			1,204	641		
Income (loss) from discontinued operations	(3)	(30)	+27	+90%	99	124	–25	–20%
Net income	$ 366	$ 198			$ 1,303	$ 765		

*+ = Favorable change to *net income*; – = Unfavorable change to *net income*; NM = A percentage calculation is not meaningful due to change in signs, a zero-value denominator, or a percentage change greater than 200.

Three months ended September 30, 2008 vs. three months ended September 30, 2007

The increase in *revenues* is primarily due to higher production revenues at Exploration & Production resulting from both higher net realized average prices and increased production volumes sold. Midstream also experienced higher natural gas liquid (NGL) and olefin production revenues due primarily to higher prices, partially offset by lower volumes.

The increase in *costs and operating expenses* is primarily due to higher costs associated with our NGL and olefin production businesses at Midstream. Higher depreciation, depletion and amortization and higher operating taxes at Exploration & Production also contributed to our increased expenses.

The increase in *selling, general and administrative expenses (SG&A)* primarily includes the impact of higher staffing and compensation at Exploration & Production in support of increased operational activities.

Other income — net within *operating income* in third-quarter 2008 includes a gain of $10 million on the sale of certain south Texas assets at Gas Pipeline and $8 million of net gains on foreign currency exchanges at Midstream. These gains are partially offset by a $14 million impairment of certain natural gas producing properties at Exploration & Production.

Other income — net within *operating income* in third-quarter 2007 includes income of $12 million associated with a payment received for a terminated firm transportation agreement on Gas Pipeline's Grays Harbor lateral, partially offset by $6 million of net losses on foreign currency exchanges at Midstream.

The increase in *operating income* primarily reflects both higher net realized average prices and continued strong natural gas production growth at Exploration & Production.

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Management's Discussion and Analysis (Continued)

Interest accrued — net decreased primarily due to increased capitalized interest resulting from an increased level of capital expenditures. Additionally, the decrease was impacted by lower interest rates on debt issuances that occurred late in the fourth quarter 2007 and in the first half of 2008 for which the proceeds were primarily used to retire existing debt bearing higher interest rates.

The decrease in *investing income* is due primarily to a $17 million decrease in interest income largely a result of lower average interest rates in 2008 compared to 2007.

Minority interest in income of consolidated subsidiaries increased primarily due to the growth in the minority interest holdings of Williams Partners L.P. and Williams Pipeline Partners L.P.

Provision for income taxes increased primarily due to higher pre-tax income. See Note 5 of Notes to Consolidated Financial Statements for a discussion of the effective tax rates compared to the federal statutory rate for both periods.

See Note 3 of Notes to Consolidated Financial Statements for a discussion of the items in *income (loss) from discontinued operations.*

Nine months ended September 30, 2008 vs. nine months ended September 30, 2007

The increase in *revenues* is primarily due to higher production revenues at Exploration & Production resulting from both higher net realized average prices and increased production volumes sold. Midstream also experienced higher olefin production revenues primarily due to higher prices and volumes as well as increased NGL, olefin and crude marketing and NGL production revenues all due to higher prices, partially offset by lower volumes. In addition, *revenues* increased due to the favorable change in unrealized mark-to-market revenues at Gas Marketing Services primarily as a result of reduced losses in 2008 from legacy derivative contracts that are no longer outstanding.

The increase in *costs and operating expenses* is primarily due to increased NGL, olefin, and crude marketing purchases and increased costs associated with our olefin and NGL production businesses at Midstream. Higher depreciation, depletion and amortization, increased operating taxes and higher lease operating expenses at Exploration & Production also contributed to our increased expenses.

The increase in *SG&A* includes the impact of higher staffing and compensation at our Exploration & Production and Midstream segments in support of increased operational activities. The increase also includes $11 million in bad debt expense primarily at Exploration & Production.

Other income — net within *operating income* in 2008 includes a gain of $148 million on the sale of a contractual right to a production payment on certain future international hydrocarbon production at Exploration & Production, $20 million of net gains on foreign currency exchanges at Midstream, and a gain of $10 million on the sale of certain south Texas assets at Gas Pipeline. These items are partially offset by $21 million higher project development costs at Gas Pipeline and a $14 million impairment of certain natural gas producing properties at Exploration & Production.

Other income — net within *operating income* in 2007 includes income of $18 million associated with payments received for a terminated firm transportation agreement on Gas Pipeline's Grays Harbor lateral and income of $17 million from a change in estimate related to a regulatory liability at Northwest Pipeline.

The increase in *operating income* reflects increased net realized average prices, continued strong natural gas production growth and a gain of $148 million on the sale of a contractual right to a production payment at Exploration & Production, partially offset by higher operating costs. The increase also reflects reduced losses in 2008 from legacy derivative contracts that are no longer outstanding at Gas Marketing Services and continued favorable commodity price margins at Midstream, partially offset by higher operating costs.

Interest accrued — net decreased primarily due to increased capitalized interest resulting from an increased level of capital expenditures. Additionally, the decrease was impacted by lower interest rates on debt issuances that occurred late in the fourth quarter 2007 and in the first half of 2008 for which the proceeds were primarily used to retire existing debt bearing higher interest rates. While our overall debt balances have been relatively comparable, the net effect of these retirements and issuances has resulted in lower rates.

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Management's Discussion and Analysis (Continued)

The decrease in investing income is primarily due to $47 million of decreased interest income largely due to lower average interest rates in 2008 compared to 2007, partially offset by an increase in equity earnings of $31 million, primarily at Midstream.

Minority interest in income of consolidated subsidiaries increased primarily due to the growth in the minority interest holdings of Williams Partners L.P. and Williams Pipeline Partners L.P.

Provision for income taxes increased primarily due to higher pre-tax income. See Note 5 of Notes to Consolidated Financial Statements for a discussion of the effective tax rates compared to the federal statutory rate for both periods.

See Note 3 of Notes to Consolidated Financial Statements for a discussion of the items in *income (loss) from discontinued operations.*

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Management's Discussion and Analysis (Continued)

Results of Operations — Segments

Exploration & Production

Overview of Nine Months Ended September 30, 2008

During the first nine months of 2008, we continued our development drilling program in our growth basins. Accordingly, we:

- Benefited from increased domestic net realized average prices, which increased by approximately 42 percent compared to the first nine months of 2007. The domestic net realized average price for the first nine months of 2008 was $7.22 per thousand cubic feet of gas equivalent (Mcfe) compared to $5.09 per Mcfe in 2007. Net realized average prices include market prices, net of fuel and shrink and hedge positions, less gathering and transportation expenses.

- Increased average daily domestic production levels by approximately 21 percent compared to the first nine months of 2007. The average daily domestic production for the first nine months of 2008 was approximately 1,073 million cubic feet of gas equivalent (MMcfe) compared to 890 MMcfe in 2007. The increased production is primarily due to increased development within the Piceance, Powder River, and Fort Worth basins.

- Increased capital expenditures for domestic drilling, development, and acquisition activity in the first nine months of 2008 by $699 million compared to 2007. Capital expenditures for 2008 include acquisitions in the Piceance and Fort Worth basins discussed in *Significant events* below.

The benefits of higher net realized average prices and higher production volumes were partially offset by increased operating costs. The increase in operating costs was primarily due to increased production volumes and higher well service and lease service costs. In addition, higher production volumes coupled with higher capitalized drilling costs increased depletion, depreciation, and amortization expense.

Significant events

In January 2008, we sold a contractual right to a production payment on certain future international hydrocarbon production for $148 million. In the first quarter of 2008, we received $118 million in cash, with the remainder placed in escrow subject to certain post-closing conditions and adjustments. We recognized a pre-tax gain of $118 million in the first quarter of 2008 related to the initial cash received. In the second quarter of 2008, the remaining cash was received from escrow and recognized as income. As a result of the contract termination, we have no further interests associated with the crude oil concession, which is located in Peru. We had obtained these interests through our acquisition of Barrett Resources Corporation in 2001.

In May 2008, we acquired certain undeveloped leasehold acreage, producing properties and gathering facilities in the Piceance basin for $285 million. In July 2008, a third party exercised its contractual option to purchase, on the same terms and conditions, an interest in a portion of the acquired assets for $71 million. We received this $71 million in October 2008.

In September 2008, we increased our position in the Fort Worth basin by acquiring certain undeveloped leasehold acreage and producing properties for $147 million subject to post-closing adjustments. This acquisition is consistent with our growth strategy of leveraging our horizontal drilling expertise by acquiring and developing low-risk properties. The change in purchase price from the $166 million announced in July 2008 relates to the ongoing process of finalizing title work on a small portion of the acquisition package.

Outlook for the Remainder of 2008

Our expectations for the remainder of the year include:

- Maintaining our development drilling program in the Piceance, Powder River, San Juan, Fort Worth and Arkoma basins through our remaining planned capital expenditures projected between $450 million and $550 million.

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Management's Discussion and Analysis (Continued)

- Continuing toward our average daily domestic production level goal of 10 to 20 percent growth compared to 2007.

Risks to achieving our expectations include unfavorable natural gas market price movements which are impacted by numerous factors, including weather conditions, domestic natural gas production and consumption, and rising concerns about the recent volatility in the global economy and the related impact on natural gas prices. Also, achievement of expectations can be affected by costs of services associated with drilling.

In addition, changes in laws and regulations may impact our development drilling program. The Colorado Oil & Gas Conservation Commission (COGCC) has proposed rules that could alter our drilling schedule and increase our costs of permitting and environmental compliance. We continue to actively monitor the situation and provide input to the COGCC staff responsible for rulemaking. The final rules could become effective as early as April 2009.

Declining Natural Gas Prices

As a result of the recent market events and the recent decline in natural gas prices, we plan to deploy fewer drilling rigs in 2009 compared to 2008. This will reduce capital expenditures and the number of wells drilled in 2009 compared to 2008. However, we still expect approximately 8 to 10 percent production growth in 2009 compared to 2008. We continue to utilize certain derivative instruments to hedge our cash flows from the sales of natural gas production.

Hedging Strategy

To manage the commodity price risk and volatility of owning producing gas properties, we enter into derivative forward sales contracts that fix the sales price relating to a portion of our future production using NYMEX and basis fixed-price contracts and collar agreements.

For the remainder of 2008 and total year 2009, we have the following agreements and contracts for our daily domestic production, shown at weighted average volumes and basin-level weighted average prices:

	Remainder of 2008		2009	
	Volume (MMcf/d)	Price ($/Mcf) Floor-Ceiling for Collars	Volume (MMcf/d)	Price ($/Mcf) Floor-Ceiling for Collars
Collar agreements — Rockies	160	$6.08 – $9.04	150	$6.11 – $9.04
Collar agreements — San Juan	220	$6.37 – $9.00	245	$6.58 – $9.62
Collar agreements — Mid-Continent	80	$7.02 – $9.77	95	$7.08 – $9.73
NYMEX and basis fixed-price	70	$4.06	106	$3.67

The following is a summary of our agreements and contracts for daily production for the three and nine months ended September 30, 2008 and 2007:

	2008		2007	
	Volume (MMcf/d)	Price ($/Mcf) Floor-Ceiling for Collars	Volume (MMcf/d)	Price ($/Mcf) Floor-Ceiling for Collars
Third Quarter:				
Collar agreements — NYMEX	—	—	15	$6.50 – $8.25
Collar agreements — Rockies	160	$6.08 – $9.04	50	$5.65 – $7.45
Collar agreements — San Juan	220	$6.37 – $9.00	130	$5.98 – $9.63
Collar agreements — Mid-Continent	80	$7.02 – $9.77	78	$6.82 – $10.73
NYMEX and basis fixed-price	70	$3.90	171	$3.75
Year-to-Date:				
Collar agreements — NYMEX	—	—	15	$6.50 – $8.25
Collar agreements — Rockies	173	$6.18 – $9.18	50	$5.65 – $7.45
Collar agreements — San Juan	196	$6.34 – $8.94	130	$5.98 – $9.63
Collar agreements — Mid-Continent	57	$7.03 – $9.71	76	$6.82 – $10.78
NYMEX and basis fixed-price	70	$3.94	172	$3.82

Period-Over-Period Results

	Three months ended September 30,		Nine months ended September 30,	
	2008	2007	2008	2007

	(Millions)		(Millions)	
Segment revenues	$ 883	$ 499	$ 2,607	$ 1,521
Segment profit	$ 361	$ 169	$ 1,287	$ 566

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Management's Discussion and Analysis (Continued)

Three months ended September 30, 2008 vs. three months ended September 30, 2007

Total *segment revenues* increased $384 million, or 77 percent, primarily due to the following:

- $316 million, or 79 percent, increase in domestic production revenues reflecting $243 million associated with a 52 percent increase in net realized average prices and $73 million associated with a 18 percent increase in production volumes sold. The impact of hedge positions on increased net realized average prices includes the effect of fewer volumes hedged by fixed-price contracts. The increase in production volumes reflects an increase in the number of producing wells primarily from the Piceance, Powder River, and Fort Worth basins. Production revenues in 2008 and 2007 include approximately $32 million and $15 million, respectively, related to natural gas liquids (NGL) and approximately $25 million and $11 million, respectively, related to condensate;

- $53 million increase in revenues for gas management activities related to gas sold on behalf of certain outside parties, which is offset by a similar increase in *segment costs and expenses*. This increase is primarily due to increases in natural gas prices and volumes sold;

- $10 million increase in unrealized gains from hedge ineffectiveness.

Total *segment costs and expenses* increased $187 million, primarily due to the following:

- $53 million increase in expenses for gas management activities related to gas purchased on behalf of certain outside parties, which is offset by a similar increase in *segment revenues*;

- $48 million higher depreciation, depletion and amortization expense primarily due to higher production volumes and increased capitalized drilling costs;

- $35 million higher operating taxes primarily due to higher average market prices and higher production volumes sold;

- $18 million higher lease operating expenses from the increased number of producing wells, primarily within the Piceance, Powder River, and Fort Worth basins, combined with higher well and lease service expenses and facility expenses;

- $14 million higher SG&A expenses primarily due to increased staffing in support of increased drilling and operational activity, including higher compensation. The higher SG&A expenses also include an increase of $4 million in bad debt expense;

- $14 million impairment in 2008 due to recent drilling results in the Caney Shale in the Arkoma basin.

The $192 million increase in s*egment profit* is primarily due to the 52 percent increase in domestic net realized average prices and the 18 percent increase in domestic production volumes sold, partially offset by the increases in *segment costs and expenses*.

Nine months ended September 30, 2008 vs. nine months ended September 30, 2007

Total *segment revenues* increased approximately $1.1 billion, or 71 percent, primarily due to the following:

- $897 million, or 71 percent, increase in domestic production revenues reflecting $633 million associated with a 42 percent increase in net realized average prices and $264 million associated with a 21 percent increase in production volumes sold. The impact of hedge positions on increased net realized average prices includes the

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effect of fewer volumes hedged by fixed-price contracts. The increase in production volumes reflects an increase in the number of producing wells primarily from the Piceance, Powder River, and Fort Worth basins. Production revenues in 2008 and 2007 include approximately $75 million and $34 million, respectively, related to natural gas liquids and approximately $60 million and $26 million, respectively, related to condensate;

- $168 million increase in revenues for gas management activities related to gas sold on behalf of certain outside parties, which is offset by a similar increase in *segment costs and expenses*. This increase is primarily due to increases in natural gas prices and volumes sold.

Total *segment costs and expenses* increased $359 million, primarily due to the following:

- $168 million increase in expenses for gas management activities related to gas purchased on behalf of certain outside parties, which is offset by a similar increase in *segment revenues*;
- $151 million higher depreciation, depletion and amortization expense primarily due to higher production volumes and increased capitalized drilling costs;
- $84 million higher operating taxes primarily due to higher average market prices and higher production volumes sold;
- $46 million higher lease operating expenses from the increased number of producing wells primarily within the Piceance, Powder River, and Fort Worth basins combined with higher well and lease service expenses and facility expenses;
- $27 million higher SG&A expenses primarily due to increased staffing in support of increased drilling and operational activity, including higher compensation. The higher SG&A expenses also include an increase of $9 million in bad debt expense;
- $14 million impairment in 2008 due to recent drilling results in the Caney Shale in the Arkoma basin.

These increases are partially offset by the $148 million gain associated with the previously discussed sale of our Peru interests in 2008.

The $721 million increase in s*egment profit* is primarily due to the 42 percent increase in domestic net realized average prices, the 21 percent increase in domestic production volumes sold, and the $148 million gain associated with the sale of our Peru interests, partially offset by the increases in *segment costs and expenses*.

Gas Pipeline

Overview of Nine Months Ended September 30, 2008

Gas Pipeline master limited partnership

In January 2008, Williams Pipeline Partners L.P. completed its initial public offering of 16.25 million common units at a price of $20 per unit. In February 2008, the underwriters exercised their right to purchase an additional 1.65 million common units at the same price. The initial asset of the partnership is a 35 percent interest in Northwest Pipeline GP. Upon completion of these transactions, we now own approximately 47.7 percent of the interests in Williams Pipeline Partners L.P., including the interests of the general partner, which is wholly owned by us, and incentive distribution rights. In accordance with EITF Issue No. 04-5, we consolidate Williams Pipeline Partners L.P. within our Gas Pipeline segment due to our control through the general partner. (See Note 2 of Notes to Consolidated Financial Statements.) Gas Pipeline's segment profit includes 100 percent of Williams Pipeline Partners L.P.'s segment profit, with the minority interest's share presented below segment profit.

Status of rate case

During 2006, Transco filed a general rate case with the FERC for increases in rates. The new rates were effective, subject to refund, on March 1, 2007. On November 28, 2007, Transco filed a formal stipulation and agreement with the FERC resolving all substantive issues in their pending 2006 rate case. On March 7, 2008, the FERC approved the agreement without modification. The agreement became effective June 1, 2008 and required refunds were issued in July 2008.

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Management's Discussion and Analysis (Continued)

Gulfstream Phase III expansion project

In June 2007, our equity method investee, Gulfstream Natural Gas System, L.L.C. (Gulfstream), received FERC approval to extend its existing pipeline approximately 34 miles within Florida. Construction began in April 2008 and it was placed into service in September 2008. The extension fully subscribed the remaining 345 thousand dekatherms per day (Mdt/d) of firm capacity on the existing pipeline. Gulfstream's estimated cost of this project is $122 million.

Hurricane Ike

In September 2008, Hurricane Ike impacted several onshore and offshore facilities on Transco's interstate natural gas pipeline system resulting in varying degrees of damage. However, Transco has continued to meet its customer commitments while running at lower-than-normal volumes. We expect the majority of associated costs will be recoverable through insurance, with the remainder recoverable through Transco's rates.

Outlook for the Remainder of 2008

Gulfstream Phase IV expansion project

In September 2007, Gulfstream received FERC approval to construct 17.8 miles of 20-inch pipeline and to install a new compressor facility. Construction began in December 2007. The pipeline expansion was placed into service in October 2008, and the compressor facility is expected to be placed into service in January 2009. The expansion will increase capacity by 155 Mdt/d. Gulfstream's estimated cost of this project is $176 million.

Sentinel expansion project

In December 2007, we filed an application with the FERC to construct an expansion in the northeast United States. The cost of the project is estimated to be up to $200 million. The expansion will increase capacity by 142 Mdt/d and is expected to be placed into service in two phases, occurring in November 2008 and November 2009.

Period-Over-Period Results

	Three months ended September 30,		Nine months ended September 30,	
	2008	2007	2008	2007
	(Millions)		(Millions)	
Segment revenues	$ 407	$ 392	$ 1,226	$ 1,178
Segment profit	$ 173	$ 183	$ 532	$ 513

Three months ended September 30, 2008 vs. three months ended September 30, 2007

Segment revenues increased $15 million, or 4 percent, due primarily to $22 million higher revenues from transportation imbalance settlements (offset in *costs and operating expenses*) and a $7 million increase in transportation revenue attributable to expansion projects that Transco placed into service in the fourth quarter of 2007. Partially offsetting these increases is a $13 million decrease in revenues associated with a 2007 sale of excess inventory gas (offset in *costs and operating expenses*).

Costs and operating expenses increased $7 million, or 4 percent, due primarily to a $22 million increase in costs of transportation imbalance settlements (offset in *segment revenues*) partially offset by a $13 million decrease associated with a 2007 sale of excess inventory gas (offset in *segment revenues*).

Other income — net changed unfavorably by $13 million primarily due to the absence in 2008 of $12 million of income recognized in the third quarter of 2007 associated with a payment received for a terminated firm transportation agreement on Northwest Pipeline's Grays Harbor lateral and $12 million higher project development costs in 2008. Partially offsetting these unfavorable changes is a $10 million gain on the sale of certain south Texas assets in 2008 by Transco.

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Management's Discussion and Analysis (Continued)

The $10 million, or 5 percent, decrease in *segment profit* is due to the unfavorable change in *other income — net* and a $4 million charge associated with a third-quarter 2008 pipeline rupture, partially offset by the increase in transportation revenue attributable to expansion projects.

Nine months ended September 30, 2008 vs. nine months ended September 30, 2007

Segment revenues increased $48 million, or 4 percent, due primarily to a $56 million increase in transportation revenues resulting primarily from Transco's new rates, which were effective March 2007, and expansion projects that Transco placed into service in the fourth quarter of 2007. In addition, *segment revenues* increased $31 million due to transportation imbalance settlements (offset in *costs and operating expenses*). Partially offsetting these increases is a $37 million decrease associated with a 2007 sale of excess inventory gas (offset in *costs and operating expenses*).

Costs and operating expenses decreased $4 million, or 1 percent, due primarily to a $37 million decrease associated with a 2007 sale of excess inventory gas (offset in *segment revenues*). The decrease is substantially offset by an increase in costs of $31 million associated with transportation imbalance settlements (offset in *segment revenues*).

Other income — net changed unfavorably by $31 million due primarily to the absence in 2008 of $18 million of income recognized in 2007 associated with payments received for a terminated firm transportation agreement on Northwest Pipeline's Grays Harbor lateral and the absence in 2008 of $17 million of income recorded in 2007 for a change in estimate related to a regulatory liability at Northwest Pipeline. In addition, project development costs were $21 million higher in 2008. Partially offsetting these unfavorable changes is a $10 million gain on the sale of certain south Texas assets by Transco in 2008 and a second-quarter 2008 gain of $9 million on the sale of excess inventory gas.

The $19 million, or 4 percent, increase in *segment profit* is due primarily to the increase in transportation revenue, partially offset by the unfavorable change in *other income — net* and a $4 million charge associated with a third-quarter 2008 pipeline rupture.

Midstream Gas & Liquids

Overview of Nine Months Ended September 30, 2008

Midstream's ongoing strategy is to safely and reliably operate large-scale midstream infrastructure where our assets can be fully utilized and drive low per-unit costs. We focus on consistently attracting new business by providing highly reliable service to our customers.

Significant events during 2008 include the following:

Continued favorable commodity price margins

During the first three quarters of 2008, strong per-unit NGL margins driven by higher crude prices, which generally correlate to strong NGL prices, in relationship to natural gas prices have contributed significantly to our realized margins. The geographic diversification of Midstream assets also contributed to realized per-unit margins that were generally greater than that of the industry benchmarks for gas processed in the Henry Hub area and fractionated and sold at Mont Belvieu. Our average realized NGL per-unit margin at our processing plants during the three and nine months ended September 30, 2008 was 74 cents and 62 cents per gallon (cpg), a 19 percent and 35 percent increase over the same periods in 2007. Our NGL per-unit margin also increased during the third quarter of 2008 from the previous quarter due to higher NGL prices and a change in the mix of NGL products sold, partially offset by higher gas prices. Due to third-party NGL pipeline capacity restrictions during the third quarter of 2008, we had to reduce our recoveries of ethane, which typically has lower per-unit margins than non-ethane NGLs. If we had been able to produce the same mix of ethane and non-ethane NGLs during the third quarter of 2008 as we generally have in prior quarters, the increase in the average per-unit margin would have been lower. NGL margins have exceeded our rolling five-year average for the last six quarters, in spite of strong NGL margins over the last year that have significantly increased our rolling five-year average from approximately 22 cpg at the end of the third quarter of 2007 to 34 cpg at the end of the third quarter of 2008. NGL margins are defined as NGL revenues less BTU replacement cost, plant fuel, transportation and fractionation expense and include the impact of our hedging activities, which are discussed in *Outlook for the Remainder of 2008.*

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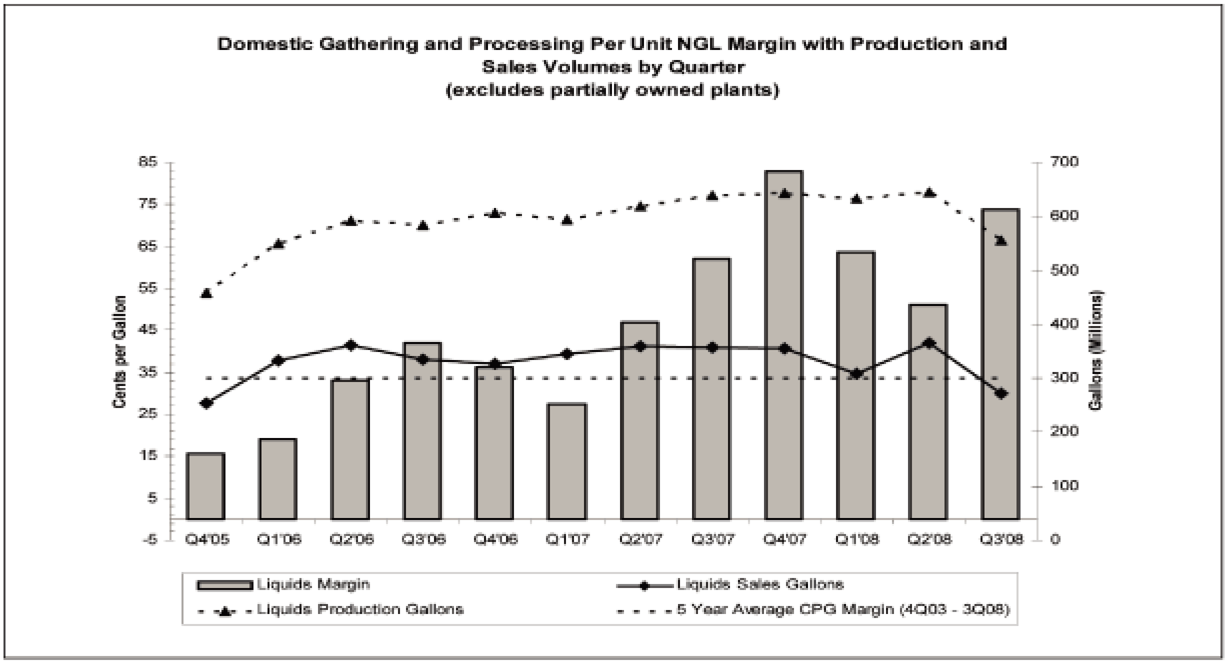
Management's Discussion and Analysis (Continued)



NGL sales volumes constrained

Primarily during the third quarter of 2008, we experienced restrictions on the volume of NGLs we could deliver to third-party NGL pipelines in our West region. These restrictions were caused by a lack of third-party NGL pipeline transportation capacity which resulted in us lowering our ethane recoveries to accommodate these restrictions. Beginning early in the fourth quarter of 2008, these restrictions were alleviated as we were able to deliver NGL volumes from one of our Wyoming plants into the new Overland Pass NGL pipeline. We expect the remaining NGL volumes from our Wyoming plants to begin flowing into Overland Pass later in the fourth quarter of 2008.

Hurricanes Gustav and Ike

As a result of Hurricanes Gustav and Ike in September 2008, not only did our Gulf Coast region facilities experience reduced volumes and damage, but our West region was also negatively impacted. We estimate that our segment profit for third-quarter 2008 was decreased by approximately $50 million to $65 million due to downtime and charges for repairs and property insurance deductibles associated with Hurricanes Gustav and Ike. We also estimate that fourth-quarter 2008 segment profit will be reduced by $10 million to $20 million due to downtime and reduced volumes associated with the hurricanes. Other than the Cameron Meadows natural gas processing plant and the Discovery offshore gathering system, our major gathering and processing assets in the Gulf of Mexico returned to full operations by the end of the third quarter. However, certain assets continue to run at reduced volumes as producers work to restore their operations to normal levels. The Cameron Meadows plant sustained significant damage from Hurricane Ike. Operations are suspended while we evaluate the timing and extent of the required repairs. The Discovery offshore system, which we operate and own a 60 percent equity interest in, also sustained hurricane damage and is not accepting offshore gas from producers while repairs are being made. The mainline is scheduled to be repaired and returned to service by early December. However, due to further damage assessments, the repair schedule for a lateral is not yet finalized. In the West region, we had to store NGL inventories due to the hurricane-related suspension of operations at a third-party fractionation facility at Mont Belvieu, Texas. We expect to sell most of this excess inventory in the fourth quarter of 2008 and in early 2009.

Major expansion efforts in growth areas

Consistent with our strategy, we continued construction on the following large-scale assets in growth basins.

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Management's Discussion and Analysis (Continued)

Gulf Coast region

The total estimated cost of our major expansion projects in the Gulf Coast region is approximately $810 million, of which approximately $235 million remains to be spent.

- In the deepwater of the Gulf of Mexico, we have completed construction of 37-mile extensions of both of our oil and gas pipelines from our Devils Tower spar to the Blind Faith prospect located in Mississippi Canyon in the eastern deepwater of the Gulf of Mexico. The pipelines have been commissioned and are ready for production to begin flowing. We expect this project to begin contributing to our segment profit in the fourth quarter of 2008.
- We continue construction activities on the Perdido Norte project, which will include an expansion of our Markham gas processing facility and oil and gas lines that will expand the scale of our existing infrastructure in the western deepwater of the Gulf of Mexico. We expect this project to begin contributing to our segment profit at the end of 2009.

West region

We expect to spend approximately $590 million in total on our major expansion projects in the West region, of which approximately $410 million remains to be spent. Our two major expansion projects include the new Willow Creek facility and additional capacity at our Echo Springs facility.

- The new Willow Creek facility is a 450 MMcf/d natural gas processing plant in western Colorado's Piceance basin. Major equipment purchases, vessel fabrication and site clearing and grading are well under way. We expect the new Willow Creek facility to recover 25,000 barrels per day of NGLs at startup in the latter part of 2009.
- In May 2008, we announced that we plan to significantly increase the processing and NGL production capacities at our Echo Springs natural gas processing plant in Wyoming. The addition of a fourth cryogenic processing train will add approximately 350 MMcf/d of processing capacity and 30,000 barrels per day of NGL production capacity, roughly doubling Echo Spring's volumes in both cases. We expect to begin construction on the fourth train at Echo Springs during the second half of 2009 and to bring the additional capacity online during late 2010, subject to all applicable permitting.

Williams Partners L.P.

We currently own approximately 23.6 percent of Williams Partners L.P., including the interests of the general partner, which is wholly owned by us, and incentive distribution rights. Considering the presumption of control of the general partner in accordance with EITF Issue No. 04-5, we consolidate Williams Partners L.P. within the Midstream segment. (See Note 2 of Notes to Consolidated Financial Statements.) Midstream's segment profit includes 100 percent of Williams Partners L.P.'s segment profit, with the minority interest's share presented below segment profit. The debt and equity issued by Williams Partners L.P. to third parties is reported as a component of our consolidated debt balance and minority interest balance, respectively.

Outlook for the Remainder of 2008

The following factors could impact our business in 2008.

- We expect our per-unit NGL margins to continue to exceed our rolling five-year average, although as evidenced by recent events, crude and natural gas prices are highly volatile. We expect lower per-unit margins in the fourth quarter of 2008 compared to the third quarter of 2008 as NGL prices, especially ethane, decline along with crude price declines. We anticipate periods when it will not be economical to recover ethane in the Gulf Coast region, which will reduce our margins. However, we expect continued favorable gas price differentials in the Rocky Mountain area to mitigate per-unit margin declines in the West region. Although NGL products are currently the preferred feedstock for ethylene and propylene production, which are the building blocks of polyethylene or plastics, due to the relative price of alternative crude-based feedstocks, forecasted domestic and global demand for polyethylene has weakened with the recent instability in the economy.

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Management's Discussion and Analysis (Continued)

- We expect a reduction in our segment profit in the fourth quarter of 2008 due to reduced volumes associated with the hurricanes. While we expect business interruption insurance to largely mitigate any losses associated with outages beyond 60 days, the timing to resolve these claims is uncertain. In addition, damage to third-party facilities has idled two of our smaller offshore gathering systems in the Gulf Coast region. If these third-party producers do not or are unable to restore their operations, our assets may become impaired.

- We expect significant savings in certain NGL transportation costs in the West region, which are a component of our per-unit NGL margin, as we transition from our current shipping arrangement to transportation on the Overland Pass pipeline. NGL volumes from one of our Wyoming plants began to flow into the Overland Pass pipeline early in the fourth quarter of 2008, and we expect the remaining NGL volumes from the other plant to begin flowing by the end of this year. We have agreed to dedicate our equity NGL volumes from our two Wyoming plants for transport under a long-term shipping agreement with Overland Pass Pipeline Company, LLC. We currently have a 1 percent interest in Overland Pass Pipeline Company, LLC and have the option to increase our ownership to 50 percent and become the operator within two years of the pipeline becoming operational.

- We entered into various financial hedging contracts during December 2007, and January and February 2008. Of our forecasted domestic NGL sales for the fourth quarter of 2008, approximately 22 percent have been hedged with collar agreements at an expected weighted average sales price that approximates our average 2007 domestic NGL sales price and approximately four percent have been hedged with fixed-price swap contracts. The natural gas shrink requirements associated with the sales under the fixed-price swap contracts have also been hedged through Gas Marketing Services with physical gas purchase contracts, thus effectively hedging the margin on the volumes associated with fixed price swap contracts at a level approximating our 2007 average per-unit margins.

- Based on the cost advantage of our propylene and ethylene production processes compared to other production processes which use crude-based feedstocks and our increased ownership interest in the Geismar olefins facility effective July 2007, we anticipate results from our olefins business for the 2008 year to be above 2007 levels. However, margins in our olefins business are highly dependent upon continued demand within the global economy and our cost advantage diminishes as crude prices decline. The significant slow down in domestic and global economies could further reduce the demand for the petrochemical products we produce in both Canada and the United States.

- Certain of our gas processing contracts contain provisions that allow customers to periodically elect processing services on either a fee-basis or a keep-whole or percent-of-liquids basis. Such elections may affect our future revenues. Fee-based revenues generally reduce our exposure to commodity price risks, but may also reduce our profitability in high margin environments.

- We expect continued expansion of our gathering and processing systems in our Gulf Coast and West regions to keep pace with increased demand for our services. As we pursue these activities, we expect our operating expenses to increase.

- Final resolution of our negotiations with the Jicarilla Apache Nation (JAN) concerning our gathering system assets located on JAN-owned land will impact our future operating results. During the third quarter of 2008, negotiations with the JAN, which have been ongoing since the expiration of our right-of-way agreement with them on December 31, 2006, expanded from an asset sale to discussions of other alternative arrangements. While the ultimate outcome is unknown at this time, the alternative arrangements could allow us to retain revenue associated with these gathering system assets, although it may also increase annual operating costs.

Period-Over-Period Results

	Three months ended September 30,		Nine months ended September 30,	
	2008	2007	2008	2007
	(Millions)		(Millions)	
Segment revenues	$ 1,436	$ 1,360	$ 4,747	$ 3,605
Segment profit (loss)				
Domestic gathering & processing	225	251	661	586
Venezuela	30	22	84	78
Other	23	49	139	103
Indirect general and administrative expense	(24)	(22)	(74)	(62)
Total	$ 254	$ 300	$ 810	$ 705

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Management's Discussion and Analysis (Continued)

In order to provide additional clarity, our management's discussion and analysis of operating results separately reflects the portion of general and administrative expense not allocated to an asset group as *indirect general and administrative expense*. These charges represent any overhead cost not directly attributable to one of the specific asset groups noted in this discussion.

Three months ended September 30, 2008 vs. three months ended September 30, 2007

The $76 million, or 6 percent, increase in *segment revenues* is largely due to:

- A $50 million increase in revenues associated with the production of NGLs due primarily to higher NGL prices, partially offset by lower volumes.
- A $31 million increase in revenues in our olefins production business due primarily to higher prices, partially offset by lower volumes.
- A $16 million increase in fee revenues due primarily to higher Venezuelan processing fee revenues and higher storage and fractionation fee revenues.

These increases are partially offset by a $24 million decrease in revenues from the marketing of NGLs, olefins and crude due primarily to lower NGL and crude volumes, partially offset by higher NGL and crude prices.

Segment costs and expenses increased $128 million, or 12 percent, primarily as a result of:

- A $72 million increase in costs associated with the production of NGLs due primarily to higher natural gas prices, partially offset by lower volumes.
- A $48 million increase in costs in our olefins production business due primarily to higher feedstock costs, partially offset by lower volumes.
- A $24 million increase in operating costs driven by higher repair costs and property insurance deductibles related to the hurricanes and higher depreciation.
- A $5 million increase in NGL, olefin and crude marketing purchases due primarily to higher NGL and crude prices and a $14 million write-down of NGL inventories to the lower of cost or market, partially offset by lower volumes.

These increases are partially offset by a $17 million favorable change consisting of $8 million in foreign exchange gains relating to the revaluation of current assets held in U.S. dollars within our Canadian operations, compared to $9 million in losses in 2007.

The $46 million, or 15 percent, decrease in Midstream's *segment profit* primarily reflects the previously described changes in *segment revenues* and *segment costs and expenses*. A more detailed analysis of the segment profit of certain Midstream operations is presented as follows.

Domestic gathering & processing

The $26 million decrease in *domestic gathering & processing segment profit* includes a $19 million decrease in the West region and a $7 million decrease in the Gulf Coast region.

The $19 million decrease in the West region's *segment profit* includes:

- A $26 million decrease in NGL margins due to significantly lower volumes and higher gas prices, partially offset by higher NGL prices. Due to the previously discussed lack of third-party NGL pipeline transportation capacity, it was necessary to lower our ethane recoveries to accommodate restrictions on the volume of NGLs we could deliver into the pipelines. In addition, as previously discussed, sales volumes were lower as the hurricane-related disruptions at a third-party fractionation facility at Mont Belvieu, Texas resulted in an NGL inventory build-up.

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- A $6 million involuntary conversion gain related to insurance recoveries in excess of the carrying value of our Ignacio plant. These insurance recoveries were used to rebuild the plant.

The $7 million decrease in the Gulf Coast region's *segment profit* includes:

- $5 million in operating costs related to hurricane repair and property insurance deductibles.
- A $4 million increase in NGL margins due to higher NGL prices, partially offset by higher gas prices and lower volumes. Volumes are lower due both to the hurricanes and natural declines in some fields, partially offset by new supplies connected in the deepwater.

Other

The significant components of the $26 million decrease in *segment profit* of our other operations include:

- $29 million in lower margins related to the marketing of NGLs and olefins due primarily to a $14 million charge relating to a lower of cost or market adjustment on NGL inventories and greater unfavorable changes in pricing while product was in transit during 2008 as compared to 2007.
- $17 million in lower margins in our olefins production business due primarily to lower volumes as a result of third-party operational issues that reduced off-gas supplies to our plant in Canada and higher feedstock prices, partially offset by higher olefin sales prices.

These decreases are partially offset by a $17 million favorable change consisting of $8 million in foreign exchange gains related to the revaluation of current assets held in U.S. dollars within our Canadian operations, compared to $9 million in losses in 2007.

Nine months ended September 30, 2008 vs. nine months ended September 30, 2007

The $1,142 million, or 32 percent, increase in *segment revenues* is largely due to:

- A $385 million increase in revenues in our olefins production business due primarily to higher prices and higher volumes sold associated with the increase of our ownership interest in the Geismar olefins facility effective July 2007.
- A $375 million increase in revenues from the marketing of NGLs, olefins and crude due primarily to higher NGL and crude prices, partially offset by lower volumes sold.
- A $328 million increase in revenues associated with the production of NGLs due primarily to higher NGL prices, partially offset by lower volumes.
- A $39 million increase in fee-based revenues due primarily to higher fee-based revenues in Venezuela and the West region.

Segment costs and expenses increased $1,068 million, or 36 percent, primarily as a result of:

- A $407 million increase in NGL, olefin and crude marketing purchases due primarily to higher NGL and crude prices, partially offset by lower volumes.
- A $347 million increase in costs in our olefins production business due to both higher feedstock prices and higher volumes produced associated with the increase of our ownership interest in the Geismar olefins facility effective July 2007.
- A $230 million increase in costs associated with the production of NGLs due primarily to higher natural gas prices.
- An $80 million increase in operating costs including higher employee costs, repair costs and property insurance deductibles related to the hurricanes, costs associated with the increase of our ownership interest in the Geismar olefins facility, depreciation and gas transportation expenses in the eastern Gulf of Mexico.

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Management's Discussion and Analysis (Continued)

- A $31 million favorable change consisting of $13 million in foreign exchange gains in the first nine months of 2008 related to the revaluation of current assets held in U.S. dollars within our Canadian operations, compared to $18 million in losses in the first nine months of 2007.

The $105 million, or 15 percent, increase in Midstream's *segment profit* reflects $31 million higher equity earnings and the previously described changes in *segment revenues* and *segment costs and expenses*. A more detailed analysis of the segment profit of certain Midstream operations is presented as follows.

Domestic gathering & processing

The $75 million increase in *domestic gathering & processing segment profit* includes a $35 million increase in the West region and a $40 million increase in the Gulf Coast region.

The $35 million increase in our West region's *segment profit* includes:

- A $33 million increase in NGL margins due to a significant increase in average per-unit NGL prices, partially offset by a significant increase in costs associated with the production of NGLs reflecting higher natural gas prices and lower volumes sold. The decrease in volumes sold is due primarily to forced reductions in ethane recoveries to accommodate restrictions in third-party NGL pipeline transportation capacity, an increase in inventory during the first quarter of 2008 caused by the transition from product sales at the plant to shipping volumes through a pipeline for sale downstream, an increase in inventory during the third quarter of 2008 related to previously discussed hurricane-related disruptions at a third-party fractionation facility, and lower equity volumes as processing agreements change from keep-whole to fee-based. These decreases were partially offset by a full year of production from the fifth train at our Opal processing plant, which began production in the first quarter of 2007.

- A $14 million increase in fee revenues due primarily to new lease revenues from Gas Pipeline for the Parachute lateral transferred to Midstream in December 2007.

- A $9 million involuntary conversion gain related to insurance recoveries in excess of the carrying value of our Ignacio plant. These insurance recoveries were used to rebuild the plant.

- A $29 million increase in operating costs driven by a $14 million increase in operations and maintenance expenses including higher employee costs and turbine and engine overhaul expenses, higher depreciation, and higher gathering fuel expense.

The $40 million increase in the Gulf Coast region's *segment profit* is primarily due to higher NGL margins, partially offset by higher operating costs and other expenses. The significant components of this increase include:

- NGL margins increased $65 million due to significantly higher NGL prices and slightly higher volumes, partially offset by a significant increase in costs associated with the production of NGLs reflecting higher natural gas prices. The volume increase is due primarily to connecting new supplies in the deepwater, offset by reduced volumes related to the hurricanes in the third quarter of 2008.

- Operating costs increased $19 million, including $5 million in hurricane repair and property insurance deductibles and $9 million higher gas transportation expenses in the eastern Gulf of Mexico.

Venezuela

Segment profit for our Venezuela assets increased $6 million. The increase is due primarily to $15 million higher fee revenues resulting from gas compression and injection efficiencies and higher gas reimbursement rates, partially offset by $8 million in lower currency exchange gains.

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Management's Discussion and Analysis (Continued)

Other

The significant components of the $36 million increase in *segment profit* of our other operations include:

- $38 million in higher margins in our olefins production business due primarily to higher propylene margins, higher ethylene volumes associated with the increase of our ownership interest in the Geismar olefins facility effective July 2007, and higher margins on NGL products produced in our Canadian olefins operations, partially offset by lower volumes at our plant in Canada as a result of third-party operational issues that reduced off-gas supplies.
- Higher equity earnings including $15 million higher Discovery Producer Services L.L.C. equity earnings and $12 million higher Aux Sable Liquids Products, L.P. equity earnings primarily due to favorable processing margins.
- A $31 million favorable change consisting of $13 million in foreign exchange gains in the first nine months of 2008 related to the revaluation of current assets held in U.S. dollars within our Canadian operations, compared to $18 million in losses in the first nine months of 2007.

These increases are partially offset by:

- $32 million in lower margins related to the marketing of NGLs and olefins due primarily to a $14 million charge relating to a lower of cost or market adjustment on NGL inventories and unfavorable changes in pricing while product was in transit during 2008 as compared to 2007.
- $35 million higher operating costs including higher costs associated with the increase of our ownership interest in the Geismar olefins facility effective July 2007 and $3 million in repair expense at our Geismar plant which was damaged in Hurricane Gustav.

Gas Marketing Services

Gas Marketing Services (Gas Marketing) primarily supports our natural gas businesses by providing marketing and risk management services, which include marketing and hedging the gas produced by Exploration & Production and procuring fuel and shrink gas and hedging natural gas liquids sales for Midstream. In addition, Gas Marketing manages various natural gas-related contracts such as transportation, storage, related hedges and proprietary trading positions, including certain legacy natural gas contracts and positions. Gas Marketing also provides similar services to third parties, such as producers.

Overview of Nine Months Ended September 30, 2008

Gas Marketing's improved operating results for the first nine months of 2008 compared to the first nine months of 2007 reflect a favorable change in unrealized mark-to-market gains (losses) on derivatives that are not designated as hedges for accounting purposes or do not qualify for hedge accounting. The favorable change was largely the result of reduced losses in 2008 from legacy derivative contracts that are no longer outstanding. Results for 2008 also include favorable price movements on derivative positions executed to hedge the anticipated withdrawals of natural gas from storage. These gains were partially offset by lower-of-cost-or-market adjustments to the carrying value of the natural gas inventories in storage.

Outlook for the Remainder of 2008

For the remainder of 2008, Gas Marketing will focus on providing services that support our natural gas businesses. Certain legacy natural gas contracts and positions from our former Power segment remain in the Gas Marketing segment. Gas Marketing's earnings may continue to reflect mark-to-market volatility from commodity-based derivatives that represent economic hedges but are not designated as hedges for accounting purposes or do not qualify for hedge accounting, primarily those contracts used to hedge the anticipated storage withdrawals.

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Management's Discussion and Analysis (Continued)

Period-Over-Period Results

	Three months ended September 30,		Nine months ended September 30,	
	2008	2007	2008	2007
	(Millions)		(Millions)	
Realized revenues	$ 1,687	$ 1,300	$ 5,363	$ 4,084
Net forward unrealized mark-to-market gains (losses)	29	(53)	13	(155)
Segment revenues	1,716	1,247	5,376	3,929
Costs and operating expenses	1,695	1,312	5,369	4,080
Gross margin	21	(65)	7	(151)
Selling, general and administrative expenses	4	2	15	9
Other expense — net	1	—	1	—
Segment profit (loss)	$ 16	$ (67)	$ (9)	$ (160)

Three months ended September 30, 2008 vs. three months ended September 30, 2007

Realized revenues represent (1) revenue from the sale of natural gas or completion of energy-related services and (2) gains and losses from the net financial settlement of derivative contracts. Realized revenues increased $387 million primarily due to an increase in physical natural gas revenue as a result of a 49 percent increase in average prices on physical natural gas sales and an increase in net financial settlements of derivative contracts. The increase is partially offset by a 15 percent decrease in natural gas sales volumes due to increased volumes injected into storage.

Net forward unrealized mark-to-market gains (losses) primarily represent changes in the fair values of certain derivative contracts with a future settlement or delivery date that are not designated as hedges for accounting purposes or do not qualify for hedge accounting. The favorable change of $82 million in unrealized mark-to-market revenues is primarily the result of favorable price movements on derivative positions primarily related to our natural gas storage activity.

The $383 million increase in *cost and operating expenses* is primarily due to a 52 percent increase in average prices on physical natural gas purchases. Partially offsetting this increase is a 14 percent decrease in third-party natural gas purchase volumes. The third quarter of 2008 includes a $24 million lower-of-cost-or-market adjustment to inventory, compared to $21 million in the third quarter of 2007.

The $83 million improvement in *segment profit (loss)* is primarily due to the previously described favorable change in unrealized mark-to-market revenues.

Nine months ended September 30, 2008 vs. nine months ended September 30, 2007

Realized revenues increased $1,279 million primarily due to an increase in physical natural gas revenue as a result of a 39 percent increase in average prices on physical natural gas sales and an increase in net financial settlements of derivative contracts. The increase is partially offset by a 7 percent decrease in natural gas sales volumes.

The favorable change of $168 million in unrealized mark-to-market revenues is primarily the result of reduced losses in 2008 from legacy derivative contracts that are no longer outstanding in addition to favorable price movements on derivative positions primarily related to our natural gas storage activity. This change also includes a $10 million favorable impact in 2008 due to considering our own nonperformance risk in estimating the fair value of our derivative liabilities in accordance with the implementation of SFAS 157. (See Note 10 of Notes to Consolidated Financial Statements.)

The $1,289 million increase in *cost and operating expenses* is primarily due to a 41 percent increase in average prices on physical natural gas purchases. Partially offsetting this increase is a 6 percent decrease in natural gas purchase volumes. Year-to-date 2008 includes a $32 million lower-of-cost-or-market adjustment to inventory, compared to a $25 million adjustment in the prior year.

The $151 million improvement in *segment profit (loss)* is primarily due to the previously described favorable change in unrealized mark-to-market revenues and the favorable impact of applying a credit reserve for nonperformance risk on our own derivative liabilities in accordance with the implementation of SFAS 157. These favorable changes were partially offset by a decrease in realized gross margin.

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Management's Discussion and Analysis (Continued)

Other

Period-Over-Period Results

	Three months ended September 30, 2008	Three months ended September 30, 2007	Nine months ended September 30, 2008	Nine months ended September 30, 2007
	(Millions)		(Millions)	
Segment revenues	$ 6	$ 7	$ 18	$ 20
Segment profit (loss)	$ (2)	$ —	$ (2)	$ —

The results of our Other segment are relatively comparable to the prior year.

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Management's Discussion and Analysis (Continued)

Energy Trading Activities

Fair Value of Trading and Nontrading Derivatives

The chart below reflects the fair value of derivatives held for trading purposes as of September 30, 2008. We have presented the fair value of assets and liabilities by the period in which they would be realized under their contractual terms and not as a result of a sale. We have reported the fair value of a portion of these derivatives in assets and liabilities of discontinued operations. (See Note 3 of Notes to Consolidated Financial Statements.)

Net Assets (Liabilities) — Trading
(Millions)

To be Realized in 1-12 Months (Year 1)	To be Realized in 13-36 Months (Years 2-3)	To be Realized in 37-60 Months (Years 4-5)	To be Realized in 61-120 Months (Years 6-10)	To be Realized in 121+ Months (Years 11+)	Net Fair Value
$(26)	$(21)	$—	$—	$—	$(47)

We are not materially engaged in trading activities. However, we hold a substantial portfolio of nontrading derivative contracts. Nontrading derivative contracts are those that hedge or could possibly hedge forecasted transactions on an economic basis. We have designated certain of these contracts as cash flow hedges of Exploration & Production's forecasted sales of natural gas production and Midstream's forecasted sales of natural gas liquids under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS 133). Of the total fair value of nontrading derivatives, SFAS 133 cash flow hedges had a net asset value of $119 million as of September 30, 2008. The chart below reflects the fair value of derivatives held for nontrading purposes as of September 30, 2008, for Gas Marketing Services, Exploration & Production, Midstream, and nontrading derivatives reported in assets and liabilities of discontinued operations.

Net Assets (Liabilities) — Nontrading
(Millions)

To be Realized in 1-12 Months (Year 1)	To be Realized in 13-36 Months (Years 2-3)	To be Realized in 37-60 Months (Years 4-5)	To be Realized in 61-120 Months (Years 6-10)	To be Realized in 121+ Months (Years 11+)	Net Fair Value
$149	$25	$1	$1	$—	$176

Counterparty Credit Considerations

We include an assessment of the risk of counterparty nonperformance in our estimate of fair value for all contracts. Such assessment considers (1) the credit rating of each counterparty as represented by public rating agencies such as Standard & Poor's and Moody's Investors Service, (2) the inherent default probabilities within these ratings, (3) the regulatory environment that the contract is subject to and (4) the terms of each individual contract.

Risks surrounding counterparty performance and credit could ultimately impact the amount and timing of expected cash flows. We continually assess this risk. We have credit protection within various agreements to call on additional collateral support if necessary. At September 30, 2008, we held collateral support, including letters of credit, of $54 million.

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Management's Discussion and Analysis (Continued)

The gross credit exposure from our derivative contracts, a portion of which is included in assets of discontinued operations (see Note 3 of Notes to Consolidated Financial Statements), as of September 30, 2008, is summarized below.

Counterparty Type	Investment Grade (a)	Total
	(Millions)	
Gas and electric utilities	$ 1	$ 3
Energy marketers and traders	175	1,238
Financial institutions	1,867	1,870
	$ 2,043	3,111
Credit reserves		(1)
Gross credit exposure from derivatives		$ 3,110

We assess our credit exposure on a net basis to reflect master netting agreements with certain counterparties. We offset our credit exposure to each counterparty with amounts we owe the counterparty under derivative contracts. The net credit exposure from our derivatives as of September 30, 2008, is summarized below.

Counterparty Type	Investment Grade (a)	Total
	(Millions)	
Gas and electric utilities	$ 1	$ 3
Energy marketers and traders	71	76
Financial institutions	360	360
	$ 432	439
Credit reserves		(1)
Net credit exposure from derivatives		$ 438

(a) We determine investment grade primarily using publicly available credit ratings. We include counterparties with a minimum Standard & Poor's rating of BBB- or Moody's Investors Service rating of Baa3 in investment grade.

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Management's Discussion and Analysis of Financial Condition

Outlook

We entered 2008 positioned for growth through disciplined investments in our natural gas business. Examples of this planned growth include:

- Exploration & Production will continue to maintain its development drilling program in the Piceance, Powder River, San Juan, Fort Worth, and Arkoma basins.
- Gas Pipeline will continue to expand its system to meet the demand of growth markets.
- Midstream will continue to pursue significant deepwater production commitments and expand capacity in the western United States.

We estimate capital and investment expenditures will total $3.375 billion to $3.575 billion in 2008, with $782 million to $982 million to be incurred over the remainder of the year. Of the total estimated 2008 capital expenditures, $2.35 billion to $2.45 billion is related to Exploration & Production. Also within the total estimated expenditures for 2008 is approximately $170 million to $200 million for compliance and maintenance-related projects at Gas Pipeline, including Clean Air Act compliance. Capital and investment expenditures are expected to range from $2.8 billion to $3.1 billion in 2009.

We believe we have, or have access to, the financial resources and liquidity necessary to meet future requirements for working capital, capital and investment expenditures and debt payments while maintaining a sufficient level of liquidity to reasonably protect against unforeseen circumstances requiring the use of funds. We also expect to maintain our investment grade status. We expect to maintain liquidity of at least $1 billion from cash and cash equivalents and unused revolving credit facilities. We maintain adequate liquidity to manage margin requirements related to significant movements in commodity prices, unplanned capital spending needs, near term scheduled debt payments, and litigation and other settlements. We expect to fund capital and investment expenditures, debt payments, dividends, and working capital requirements primarily through cash flow from operations, which is estimated to be between $3.1 billion and $3.3 billion in 2008, and cash and cash equivalents on hand as needed. Cash flow from operations is expected to range from $2.4 billion to $3.1 billion in 2009. We have also historically provided for additional funding needs through the issuance of debt and sales of units of Williams Partners L.P. and Williams Pipeline Partners L.P. However, as a result of credit market conditions at the time of this filing, these sources of funding are considered economically prohibitive and are unlikely to be utilized in this economic environment.

Potential risks associated with our planned levels of liquidity and the planned capital and investment expenditures discussed above include:

- The impact of the general economic downturn, including associated volatility and our ability to access capital markets (see Recent Market Events).
- Lower than expected levels of cash flow from operations due to commodity pricing volatility. To mitigate this exposure, both our Exploration & Production and Midstream segments utilize hedging programs to manage commodity price risk.
- Sensitivity of margin requirements associated with our marginable commodity contracts. As of September 30, 2008, we estimate our exposure to additional margin requirements through the remainder of 2008 to be no more than $26 million, using a statistical analysis at a 99 percent confidence level.
- Exposure associated with our efforts to resolve regulatory and litigation issues (see Note 12 of Notes to Consolidated Financial Statements).

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Management's Discussion and Analysis (Continued)

Liquidity

Our internal and external sources of liquidity include cash generated from our operations, bank financings, proceeds from the issuance of long-term debt and equity securities, and proceeds from asset sales. While most of our sources are available to us at the parent level, others are available to certain of our subsidiaries, including equity and debt issuances from Williams Partners L.P. and Williams Pipeline Partners L.P., our master limited partnerships. Our ability to raise funds in the capital markets will be impacted by our financial condition, interest rates, market conditions, and industry conditions.

Available Liquidity

		September 30, 2008 (Millions)
Cash and cash equivalents (1)	$	1,524
Available capacity under our four unsecured revolving and letter of credit facilities totaling $1.2 billion		963
Available capacity under our $1.5 billion unsecured revolving and letter of credit facility (2)		1,402
Available capacity under Williams Partners L.P.'s $450 million five-year senior unsecured credit facility (3)		188
	$	4,077

(1) *Cash and cash equivalents* includes $48 million of funds received from third parties as collateral. The obligation for these amounts is reported as *accrued liabilities* on the Consolidated Balance Sheet. Also included is $598 million of cash and cash equivalents that is being utilized by certain subsidiary and international operations. The remainder of our *cash and cash equivalents* is primarily held in government-backed instruments.

(2) Northwest Pipeline and Transco each have access to $400 million under this facility to the extent not utilized by us. We expect that the ability of both Northwest Pipeline and Transco to borrow under this facility is reduced by approximately $19 million each due to the bankruptcy of a participating bank. We also expect that our consolidated ability to borrow under this facility is reduced by a total of $70 million, including the reductions related to Northwest Pipeline and Transco. The available liquidity in the table above reflects this $70 million reduction. (See Note 9 of Notes to Consolidated Financial Statements.) The committed amounts of other participating banks under this agreement remain in effect and are not impacted by this reduction.

(3) This facility is only available to Williams Partners L.P. We expect that Williams Partners L.P.'s ability to borrow under this facility is reduced by $12 million. The available liquidity in the table above reflects this $12 million reduction. (See Note 9 of Notes to Consolidated Financial Statements.) The committed amounts of other participating banks under this agreement remain in effect and are not impacted by this reduction.

In addition to the above, Northwest Pipeline and Transco have shelf registration statements available for the issuance of up to $350 million aggregate principal amount of debt securities.

Williams Partners L.P. has a shelf registration statement available for the issuance of $1.17 billion aggregate principal amount of debt and limited partnership unit securities.

In addition, at the parent-company level, we have a shelf registration statement that allows us to issue publicly registered debt and equity securities.

Exploration & Production has an unsecured credit agreement with certain banks that serves to reduce our use of cash and other credit facilities for margin requirements related to our hedging activities as well as lower transaction fees. In June 2008, the agreement was extended through December 2013.

The above table does not include a $10 million auction rate security that is classified within *Investments* due to recent auction failures. We have the intent and ability to hold this investment grade security until we are able to realize its face value. We hold no other auction rate securities at September 30, 2008.

Credit ratings

Standard & Poor's rates our senior unsecured debt at BB+ and our corporate credit at BBB- with a stable ratings outlook. With respect to Standard & Poor's, a rating of "BBB" or above indicates an investment grade rating. A rating below "BBB" indicates that the security has significant speculative characteristics. A "BB" rating indicates that Standard & Poor's believes the issuer has the capacity to meet its financial commitment on the obligation, but adverse business conditions could lead to insufficient ability to meet financial commitments. Standard & Poor's may modify its ratings with a "+" or a "–" sign to show the obligor's relative standing within a major rating category.

Moody's Investors Service rates our senior unsecured debt at Baa3 with a stable ratings outlook. With respect to Moody's, a rating of "Baa" or above indicates an investment grade rating. A rating below "Baa" is considered to have speculative elements. The "1", "2" and "3" modifiers show the relative standing within a major category. A "1" indicates that an obligation ranks in the higher end of the broad rating category, "2" indicates a mid-range ranking, and "3" ranking at the lower end of the category.

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Management's Discussion and Analysis (Continued)

Fitch Ratings rates our senior unsecured debt at BBB- with a stable ratings outlook. With respect to Fitch, a rating of "BBB" or above indicates an investment grade rating. A rating below "BBB" is considered speculative grade. Fitch may add a "+" or a "–" sign to show the obligor's relative standing within a major rating category.

Sources (Uses) of Cash

	Nine months ended September 30, 2008	Nine months ended September 30, 2007
	(Millions)	
Net cash provided (used) by:		
Operating activities	$ 2,606	$ 1,677
Financing activities	(316)	(508)
Investing activities	(2,465)	(1,983)
Decrease in cash and cash equivalents	$ (175)	$ (814)

Operating activities

Our *net cash provided by operating activities* for the nine months ended September 30, 2008, increased from the same period in 2007 due primarily to the improvement in our operating results. Significant transactions impacting our *net cash provided by operating activities* in 2008 include:

- $128 million of cash received related to a favorable ruling from the Alaska Supreme Court (see Note 3 of Notes to Consolidated Financial Statements).
- $144 million of required refunds paid by Transco related to a general rate case with the FERC (see Results of Operations — Segments, Gas Pipeline).

Financing activities

Our *net cash used by financing activities* for the nine months ended September 30, 2008, decreased from the same period in 2007. Significant transactions include:

- $362 million of cash received in 2008 from the completion of the Williams Pipeline Partners L.P. initial public offering (see Note 2 of Notes to Consolidated Financial Statements).
- $474 million of cash payments for the repurchase of our common stock in 2008 (see Note 11 of Notes to Consolidated Financial Statements) compared to $234 million of our common stock repurchased in 2007.
- Net debt proceeds of $40 million in 2008 related primarily to $75 million of net cash received from debt transactions in the Gas Pipeline segment (see Note 9 of Notes to Consolidated Financial Statements). In 2007 we had net debt payments of $134 million.
- Quarterly dividends paid on common stock totaled $186 million in 2008 compared to $174 million in 2007.

Investing activities

Our *net cash used by investing activities* for the nine months ended September 30, 2008, increased from the same period in 2007. Significant transactions include:

- In 2008, capital expenditures totaled $2.6 billion and were largely related to Exploration & Production's drilling activity. This total includes Exploration & Production's acquisitions of certain interests in the Piceance and Fort Worth basins for $285 million and $147 million, respectively (see Results of Operations — Segments — Exploration & Production). In 2007, capital expenditures totaled $2.1 billion and were largely related to Exploration & Production's drilling activity, mostly in the Piceance basin.
- $148 million of cash received in 2008 from Exploration & Production's sale of a contractual right to a production payment (see Note 4 of Notes to Consolidated Financial Statements).

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Management's Discussion and Analysis (Continued)

- We purchased $105 million in investments in 2008, including $82 million related to our Gulfstream equity investment.
- We purchased $304 million and received $353 million from the sale of auction rate securities in 2007. These were utilized as a component of our overall cash management program.

Off-balance sheet financing arrangements and guarantees of debt

We have various guarantees which are disclosed in Note 12 of Notes to Consolidated Financial Statements. We do not believe these guarantees or the possible fulfillment of them will prevent us from meeting our liquidity needs.

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Quantitative and Qualitative Disclosures About Market Risk

Interest Rate Risk

Our interest rate risk exposure is primarily associated with our debt portfolio and has not materially changed during the first nine months of 2008. (See Note 9 of Notes to Consolidated Financial Statements.)

Commodity Price Risk

We are exposed to the impact of fluctuations in the market price of natural gas and natural gas liquids, as well as other market factors, such as market volatility and commodity price correlations. We are exposed to these risks in connection with our owned energy-related assets, our long-term energy-related contracts and our proprietary trading activities. We manage the risks associated with these market fluctuations using various derivatives and nonderivative energy-related contracts. The fair value of derivative contracts is subject to changes in energy-commodity market prices, the liquidity and volatility of the markets in which the contracts are transacted, and changes in interest rates. We measure the risk in our portfolios using a value-at-risk methodology to estimate the potential one-day loss from adverse changes in the fair value of the portfolios.

Value at risk requires a number of key assumptions and is not necessarily representative of actual losses in fair value that could be incurred from the portfolios. Our value-at-risk model uses a Monte Carlo method to simulate hypothetical movements in future market prices and assumes that, as a result of changes in commodity prices, there is a 95 percent probability that the one-day loss in fair value of the portfolios will not exceed the value at risk. The simulation method uses historical correlations and market forward prices and volatilities. In applying the value-at-risk methodology, we do not consider that the simulated hypothetical movements affect the positions or would cause any potential liquidity issues, nor do we consider that changing the portfolio in response to market conditions could affect market prices and could take longer than a one-day holding period to execute. While a one-day holding period has historically been the industry standard, a longer holding period could more accurately represent the true market risk given market liquidity and our own credit and liquidity constraints.

We segregate our derivative contracts into trading and nontrading contracts, as defined in the following paragraphs. We calculate value at risk separately for these two categories. Derivative contracts designated as normal purchases or sales under SFAS 133 and nonderivative energy contracts have been excluded from our estimation of value at risk.

Trading

Our trading portfolio consists of derivative contracts entered into for purposes other than economically hedging our commodity price-risk exposure. Our value at risk for contracts held for trading purposes was $.2 million at September 30, 2008, and $1 million at December 31, 2007.

Nontrading

Our nontrading portfolio consists of derivative contracts that hedge or could potentially hedge the price risk exposure from the following activities:

Segment	Commodity Price Risk Exposure
Exploration & Production	• Natural gas sales
Midstream	• Natural gas purchases • NGL sales
Gas Marketing Services	• Natural gas purchases and sales

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The value at risk for derivative contracts held for nontrading purposes was $36 million at September 30, 2008, and $24 million at December 31, 2007. Derivative contracts included in our assets and liabilities of discontinued operations are included in the nontrading portfolio, but these had a value at risk of zero for both periods.

Certain of the derivative contracts held for nontrading purposes are accounted for as cash flow hedges under SFAS 133. Though these contracts are included in our value-at-risk calculation, any changes in the fair value of the effective portion of these hedge contracts would generally not be reflected in earnings until the associated hedged item affects earnings.

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Item 4

Controls and Procedures

Evaluation of Disclosure Controls and Procedures

An evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act) (Disclosure Controls) was performed as of the end of the period covered by this report. This evaluation was performed under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that these Disclosure Controls are effective at a reasonable assurance level.

Our management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our Disclosure Controls or our internal controls over financial reporting (Internal Controls) will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. We monitor our Disclosure Controls and Internal Controls and make modifications as necessary; our intent in this regard is that the Disclosure Controls and the Internal Controls will be modified as systems change and conditions warrant.

Third-Quarter 2008 Changes in Internal Controls Over Financial Reporting

There have been no changes during the third-quarter of 2008 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

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PART II. OTHER INFORMATION

Item 1. Legal Proceedings

The information called for by this item is provided in Note 12 of Notes to Consolidated Financial Statements included under Part I, Item 1. Financial Statements of this report, which information is incorporated by reference into this item.

Item 1A. Risk Factors

Part I, Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2007, includes certain risk factors that could materially affect our business, financial condition or future results. Those Risk Factors have not materially changed except as set forth below:

Our businesses are subject to complex government regulations. The operation of our businesses might be adversely affected by changes in these regulations or in their interpretation or implementation, or the introduction of new laws or regulations applicable to our businesses or our customers.

Existing regulations might be revised or reinterpreted, new laws and regulations might be adopted or become applicable to us, our facilities or our customers, and future changes in laws and regulations might have a detrimental effect on our business. Specifically, the Colorado Oil & Gas Conservation Commission has proposed rules that could increase our costs of permitting and environmental compliance, may affect our ability to meet our anticipated drilling schedule and therefore may have a material effect on our results of operations. Over the past few years, certain restructured energy markets have experienced supply problems and price volatility. In some of these markets, proposals have been made by governmental agencies and other interested parties to re-regulate areas of these markets which have previously been deregulated. Various forms of market controls and limitations including price caps and bid caps have already been implemented and new controls and market restructuring proposals are in various stages of development, consideration and implementation. We cannot assure you that changes in market structure and regulation will not adversely affect our business and results of operations. We also cannot assure you that other proposals to re-regulate will not be made or that legislative or other attention to these restructured energy markets will not cause the deregulation process to be delayed or reversed or otherwise adversely affect our business and results of operations.

Recent events in the global credit markets have created a shortage in the availability of credit.

Global credit markets have recently experienced a shortage in overall liquidity and a resulting disruption in the availability of credit. While we cannot predict the occurrence of future disruptions or how long the current circumstances may continue, we believe cash on hand and cash provided by operating activities, as well as availability under our existing financing agreements will provide us with adequate liquidity for the foreseeable future. However, our ability to borrow under our existing financing agreements, including our bank credit facilities, could be impaired if one or more of our lenders fail to honor its contractual obligation to lend to us. Continuing or additional disruptions, including the bankruptcy or restructuring of certain financial institutions, may adversely affect the availability of credit already arranged and the availability and cost of credit in the future.

We might not be able to successfully manage the risks associated with selling and marketing products in the wholesale energy markets.

Our portfolio of derivative and other energy contracts consists of wholesale contracts to buy and sell commodities, including contracts for natural gas, natural gas liquids and other commodities that are settled by the delivery of the commodity or cash throughout the United States. If the values of these contracts change in a direction or manner that we do not anticipate or cannot manage, it could negatively affect our results of operations. In the past, certain marketing and trading companies have experienced severe financial problems due to price volatility in the energy commodity markets. In certain instances this volatility has caused companies to be unable to deliver energy commodities that they had guaranteed under contract. If such a delivery failure were to occur in one of our contracts, we might incur additional losses to the extent of amounts, if any, already paid to, or received from, counterparties. In addition, in our businesses, we often extend credit to our counterparties. Despite performing credit analysis prior to extending credit, we are exposed to the risk that we might not be able to collect amounts owed to

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us. If the counterparty to such a transaction fails to perform and any collateral that secures our counterparty's obligation is inadequate, we will suffer a loss. A general downturn in the economy and tightening of global credit markets could cause more of our counterparties to fail to perform than we have expected.

Our debt agreements impose restrictions on us that may adversely affect our ability to operate our business.

Certain of our debt agreements contain covenants that restrict or limit, among other things, our ability to create liens supporting indebtedness, sell assets, make certain distributions, and incur additional debt. In addition, our debt agreements contain, and those we enter into in the future may contain, financial covenants and other limitations with which we will need to comply. Our ability to comply with these covenants may be affected by many events beyond our control, and we cannot assure you that our future operating results will be sufficient to comply with the covenants or, in the event of a default under any of our debt agreements, to remedy that default.

Our failure to comply with the covenants in our debt agreements and other related transactional documents could result in events of default. Upon the occurrence of such an event of default, the lenders could elect to declare all amounts outstanding under a particular facility to be immediately due and payable and terminate all commitments, if any, to extend further credit. An event of default or an acceleration under one debt agreement could cause a cross-default or cross-acceleration of another debt agreement. Such a cross-default or cross-acceleration could have a wider impact on our liquidity than might otherwise arise from a default or acceleration of a single debt instrument. If an event of default occurs, or if other debt agreements cross-default, and the lenders under the affected debt agreements accelerate the maturity of any loans or other debt outstanding to us, we may not have sufficient liquidity to repay amounts outstanding under such debt agreements.

Our ability to repay, extend or refinance our existing debt obligations and to obtain future credit will depend primarily on our operating performance, which will be affected by general economic, financial, competitive, legislative, regulatory, business and other factors, many of which are beyond our control. Our ability to refinance existing debt obligations will also depend upon the current conditions in the credit markets and the availability of credit generally. If we are unable to meet its debt service obligations or obtain future credit on favorable terms, if at all, we could be forced to restructure or refinance our indebtedness, seek additional equity capital or sell assets. We may be unable to obtain financing or sell assets on satisfactory terms, or at all.

Our costs and funding obligations for our defined benefit pension plans and costs for our other postretirement benefit plans are affected by factors beyond our control.

We have defined benefit pension plans covering substantially all of our U.S. employees and other postretirement benefit plans covering certain eligible participants. The timing and amount of our funding requirements under the defined benefit pension plans depend upon a number of factors, including changes to pension plan benefits as well as factors outside of our control, such as asset returns, interest rates and changes in pension laws. Changes to these and other factors that can significantly increase our funding requirements could have a significant adverse effect on our financial condition. The amount of expenses recorded for our defined benefit pension plans and other postretirement benefit plans is also dependent on changes in several factors, including market interest rates and the returns on plan assets. Significant changes in any of these factors may adversely impact our future results of operations.

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***The continuation of recent economic conditions, including disruptions in the global credit markets, could adversely affect our results of operations*.**

The slowdown in the economy and the significant disruptions and volatility in global credit markets have the potential to negatively impact our businesses in many ways. Included among these potential negative impacts are reduced demand and lower prices for our products and services, increased difficulty in collecting amounts owed to us by our customers and a reduction in our credit ratings (either due to tighter rating standards or the negative impacts described above), which could result in reducing our access to credit markets, raising the cost of such access or requiring us to provide additional collateral to our counterparties.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

ISSUER PURCHASES OF EQUITY SECURITIES

Period	(a) Total Number of Shares Purchased	(b) Average Price Paid Per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs[1]	(d) Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs[2]
July 1 — July 31, 2008	2,959,951	$ 36.97	2,959,951	—
August 1 — August 31, 2008	—	—	—	—
September 1 — September 30, 2008	—	—	—	—
Total	2,959,951	$ 36.97	2,959,951	—

1 We announced a stock repurchase program on July 20, 2007. Our board of directors authorized the repurchase of up to $1 billion of the company's common stock. The stock repurchase program had no expiration date.

2 In July 2008, we completed our stock repurchase program by reaching the $1 billion limit authorized by our Board of Directors.

Item 5. Other Information

During the third quarter of 2008, we made responsive filings as required by law with federal antitrust regulators regarding notice we received that Carl C. Icahn and three affiliated entities were seeking statutory pre-clearance to own shares of our common stock in amounts totaling between $442 million and $2.018 billion.

Item 6. Exhibits

The following documents are included as exhibits to this report. Those exhibits below incorporated by reference herein are indicated as such by the information supplied in the parenthetical thereafter. Copies of the document have been included herewith for the exhibits denoted with an asterisk.

Exhibit 3 — The Williams Companies, Inc. By-laws, as amended on September 18, 2008 (filed on September 24, 2008 as Exhibit 3.1 to our current report on Form 8-K) and incorporated herein by reference.

Exhibit 10.1 — Form of Indemnification Agreement effective as of September 18, 2008, among The Williams Companies, Inc. and directors and officers of The Williams Companies, Inc. (filed on September 24, 2008 as Exhibit 10.1 to our current report on Form 8-K) and incorporated herein by reference.

*Exhibit 10.2 — Summary of Non-Management Director Compensation Action.

*Exhibit 12 — Computation of Ratio of Earnings to Fixed Charges.

*Exhibit 31.1 — Certification of Chief Executive Officer pursuant to Rules 13a-14(a) and 15d-14(a) promulgated under the Securities Exchange Act of 1934, as amended, and Item 601(b)(31) of Regulation S-K, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

*Exhibit 31.2 — Certification of Chief Financial Officer pursuant to Rules 13a-14(a) and 15d-14(a) promulgated under the Securities Exchange Act of 1934, as amended, and Item 601(b)(31) of Regulation S-K, as adopted pursuant to Section 302 of the

Sarbanes-Oxley Act of 2002.

*Exhibit 32 — Certification of Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

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SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

THE WILLIAMS COMPANIES, INC.
(Registrant)

/s/ Ted T. Timmermans
Ted T. Timmermans
Controller (Duly Authorized Officer and Principal Accounting Officer)

November 6, 2008

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EXHIBIT INDEX

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* Copy of document included herewith.

WMB 10-K 12/31/2007

Section 1: 10-K (FORM 10-K)

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549

Form 10-K

(Mark One)

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2007

or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission file number 1-4174

The Williams Companies, Inc.
(Exact name of Registrant as Specified in Its Charter)

Delaware *(State or Other Jurisdiction of Incorporation or Organization)*	**73-0569878** *(IRS Employer Identification No.)*
One Williams Center, Tulsa, Oklahoma *(Address of Principal Executive Offices)*	**74172** *(Zip Code)*

918-573-2000
(Registrant's Telephone Number, Including Area Code)

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, $1.00 par value	New York Stock Exchange
Preferred Stock Purchase Rights	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
5.50% Junior Subordinated Convertible Debentures due 2033

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☑

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☑

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☑	Accelerated filer ☐	Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☑

The aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, as of the last business day of the registrant's most recently completed second quarter was approximately $18,963,794,420.

The number of shares outstanding of the registrant's common stock outstanding at February 21, 2008 was 585,021,071.

DOCUMENTS INCORPORATED BY REFERENCE

Document	Parts Into Which Incorporated
Proxy Statement for the Annual Meeting of Stockholders to be held May 15, 2008 (Proxy Statement)	Part III

THE WILLIAMS COMPANIES, INC.
FORM 10-K

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DEFINITIONS

We use the following oil and gas measurements in this report:

Bcfe — means one billion cubic feet of gas equivalent determined using the ratio of one barrel of oil or condensate to six thousand cubic feet of natural gas.

Bcf/d — means one billion cubic feet per day.

British Thermal Unit or BTU — means a unit of energy needed to raise the temperature of one pound of water by one degree Fahrenheit.

BBtud — means one billion BTUs per day.

Dekatherms or Dth or Dt — means a unit of energy equal to one million BTUs.

Mbbls/d — means one thousand barrels per day.

Mcfe — means one thousand cubic feet of gas equivalent using the ratio of one barrel of oil or condensate to six thousand cubic feet of natural gas.

Mdt/d — means one thousand dekatherms per day.

MMcf — means one million cubic feet.

MMcf/d — means one million cubic feet per day.

MMcfe — means one million cubic feet of gas equivalent using the ratio of one barrel of oil or condensate to six thousand cubic feet of natural gas.

MMdt — means one million dekatherms or approximately one trillion BTUs.

MMdt/d — means one million dekatherms per day.

PART I

Item 1. *Business*

In this report, Williams (which includes The Williams Companies, Inc. and, unless the context otherwise requires, all of our subsidiaries) is at times referred to in the first person as "we," "us" or "our." We also sometimes refer to Williams as the "Company."

WEBSITE ACCESS TO REPORTS AND OTHER INFORMATION

We file our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, proxy statements and other documents electronically with the Securities and Exchange Commission (SEC) under the Securities Exchange Act of 1934, as amended (Exchange Act). You may read and copy any materials that we file with the SEC at the SEC's Public Reference Room at 450 Fifth Street, N.W., Washington, DC 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. You may also obtain such reports from the SEC's Internet website at *http://www.sec.gov*.

Our Internet website is *http://www.williams.com.* We make available free of charge on or through our Internet website our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. Our Corporate Governance Guidelines, Code of Ethics, board committee charters and Code of Business Conduct are also available on our Internet website. We will also provide, free of charge, a copy of any of our corporate documents listed above upon written request to our Secretary at Williams, One Williams Center, Suite 4700, Tulsa, Oklahoma 74172.

GENERAL

We are a natural gas company originally incorporated under the laws of the state of Nevada in 1949 and reincorporated under the laws of the state of Delaware in 1987. We were founded in 1908 when two Williams brothers began a construction company in Fort Smith, Arkansas. Today, we primarily find, produce, gather, process and transport natural gas. Our operations are concentrated in the Pacific Northwest, Rocky Mountains, Gulf Coast, and the Eastern Seaboard.

We continue to use Economic Value Added®(EVA®)[1] as the basis for disciplined decision making around the use of capital. EVA® is a tool that considers both financial earnings and a cost of capital in measuring performance. It is based on the idea that earning profits from an economic perspective requires that a company cover not only all of its operating expenses but also all of its capital costs. The two main components of EVA® are net operating profit after taxes and a charge for the opportunity cost of capital. We derive these amounts by making various adjustments to our reported results and financial position, and by applying a cost of capital. We look for opportunities to improve EVA® because we believe there is a strong correlation between EVA® improvement and creation of shareholder value.

Our goal is to create superior sustainable growth in EVA® and shareholder value. In early 2006, we set some ambitious three-year goals referred to as our game plan for growth. Our success in achieving the game plan for growth contributed to our significant accomplishments in 2007 designed to increase shareholder value, including:

- As a result of the sale of substantially all of our power assets to Bear Energy LP, a unit of The Bear Stearns Companies Inc. (NYSE: BSC) and strong business performance, our credit ratings were raised to investment grade.
- Continuing to increase our natural gas production through organic growth — natural gas production increased by 21 percent for the year.

[1] Economic Value Added® (EVA®) is a registered trademark of Stern, Stewart & Co.

- Initiating a $1 billion stock repurchase program.
- Creating a new pipeline-focused master limited partnership, Williams Pipeline Partners L.P. (WMZ)
- Continuing growing our midstream-focused master limited partnership, Williams Partners L.P. (WPZ), with two significant drop-down transactions.
- Successfully executing rate cases on both of our major pipeline systems, driving increased earnings in Gas Pipeline.

Our principal executive offices are located at One Williams Center, Tulsa, Oklahoma 74172. Our telephone number is 918-573-2000.

2007 HIGHLIGHTS

During third-quarter 2007, we formed Williams Pipeline Partners L.P. (WMZ) to own and operate natural gas transportation and storage assets. In January 2008, WMZ completed its initial public offering of 16.25 million common units at a price of $20.00 per unit. The underwriters also exercised their option to purchase an additional 1.65 million common units at the same price.

In December 2007, Williams Partners L.P. (WPZ) acquired certain of our membership interests in Wamsutter LLC, the limited liability company that owns the Wamsutter system, from us for $750 million.

In December 2007, we repurchased $213 million of 7.125 percent notes due September 2011 and $22 million of 8.125 percent notes due March 2012.

On November 28, 2007, Transcontinental Gas Pipe Line Corporation (Transco) filed a formal stipulation and agreement with the Federal Energy Regulatory Commission (FERC) resolving all substantive issues in Transco's pending 2006 rate case. Final resolution of the rate case is subject to approval by the FERC.

On November 9, 2007, we closed on the sale of substantially all of our power business to Bear Energy, LP, a unit of The Bear Stearns Companies, Inc., for $496 million, subject to post-closing adjustments. The assets sold included tolling contracts, full requirements contracts, tolling resales, heat rate options, related hedges and other related assets including certain property and software. This sale reduces the risk and complexity of our overall business.

In November 2007, our credit ratings were raised to investment grade based on improvements in our credit outlook. As we continue to invest and grow our natural gas businesses, our improved credit rating is expected to provide greater access to capital and more favorable loan terms. See additional discussion of credit ratings in *Management's Discussion and Analysis of Financial Condition*.

In July 2007, our Board of Directors authorized the repurchase of up to $1 billion of our common stock. We intend to purchase shares of our stock from time to time in open-market transactions or through privately negotiated or structured transactions at our discretion, subject to market conditions and other factors. This stock-repurchase program does not have an expiration date. During 2007, we repurchased approximately 16 million shares for $526 million (including transaction costs) at an average cost of $33.08 per share.

In April 2007, our Board of Directors approved a regular quarterly dividend of 10 cents per share, which reflects an increase of 11 percent compared to the 9 cents per share that we paid in each of the four prior quarters and marks the fourth increase in our dividend since late 2004.

On March 30, 2007, the FERC approved the stipulation and settlement agreement with respect to the rate case for Northwest Pipeline GP (Northwest Pipeline), formerly Northwest Pipeline Corporation.

FINANCIAL INFORMATION ABOUT SEGMENTS

See Note 17 of our Notes to Consolidated Financial Statements for information with respect to each segment's revenues, profits or losses and total assets. See Note 9 for information with respect to property, plant and equipment for each segment.

BUSINESS SEGMENTS

Substantially all our operations are conducted through our subsidiaries. To achieve organizational and operating efficiencies, our activities are primarily operated through the following business segments:

- *Exploration & Production* — produces, develops and manages natural gas reserves primarily located in the Rocky Mountain and Mid-Continent regions of the United States and is comprised of several wholly owned and partially owned subsidiaries including Williams Production Company LLC and Williams Production RMT Company.
- *Gas Pipeline* — includes our interstate natural gas pipelines and pipeline joint venture investments organized under our wholly owned subsidiary, Williams Gas Pipeline Company, LLC. Gas Pipeline also includes WMZ, our master limited partnership formed in 2007.
- *Midstream Gas & Liquids* — includes our natural gas gathering, treating and processing business and is comprised of several wholly owned and partially owned subsidiaries including Williams Field Services Group LLC and Williams Natural Gas Liquids, Inc. Midstream also includes WPZ, our master limited partnership formed in 2005.
- *Gas Marketing Services*— manages our natural gas commodity risk through purchases, sales and other related transactions, under our wholly owned subsidiary Williams Gas Marketing, Inc.
- *Other* — primarily consists of corporate operations. Other also includes our interest in Longhorn Partners Pipeline, L.P. (Longhorn).

This report is organized to reflect this structure.

Detailed discussion of each of our business segments follows.

Exploration & Production

Our Exploration & Production segment, which is comprised of several wholly owned and partially owned subsidiaries, including Williams Production Company LLC and Williams Production RMT Company (RMT), produces, develops, and manages natural gas reserves primarily located in the Rocky Mountain (primarily New Mexico, Wyoming and Colorado) and Mid-Continent (Oklahoma and Texas) regions of the United States. We specialize in natural gas production from tight-sands and shale formations and coal bed methane reserves in the Piceance, San Juan, Powder River, Arkoma, Green River and Fort Worth basins. Over 99 percent of Exploration & Production's domestic reserves are natural gas. Our Exploration & Production segment also has international oil and gas interests, which include a 69 percent equity interest in Apco Argentina Inc. (Apco Argentina), an oil and gas exploration and production company with operations in Argentina, and a four percent equity interest in Petrowayu S.A., a Venezuelan corporation that is the operator of a 100 percent interest in the La Concepcion block located in Western Venezuela.

Exploration & Production's primary strategy is to utilize its expertise in the development of tight-sands, shale, and coal bed methane reserves. Exploration & Production's current proved undeveloped and probable reserves provide us with strong capital investment opportunities for several years into the future. Exploration & Production's goal is to drill its existing proved undeveloped reserves, which comprise approximately 46 percent of proved reserves and to drill in areas of probable reserves. In addition, Exploration & Production provides a significant amount of equity production that is gathered and/or processed by our Midstream facilities in the San Juan basin.

Information for our Exploration & Production segment relates only to domestic activity unless otherwise noted. We use the terms "gross" to refer to all wells or acreage in which we have at least a partial working interest and "net" to refer to our ownership represented by that working interest.

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Gas reserves and wells

The following table summarizes our U.S. natural gas reserves as of December 31 (using market prices on December 31 held constant) for the year indicated:

	2007	2006	2005
		(Bcfe)	
Proved developed natural gas reserves	2,252	1,945	1,643
Proved undeveloped natural gas reserves	1,891	1,756	1,739
Total proved natural gas reserves	4,143	3,701	3,382

No major discovery or other favorable or adverse event has caused a significant change in estimated gas reserves since year-end 2007. We have not filed on a recurring basis estimates of our total proved net oil and gas reserves with any U.S. regulatory authority or agency other than the Department of Energy (DOE) and the SEC. The estimates furnished to the DOE have been consistent with those furnished to the SEC, although Exploration & Production has not yet filed any information with respect to its estimated total reserves at December 31, 2007, with the DOE. Certain estimates filed with the DOE may not necessarily be directly comparable due to special DOE reporting requirements, such as the requirement to report gross operated reserves only. In 2006 and 2005 the underlying estimated reserves for the DOE did not differ by more than five percent from the underlying estimated reserves utilized in preparing the estimated reserves reported to the SEC.

Approximately 98 percent of our year-end 2007 United States proved reserves estimates were audited in each separate basin by Netherland, Sewell & Associates, Inc. (NSAI). When compared on a well-by-well basis, some of our estimates are greater and some are less than the estimates of NSAI. However, in the opinion of NSAI, the estimates of our proved reserves are in the aggregate reasonable by basin and have been prepared in accordance with generally accepted petroleum engineering and evaluation principles. These principles are set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information promulgated by the Society of Petroleum Engineers. NSAI is satisfied with our methods and procedures in preparing the December 31, 2007 reserve estimates and saw nothing of an unusual nature that would cause NSAI to take exception with the estimates, in the aggregate, as prepared by us. Reserve estimates related to properties underlying the Williams Coal Seam Gas Royalty Trust, which comprise approximately two percent of our total U.S. proved reserves, were prepared by Miller and Lents, LTD.

On December 12, 2007, the SEC issued a "Concept Release" to obtain information about the extent and nature of the public's interest in revising oil and gas reserves disclosure requirements which exist in their current form in Regulation S-K and Regulation S-X under the Securities Act of 1933 and the Securities Exchange Act of 1934. The Commission adopted the current oil and gas reserves disclosure requirement between 1978 and 1982. The Concept Release is intended to address significant changes in the oil and gas industry. Some commentators have expressed concern that the Commission's rules have not adapted to current practices and may not provide investors with the most useful picture of oil and gas reserves public companies hold. Comments were due to the Commission on February 19, 2008. At this time it is not possible to determine what effect changes the SEC may make, if any, will have on our reserve estimates and disclosures.

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Oil and gas properties and reserves by basin

The table below summarizes 2007 activity and reserves for each of our areas, with further discussion following the table.

	Wells Drilled (Gross)	Wells Drilled (Operated)	Wells Producing (Gross)	Wells Producing (Net)	Wellhead Production (Net Bcfe)	Proved Reserves (Bcfe)	% of Total Proved Reserves
Piceance	574	544	2,467	2,295	197	2,847	69%
San Juan	146	47	3,109	821	55	576	14%
Powder River	637	457	4,831	2,200	62	413	10%
Mid-Continent	80	63	539	339	17	184	4%
Other	153	1	454	18	3	123	3%
Total	1,590	1,112	11,400	5,673	334	4,143	100%

Piceance basin

The Piceance basin is located in northwestern Colorado and is our largest area of concentrated development. During 2007 we operated an average of 25 drilling rigs in the basin. As of December 2007, 14 of these rigs were the new high efficiency rigs designed to drill up to 22 wells from one location. This area has approximately 1,760 undrilled proved locations in inventory. Within this basin we own and operate natural gas gathering facilities including some 280 miles of gathering lines and associated field compression. Approximately 88% of the gas gathered is our own equity production. The gathering system also includes six processing plants and associated treating facilities with a total capacity of 900,000 Mcfd. During 2007, these plants recovered approximately 54 million gallons of natural gas liquids (NGL's) which were marketed separately from the residue natural gas.

San Juan basin

The San Juan basin is located in northwest New Mexico and southwest Colorado.

Powder River basin

The Powder River basin is located in northeast Wyoming. The Powder River basin includes large areas with multiple coal seam potential, targeting thick coal bed methane formations at shallow depths. We have a significant inventory of undrilled locations, providing long-term drilling opportunities.

Mid-Continent properties

The Mid-Continent properties are located in the southeastern Oklahoma portion of the Arkoma basin and the Barnett Shale in the Fort Worth basin of Texas.

Other properties

Other properties are primarily comprised of interests in the Green River basin in southwestern Wyoming. Also included is exploration activity and other miscellaneous activity.

The following table summarizes our leased acreage as of December 31, 2007:

	Gross Acres	Net Acres
Developed	873,923	447,820
Undeveloped	1,211,865	627,393

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Operating statistics

We focus on lower-risk development drilling. Our drilling success rate was 99 percent in 2007, 2006 and 2005. The following tables summarize domestic drilling activity by number and type of well for the periods indicated:

Number of Wells	Gross Wells	Net Wells
Development:		
Drilled		
2007	1,590	904
2006	1,783	954
2005	1,627	867
Successful		
2007	1,581	899
2006	1,770	948
2005	1,615	859

Because we currently have a low-risk drilling program in proven basins, the main component of risk that we manage is price risk. In February 2007, we entered into a five-year unsecured credit agreement with certain banks in order to reduce margin requirements related to our hedging activities as well as lower transaction fees. Margin requirements, if any, under this new facility are dependent on the level of hedging with the banks and on natural gas reserves value. Exploration & Production natural gas hedges for 2008 domestic natural gas production consist of NYMEX fixed price contracts of 70 MMcf/d (whole year) and approximately 397 MMcf/d in regional collars (whole year). Our natural gas production hedges in 2007 consisted of 172 MMcf/d in NYMEX fixed price hedges and an additional 271 MMcf/d in NYMEX and basin level collars. A collar is an option contract that sets a gas price floor and ceiling for a certain volume of natural gas. Hedging decisions are made considering the overall Williams commodity risk exposure and are not executed independently by Exploration & Production; there are expected future gas purchases for other Williams entities which when taken as a net position may offset price risk related to Exploration & Production's expected future gas sales.

The following table summarizes our domestic sales and cost information for the years indicated:

	2007	2006	2005
Total net production sold (in Bcfe)	333.1	274.4	223.5
Average production costs including production taxes per thousand cubic feet of gas equivalent (Mcfe) produced	$ 0.98	$ 1.02	$ .92
Average sales price per Mcfe	$ 4.92	$ 5.24	$ 6.41
Realized impact of hedging contracts (Loss)	$ 0.16	$ (0.73)	$ (1.61)

Acquisitions & divestitures

Through transactions totaling approximately $77 million, Exploration & Production expanded its acreage position and purchased producing properties in the Fort Worth basin in north-central Texas and also expanded its acreage position in the Highlands area of the Piceance basin.

In January 2008, we sold a contractual right to a production payment on certain future international hydrocarbon production in Peru for approximately $148 million. We have received $118 million in cash and $29 million has been placed in escrow subject to certain post-closing conditions and adjustments. We will recognize a pre-tax gain of approximately $118 million in the first quarter of 2008 related to the initial cash received. As a result of the contract termination, we have no further interests associated with the crude oil concession. We had obtained these interests through our acquisition of Barrett Resources Corporation in 2001.

Other information

In 1993, Exploration & Production conveyed a net profits interest in certain of its properties to the Williams Coal Seam Gas Royalty Trust. Substantially all of the production attributable to the properties conveyed to the trust was from the Fruitland coal formation and constituted coal seam gas. We subsequently sold trust units to the public in an underwritten public offering and retained 3,568,791 trust units then representing 36.8 percent of outstanding trust units. We have previously sold trust units on the open market, with our last sales in June 2005. As of February 1, 2008, we own 789,291 trust units.

International exploration and production interests

We also have investments in international oil and gas interests. If combined with our domestic proved reserves, our international interests would make up approximately 3.6 percent of our total proved reserves.

Gas Pipeline

We own and operate, through Williams Gas Pipeline Company, LLC (WMZ) and its subsidiaries, a combined total of approximately 14,200 miles of pipelines with a total annual throughput of approximately 2,700 trillion British Thermal Units of natural gas and peak-day delivery capacity of approximately 12 MMdt of gas. Gas Pipeline consists of Transcontinental Gas Pipe Line Corporation and Northwest Pipeline GP. Gas Pipeline also holds interests in joint venture interstate and intrastate natural gas pipeline systems including a 50 percent interest in Gulfstream Natural Gas System, L.L.C. Gas Pipeline also includes our new master limited partnership, Williams Pipeline Partners, L.P.

Transcontinental Gas Pipe Line Corporation (Transco)

Transco is an interstate natural gas transportation company that owns and operates a 10,300-mile natural gas pipeline system extending from Texas, Louisiana, Mississippi and the offshore Gulf of Mexico through Alabama, Georgia, South Carolina, North Carolina, Virginia, Maryland, Pennsylvania, and New Jersey to the New York City metropolitan area. The system serves customers in Texas and 11 southeast and Atlantic seaboard states, including major metropolitan areas in Georgia, North Carolina, New York, New Jersey, and Pennsylvania.

Pipeline system and customers

At December 31, 2007, Transco's system had a mainline delivery capacity of approximately 4.7 MMdt of natural gas per day from its production areas to its primary markets. Using its Leidy Line along with market-area storage and transportation capacity, Transco can deliver an additional 3.7 MMdt of natural gas per day for a system-wide delivery capacity total of approximately 8.4 MMdt of natural gas per day. Transco's system includes 45 compressor stations, five underground storage fields, two liquefied natural gas (LNG) storage facilities. Compression facilities at a sea level-rated capacity total approximately 1.5 million horsepower.

Transco's major natural gas transportation customers are public utilities and municipalities that provide service to residential, commercial, industrial and electric generation end users. Shippers on Transco's system include public utilities, municipalities, intrastate pipelines, direct industrial users, electrical generators, gas marketers and producers. One customer accounted for approximately 12 percent of Transco's total revenues in 2007. Transco's firm transportation agreements are generally long-term agreements with various expiration dates and account for the major portion of Transco's business. Additionally, Transco offers storage services and interruptible transportation services under short-term agreements.

Transco has natural gas storage capacity in five underground storage fields located on or near its pipeline system or market areas and operates three of these storage fields. Transco also has storage capacity in an LNG storage facility and operates the facility. The total usable gas storage capacity available to Transco and its customers in such underground storage fields and LNG storage facility and through storage service contracts is approximately 216 billion cubic feet of gas. In addition, wholly owned subsidiaries of Transco operate and hold a 35 percent ownership interest in Pine Needle LNG Company, LLC, an LNG storage facility with 4 billion cubic feet of storage capacity. Storage capacity permits Transco's customers to inject gas into storage during the summer and off-peak periods for delivery during peak winter demand periods.

Transco expansion projects

The pipeline projects listed below were completed during 2007 or are future pipeline projects for which we have customer commitments.

Potomac Expansion Project

In November 2007, we placed into service the Potomac Expansion Project, an expansion of our existing natural gas transmission system from receipt points in North Carolina to delivery points in the greater Baltimore and Washington, D.C. metropolitan areas. The second phase of the project involving installation of certain appurtenant facilities will be completed in fall 2008. The capital cost of the project is estimated to be approximately $88 million.

Leidy to Long Island Expansion Project

In December 2007, we placed into service the Leidy to Long Island Expansion Project, an expansion of our existing natural gas transmission system in Zone 6 from the Leidy Hub in Pennsylvania to Long Island, New York. The capital cost of the project is estimated to be approximately $169 million.

Sentinel Expansion Project

The Sentinel Expansion Project will involve an expansion of our existing natural gas transmission system from the Leidy Hub in Clinton County, Pennsylvania and from the Pleasant Valley interconnection with Cove Point LNG in Fairfax County, Virginia to various delivery points requested by the shippers under the project. The capital cost of the project is estimated to be up to approximately $169 million. Transco plans to place the project into service in phases, in late 2008 and late 2009.

Pascagoula Expansion Project

The Pascagoula Expansion Project will involve the construction of a new pipeline to be jointly owned with Florida Gas Transmission connecting Transco's existing Mobile Bay Lateral to the outlet pipeline of a proposed liquefied natural gas import terminal in Mississippi. Transco's share of the estimated capital cost of the project is up to $37 million. Transco plans to place the project into service in mid-2011.

Operating statistics

The following table summarizes transportation data for the Transco system for the periods indicated:

	2007	2006	2005
	(In trillion British Thermal Units)		
Market-area deliveries:			
Long-haul transportation	839	795	755
Market-area transportation	875	817	853
Total market-area deliveries	1,714	1,612	1,608
Production-area transportation	190	247	278
Total system deliveries	1,904	1,859	1,886
Average Daily Transportation Volumes	5.2	5.1	5.2
Average Daily Firm Reserved Capacity	6.6	6.6	6.6

Transco's facilities are divided into eight rate zones. Five are located in the production area, and three are located in the market area. Long-haul transportation involves gas that Transco receives in one of the production-area zones and delivers to a market-area zone. Market-area transportation involves gas that Transco both receives and delivers within the market-area zones. Production-area transportation involves gas that Transco both receives and delivers within the production-area zones.

Northwest Pipeline GP (Northwest Pipeline)

Northwest Pipeline is an interstate natural gas transportation company that owns and operates a natural gas pipeline system extending from the San Juan basin in northwestern New Mexico and southwestern Colorado through Colorado, Utah, Wyoming, Idaho, Oregon and Washington to a point on the Canadian border near Sumas, Washington. Northwest Pipeline provides services for markets in California, Arizona, New Mexico, Colorado, Utah, Nevada, Wyoming, Idaho, Oregon and Washington directly or indirectly through interconnections with other pipelines.

Pipeline system and customers

At December 31, 2007, Northwest Pipeline's system, having long-term firm transportation agreements with peaking capacity of approximately 3.4 MMdt of natural gas per day, was composed of approximately 3,900 miles of mainline and lateral transmission pipelines and 41 transmission compressor stations having a combined sea level-rated capacity of approximately 473,000 horsepower.

Northwest implemented new rates effective January 1, 2007 that were approved by FERC. The rate case settlement established that general system firm transportation rates on Northwest's system increased from $0.30760 to $0.40984 per Dth.

In 2007, Northwest Pipeline served a total of 132 transportation and storage customers. Transportation customers include distribution companies, municipalities, interstate and intrastate pipelines, gas marketers and direct industrial users. The two largest customers of Northwest Pipeline in 2007 accounted for approximately 20 percent and 11.5 percent, of its total operating revenues. No other customer accounted for more than 10 percent of Northwest Pipeline's total operating revenues in 2007. Northwest Pipeline's firm transportation agreements are generally long-term agreements with various expiration dates and account for the major portion of Northwest Pipeline's business. Additionally, Northwest Pipeline offers interruptible and short-term firm transportation service.

As a part of its transportation services, Northwest Pipeline utilizes underground storage facilities in Utah and Washington enabling it to balance daily receipts and deliveries. Northwest Pipeline also owns and operates an LNG storage facility in Washington that provides service for customers during a few days of extreme demands. These storage facilities have an aggregate firm delivery capacity of approximately 600 million cubic feet of gas per day.

Northwest Pipeline expansion projects

The pipeline projects listed below were completed during 2007 or are future pipeline projects for which we have customer commitments.

Jackson Prairie Underground Expansion

The Jackson Prairie Storage Project, connected to Northwest's transmission system near Chehalis, Washington, is operated by Puget Sound Energy and is jointly owned by Northwest, Puget Sound Energy and Avista Corporation. A phased capacity expansion is currently underway and a deliverability expansion is planned for 2008. Northwest's one-third interest in the project includes 104 MMcf per day of planned 2008 deliverability expansion and approximately 1.2 Bcf of working natural gas storage capacity to be developed over approximately a four year period from 2007 through 2010. Northwest's one-third share of the cost of the deliverability expansion is estimated to be $16 million. Northwest's estimated capital cost for the capacity expansion component of the new storage service is $6.1 million, primarily for base natural gas.

Colorado Hub Connection Project

Northwest has proposed installing a new lateral to connect the White River Hub near Meeker, Colorado to Northwest's mainline near Sand Springs, Colorado. This project is referred to as the Colorado Hub

Connection, or CHC Project. It is estimated that the construction of the CHC Project would cost up to $53 million and could begin service as early as November 2009.

Parachute Lateral

Northwest placed its Parachute Lateral facilities in service on May 16, 2007, and began collecting revenues of approximately $0.87 million per month. The expansion increased capacity by 450 Mdt/d at a cost of approximately $86 million.

On August 24, 2007, Northwest filed an application with FERC to amend its certificate of public convenience and necessity issued for the Parachute Lateral to allow the transfer of the ownership of its Parachute Lateral facilities to a newly created entity, Parachute Pipeline LLC (Parachute), which is owned by Midstream through one of its wholly-owned subsidiaries Williams Field Services Company, LLC (Williams Field Services). This application was approved by FERC on November 15, 2007, and Northwest sold the Parachute on December 31, 2007. The Parachute Lateral facilities are located in Rio Blanco and Garfield counties, Colorado.

As contemplated in the application for amendment, Parachute has leased the facilities back to Northwest, and as a result of the sale has become a Midstream subsidiary. Northwest will continue to operate the facilities under the FERC certificate. When Midstream completes its Willow Creek Processing Plant, the lease (subject to further regulatory approval) will terminate, and Parachute will assume full operational control and responsibility for the Parachute Lateral.

Operating statistics

The following table summarizes volume and capacity data for the Northwest Pipeline system for the periods indicated:

	2007	2006	2005
	(In trillion British Thermal Units)		
Total Transportation Volume	757	676	673
Average Daily Transportation Volumes	2.1	1.9	1.8
Average Daily Reserved Capacity Under Long-Term Base Firm Contracts, excluding peak capacity	2.5	2.5	2.5
Average Daily Reserved Capacity Under Short-Term Firm Contracts(1)	.8	.9	.8

(1) Consists primarily of additional capacity created from time to time through the installation of new receipt or delivery points or the segmentation of existing mainline capacity. Such capacity is generally marketed on a short-term firm basis, because it does not involve the construction of additional mainline capacity.

Gulfstream Natural Gas System, L.L.C. (Gulfstream)

Gulfstream is a natural gas pipeline system extending from the Mobile Bay area in Alabama to markets in Florida. Gas Pipeline and Spectra Energy (formerly known as Duke Energy), through their respective subsidiaries, each holds a 50 percent ownership interest in Gulfstream and provides operating services for Gulfstream. At December 31, 2007, our equity investment in Gulfstream was $439 million.

Gulfstream expansion projects

Gulfstream has entered into a precedent agreement and a related firm transportation service agreement pursuant to which, subject to the receipt of all necessary regulatory approvals and other conditions precedent therein, Gulfstream intends to extend the pipeline system into South Florida and fully subscribe the remaining 345 Mdt/d of firm capacity on the existing pipeline system on a long-term basis. The estimated capital cost of this project is anticipated to be up to approximately $130 million, with Gas Pipeline's share being 50 percent of such costs. Gulfstream also has executed a precedent agreement and a related firm transportation service agreement pursuant to which, subject to the receipt of all necessary regulatory approvals and other conditions precedent therein, it intends to construct and fully subscribe on a long-term basis the first incremental expansion of

Gulfstream's mainline capacity, increasing the current mainline capacity of 1.1 MMdt/d to 1.255 MMdt/d. The estimated capital cost of this expansion is anticipated to be up to approximately $153 million, with Gas Pipeline's share being 50 percent of such costs. No significant increase in operations personnel is expected as a result of these two projects.

Williams Pipeline Partners L.P

WMZ was formed to own and operate natural gas transportation and storage assets. We currently own approximately 45.7 percent limited partnership interest and a 2 percent general partner interest in WMZ. WMZ provides us with lower cost of capital that is expected to enable growth of our Gas Pipeline business. WMZ also creates a vehicle to monetize our qualifying assets. Such transactions, which are subject to approval by the boards of directors of Williams and WMZ's general partner, allow us to retain control of the assets through our ownership interest in WMZ. A subsidiary of ours serves as the general partner of WMZ. The initial asset of WMZ is a 35 percent interest in Northwest Pipeline.

Midstream Gas & Liquids

Our Midstream segment, one of the nation's largest natural gas gatherers and processors, has primary service areas concentrated in the major producing basins in Colorado, New Mexico, Wyoming, the Gulf of Mexico, Venezuela and western Canada. Midstream's primary businesses — natural gas gathering, treating, and processing; NGL fractionation, storage and transportation; and oil transportation — fall within the middle of the process of taking natural gas and crude oil from the wellhead to the consumer. NGLs, ethylene and propylene are extracted/produced at our plants, including our Canadian and Gulf Coast olefins plants. These products are used primarily for the manufacture of plastics, home heating and refinery feedstock.

Although most of our gas services are performed for a volumetric-based fee, a portion of our gas processing contracts are commodity-based and include two distinct types of commodity exposure. The first type includes "Keep Whole" processing contracts whereby we own the rights to the value from NGLs recovered at our plants and have the obligation to replace the lost heating value with natural gas. Under these contracts, we are exposed to the spread between NGLs and natural gas prices. The second type consists of "Percent of Liquids" contracts whereby we receive a portion of the extracted liquids with no direct exposure to the price of natural gas. Under these contracts, we are only exposed to NGL price movements.

Our Canadian and Gulf Liquids olefin facilities have commodity price exposure. In Canada, we are exposed to the spread between the price for natural gas and the olefinic products we produce. In the Gulf Coast, our feedstock for the ethane cracker is ethane and propane; as a result, we are exposed to the price spread between ethane and propane and ethylene and propylene. In the Gulf Coast, we also purchase refinery grade propylene and fractionate it into polymer grade propylene and propane; as a result we are exposed to the price spread between those commodities.

Key variables for our business will continue to be:

- retaining and attracting customers by continuing to provide reliable services;
- revenue growth associated with additional infrastructure either completed or currently under construction;
- disciplined growth in our core service areas;
- prices impacting our commodity-based processing and olefin activities.

Gathering and processing

We own and/or operate domestic gas gathering and processing assets primarily within the western states of Wyoming, Colorado and New Mexico, and the onshore and offshore shelf and deepwater areas in and around the Gulf Coast states of Texas, Louisiana, Mississippi and Alabama. These assets consist of approximately 8,700 miles of gathering pipelines, nine processing plants (one partially owned) and five natural gas treating plants with a combined daily inlet capacity of nearly 6.5 billion cubic feet per day. Some of these assets are owned through our interest in WPZ (see William Partners L.P. section below).

Geographically, our Midstream natural gas assets are positioned to maximize commercial and operational synergies with our other assets. For example, most of our offshore gathering and processing assets attach and process or condition natural gas supplies delivered to the Transco pipeline. Also, our gathering and processing facilities in the San Juan Basin handle about 85 percent of our Exploration & Production group's wellhead production in this basin. Both our San Juan Basin and Southwest Wyoming systems deliver gas volumes into Northwest Pipeline's interstate system in addition to third party interstate systems.

Included in the natural gas assets listed above are the assets of Discovery Producer Services LLC and its subsidiary Discovery Gas Transmission Services LLC (Discovery). WPZ owns a partial interest in Discovery and we operate its facilities. Discovery's assets include a cryogenic natural gas processing plant near Larose, Louisiana, a natural gas liquids fractionator plant near Paradis, Louisiana and an offshore natural gas gathering and transportation system in the Gulf of Mexico.

In addition to these natural gas assets, we own and operate three crude oil pipelines totaling approximately 310 miles with a capacity of more than 300,000 barrels per day. This includes our Mountaineer, Alpine and BANJO crude oil pipeline systems in the deepwater Gulf of Mexico.

The BANJO oil pipeline and Seahawk gas pipeline run parallel and deliver production across two producer-owned spar-type floating production systems from the Anadarko Petroleum Corporation (Anadarko) operated Boomvang and Nansen field areas in the western Gulf of Mexico. These pipelines were placed in service in 2002.

Our 18 inch oil pipeline, Alpine, which became operational in 2003, is our second western gulf crude oil pipeline. The pipeline extends 96 miles from Garden Banks Block 668 in the central Gulf of Mexico to our shallow-water platform at Galveston Area Block A244. From this platform, the oil is delivered onshore through ExxonMobil's Hoover Offshore Oil Pipeline System under a joint tariff agreement. This production is coming from the Gunnison field, which is located in 3,150 feet of water and operated by Anadarko.

Our Devils Tower floating production system and associated pipelines were placed in service in 2004. Initially built to serve the Devils Tower field, the floating production system is located in Mississippi Canyon Block 773, approximately 150 miles south-southwest of Mobile, Alabama. During the fourth quarter of 2005, the platform's service expanded to include tie-backs of production from the Triton and Goldfinger fields in addition to the host Devils Tower field. Construction is currently underway to add topside capacity for the recently dedicated Bass Lite gas discovery. Full field production from Bass Lite is expected mid-year 2008. Located in 5,610 feet of water, it is the world's deepest dry tree spar. The platform, which is operated by ENI Petroleum on our behalf, is capable of producing 60 MMcf/d of natural gas and 60 Mbbls/d of oil.

The Devils Tower project includes gas and oil pipelines. The 139-mile Canyon Chief gas pipeline consists of 18-inch diameter pipe. The 155-mile Mountaineer oil pipeline is a combination of 18- and 20-inch diameter pipe. The gas is delivered into Transco's pipeline, and processed at our Mobile Bay plant to recover the NGLs. The oil is transported to ChevronTexaco's Empire Terminal in Plaquemines Parish, Louisiana. These associated pipelines are significantly oversized relative to the Devils Tower spar top-side capacity.

Gulf Coast petrochemical and olefins

We own a 10/12 interest in and are the operator for an ethane cracker at Geismar, Louisiana, with a total production capacity of 1.3 billion pounds per year of ethylene. In July 2007, we exercised our right of first refusal to acquire BASF's 5/12th ownership interest in the Geismar olefins facility bringing our ownership position up to the current 10/12 interest. We also own an ethane pipeline system and a propylene splitter and its related pipeline system in Louisiana.

Canada

Our Canadian operations include an olefin liquids extraction plant located near Ft. McMurray, Alberta and an olefin fractionation facility near Edmonton, Alberta. Our facilities extract olefinic liquids from the off-gas produced from third party oil sands bitumen upgrading and then fractionate, treat, store, terminal and sell the propane, propylene, butane and condensate recovered from this process. We continue to be the only olefins fractionator in Western Canada and the only treater-processor of oil sands upgrader off-gas. These operations extract valuable petrochemical feedstocks from upgrader off-gas streams allowing the upgraders to burn cleaner natural gas streams and reduce overall air emissions. The extraction plant has processing capacity in excess of 100 MMcf/d with the ability to recover in excess of 15 Mbbls/d of olefin and NGL products.

Venezuela

Our Venezuelan investments involve gas compression and gas processing and natural gas liquids fractionation operations. We own controlling interests and operate three gas compressor facilities which provide roughly 70 percent of the gas injections in eastern Venezuela. These facilities help stabilize the reservoir and enhance the recovery of crude oil by re-injecting natural gas at high pressures. We also own a 49.25 percent interest in two 400 MMcf/d natural gas liquids extraction plants, a 50,000 barrels per day natural gas liquids fractionation plant and associated storage and refrigeration facilities.

Other

We own interests in and/or operate NGL fractionation and storage assets. These assets include two partially owned NGL fractionation facilities near Conway, Kansas and Baton Rouge, Louisiana that have a combined capacity in excess of 167,000 barrels per day. We also own approximately 20 million barrels of NGL storage capacity in central Kansas. Some of these assets are owned through our interest in WPZ.

We also own a 14.6% interest in Aux Sable Liquid Products and its Channahon, Illinois gas processing and NGL fractionation facility near Chicago. The facility is capable of processing up to 2.1 Bcf/d of natural gas from the Alliance Pipeline system and fractionating approximately 87,000 barrels per day of extracted liquids into NGL products.

Williams Partners L.P (WPZ)

WPZ was formed to engage in the business of gathering, transporting and processing natural gas and fractionating and storing NGLs. We currently own approximately a 21.6 percent limited partnership interest and a 2 percent general partner interest in WPZ. WPZ provides us with lower cost of capital that is expected to enable growth of our Midstream business. WPZ also creates a vehicle to monetize our qualifying assets. Such transactions, which are subject to approval by the boards of directors of both Williams and WPZ’s general partner, allow us to retain control of the assets through our ownership interest in WPZ.

WPZ’s asset portfolio at its initial public offering in 2005 consisted of a 40 percent interest in Discovery, the Carbonate Trend gathering pipeline, three integrated NGL storage facilities near Conway, Kansas and a 50 percent interest in an NGL fractionator near Conway, Kansas.

During 2006, WPZ acquired Williams Four Corners, LLC which owns a 3,500-mile natural gas gathering system in the San Juan Basin in New Mexico and Colorado with capacity of nearly 2 Bcf/d; the Ignacio natural gas processing plant in Colorado and the Kutz and Lybrook natural gas processing plants in New Mexico, which have a combined processing capacity of 760 MMcf/d; and the Milagro and Esperanza natural gas treating plants in New Mexico, which are designed to remove carbon dioxide from up to 750 MMcf of natural gas per day.

In June 2007, WPZ acquired an additional 20 percent interest in Discovery. WPZ now owns a 60 percent interest in the Discovery gathering, transportation, processing and NGL fractionation system, the remainder of which is owned by third parties.

In December 2007, WPZ acquired certain ownership interests in Wamsutter LLC from us for $750 million. Wamsutter LLC owns a 1,700 mile natural gas gathering system in the Washakie Basin in south-central Wyoming and the Echo Springs natural gas processing plant in Sweetwater County, Wyoming.

Expansion projects

Gathering and processing — west

During the first quarter of 2007, we completed construction at our existing gas processing complex located near Opal, Wyoming, to add a fifth cryogenic gas processing train capable of processing up to 350 MMcf/d, bringing total Opal capacity to approximately 1.5 Bcf/d. This plant expansion increased Opal's processing capacity by more than 30 percent and became operational during the first quarter.

In the first quarter of 2007, we also announced plans to construct and operate the Willow Creek facility a 450 MMcf/d natural gas processing plant in the Piceance Basin of western Colorado, where Exploration and Production has its most significant volume of natural gas production, reserves and development activity. Exploration and Production's existing Piceance Basin processing plants are primarily designed to condition the natural gas to meet quality specifications for pipeline transmission, not to maximize the extraction of NGLs. We expect the new Willow Creek facility to recover 25,000 barrels per day of NGLs at startup, which is expected to be in the third quarter of 2009.

In December 2007, Midstream purchased the Parachute Lateral system from Gas Pipeline. The system is a 37.6-mile expansion, originally placed in service by Gas Pipelines in May 2007, and provides capacity of 450 Mdt/d through a 30-inch diameter line, transporting residue gas from the Piceance basin to the Greasewood Hub in northwest Colorado. The Willow Creek facility will straddle the Parachute Lateral pipeline and will process gas flowing through the pipeline. In an arrangement approved by the FERC, Midstream will lease the pipeline to Gas Pipeline, who will continue to operate the pipeline until completion of a planned FERC abandonment filing.

In addition, Midstream acquired an existing natural gas pipeline from Gas Pipeline, and has begun the process of converting it from natural gas to NGL service and constructing additional pipeline to create a pipeline alternative for NGLs currently being transported by truck from Exploration & Production's existing Piceance basin processing plants to a major NGL transportation pipeline system.

In 2006, we entered into an agreement to develop new pipeline capacity for transporting NGLs from production areas in southwestern Wyoming to central Kansas. The other party to the agreement reimbursed us for the development costs we had incurred for the proposed pipeline and acquired 99 percent of the pipeline, known as Overland Pass Pipeline Company, LLC. We retained a 1 percent interest and have the option to increase our ownership to 50 percent and become the operator within two years of the pipeline becoming operational. Start-up is planned for mid-2008. Additionally, we have agreed to dedicate our equity NGL volumes from our two Wyoming plants and the new Willow Creek facility for transport under a long-term shipping agreement. The terms represent significant savings compared with the existing tariff and other alternatives considered.

Gathering and processing — deepwater projects

The deepwater Gulf continues to be an attractive growth area for our Midstream business. Since 1997, we have invested almost $1.3 billion in new midstream assets in the Gulf of Mexico. These facilities provide both onshore and offshore services through pipelines, platforms and processing plants. The new facilities could also attract incremental gas volumes to Transco's pipeline system in the southeastern United States.

During 2007, we have continued construction activities on the Perdido Norte project which includes oil and gas lines that would expand the scale of our existing infrastructure in the western deepwater of the Gulf of Mexico. In addition, we completed agreements with certain producers to provide gathering, processing and transportation services over the life of the reserves. We also intend to expand our onshore Markham gas processing facility to adequately serve this new gas production. The scale of the project has increased to include additional pipeline and more efficient processing capacity and is now estimated to cost approximately $560 million and to be in service in the third quarter of 2009.

Chevron and Anadarko are dedicating to us the transport of production from their current and future ownership in a defined area surrounding the Blind Faith discovery in the deepwater Gulf of Mexico. To accommodate production from the Blind Faith acreage and the surrounding blocks, we have agreed to extend our Canyon Chief and Mountaineer pipelines to the producer-owned floating production facility. We expect to have the extensions ready for service in the second quarter of 2008. The approximately $250 million project will facilitate a 37-mile extension of each pipeline. The agreement also creates opportunities for us to move natural gas from the Blind Faith discovery through our Mobile Bay, Alabama, processing plant and our Transco and Gulfstream interstate pipeline systems. Recovered NGLs from Blind Faith also could be fractionated at our facilities in Baton Rouge or Paradis, Louisiana.

Customers and operations

Our domestic gas gathering and processing customers are generally natural gas producers who have proved and/or producing natural gas fields in the areas surrounding our infrastructure. During 2007, these operations gathered and processed gas for approximately 215 gas gathering and processing customers. Our top three gathering and processing customers accounted for about 45 percent of our domestic gathering and processing revenue. Our gathering and processing agreements are generally long-term agreements.

In addition to our gathering and processing operations, we market NGLs and petrochemical products to a wide range of users in the energy and petrochemical industries. We provide these products to third parties from the production at our domestic facilities. The majority of domestic sales are based on supply contracts of less than one year in duration. The production from our Canadian facilities is marketed in Canada and in the United States.

Our Venezuelan assets were constructed and are currently operated for the exclusive benefit of Petróleos de Venezuela S.A under long-term contracts. These significant contracts have a remaining term between 10 and 14 years and our revenues are based on a combination of fixed capital payments, throughput volumes, and, in the case of one of the gas compression facilities, a minimum throughput guarantee. The Venezuelan government has continued its public criticism of U.S. economic and political policy, has implemented unilateral changes to existing energy related contracts, and continues to publicly declare that additional energy contracts will be unilaterally amended and privately held assets will be expropriated, escalating our concern regarding political risk in Venezuela.

Operating statistics

The following table summarizes our significant operating statistics for Midstream:

	2007	2006	2005
Volumes(1):			
Domestic Gathering (trillion British Thermal Units)	1,045	1,181	1,253
Domestic Natural Gas Liquid Production (Mbbls/d)(2)	163	152	144
Crude Oil Gathering (Mbbls/d)(2)	80	86	88
Processing Volumes (trillion British Thermal Units)	937	833	721

(1) Excludes volumes associated with partially owned assets that are not consolidated for financial reporting purposes.

(2) Annual Average Mbbls/d

Gas Marketing Services

Gas Marketing Services primarily supports our natural gas businesses by providing marketing and risk management services, which include marketing and hedging the gas produced by Exploration & Production, and procuring fuel and shrink gas and hedging natural gas liquids sales for Midstream. In addition, Gas Marketing manages various natural gas-related contracts such as transportation, storage, and related hedges, and provides services to third-parties, such as producers.

Gas Marketing Services' natural gas sales volumes, including sales volumes to other segments, were 2.3 Bcf/d, 2.1 Bcf/d and 2.1 Bcf/d for the years ending December 31, 2007, 2006 and 2005, respectively. Gas Marketing Services' natural gas purchase volumes, including purchases from other segments, were 2.4 Bcf/d, 2.3 Bcf/d and 2.2 Bcf/d for the same periods.

As of December 31, 2007, Gas Marketing Services has approximately 159 customers compared with approximately 163 customers at the end of 2006.

Our Exploration and Production and Midstream segments may execute commodity hedges with Gas Marketing Services. In turn, Gas Marketing Services may execute offsetting derivative contracts with unrelated third parties.

As a result of the sale of a substantial portion of our Power business in the fourth quarter of 2007, Gas Marketing Services also is responsible for certain remaining legacy natural gas contracts and positions. We intend to liquidate a substantial portion of these legacy contracts. During 2007, we substantially reduced the overall legacy positions remaining. Until such legacy positions are liquidated, segment results may experience mark- to-market volatility from commodity-based derivatives that represent economic hedges but are not designated as hedges for accounting purposes or do not qualify for hedge accounting. However, this mark-to-market volatility is expected to be significantly reduced compared to previous levels.

Other

At December 31, 2007, we owned approximately 99.3 percent of the Class B Interests in Longhorn Partners Pipeline LP (Longhorn), which owned a refined petroleum products pipeline from Houston, Texas to El Paso, Texas. The Class B Interests are preferred interests but subordinate to other preferred interests, and the common interests are subordinate to both. It is uncertain whether we will ever receive any payments related to our Class B Interests or our common interests, however any such amounts related to these interests were fully impaired in 2005, and will only be recognized as income when received.

We continue to receive payments associated with the 2005 transfer of the First Amended and Restated Pipeline Operating Services Agreement to a third party. The management of Longhorn completed an installment sale of the pipeline during the third quarter of 2006. The sale of the pipeline did not impact these ongoing payments which are recognized as income when received.

Additional Business Segment Information

Our ongoing business segments are accounted for as continuing operations in the accompanying financial statements and notes to financial statements included in Part II.

Operations related to certain assets in "Discontinued Operations" have been reclassified from their traditional business segment to "Discontinued Operations" in the accompanying financial statements and notes to financial statements included in Part II.

Our corporate parent company performs certain management, legal, financial, tax, consultative, information technology, administrative and other services for our subsidiaries.

Our corporate parent company’s principal sources of cash are from external financings, dividends and advances from our subsidiaries, investments, payments by subsidiaries for services rendered, sales of master partnership units to the public, interest payments from subsidiaries on cash advances and net proceeds from asset sales. The amount of dividends available to us from subsidiaries largely depends upon each subsidiary’s earnings and operating capital requirements. The terms of certain of our subsidiaries’ borrowing arrangements limit the transfer of funds to our corporate parent.

We believe that we have adequate sources and availability of raw materials and commodities for existing and anticipated business needs. In support of our energy commodity activities, primarily conducted through Gas Marketing Services, our counterparties require us to provide various forms of credit support such as margin, adequate assurance amounts and pre-payments for gas supplies. Our pipeline systems are all regulated in various ways resulting in the financial return on the investments made in the systems being limited to standards permitted by the regulatory agencies. Each of the pipeline systems has ongoing capital requirements for efficiency and mandatory improvements, with expansion opportunities also necessitating periodic capital outlays.

REGULATORY MATTERS

Exploration & Production. Our Exploration & Production business is subject to various federal, state and local laws and regulations on taxation and payment of royalties, and the development, production and marketing of oil and gas, and environmental and safety matters. Many laws and regulations require drilling permits and govern the spacing of wells, rates of production, water discharge, prevention of waste and other matters. Such laws and regulations have increased the costs of planning, designing, drilling, installing, operating and abandoning our oil and gas wells and other facilities. In addition, these laws and regulations, and any others that are passed by the jurisdictions where we have production, could limit the total number of wells drilled or the allowable production from successful wells, which could limit our reserves.

Gas Pipeline. Gas Pipeline's interstate transmission and storage activities are subject to FERC regulation under the Natural Gas Act of 1938 (NGA) and under the Natural Gas Policy Act of 1978, and, as such, its rates and charges for the transportation of natural gas in interstate commerce, its accounting, and the extension, enlargement or abandonment of its jurisdictional facilities, among other things, are subject to regulation. Each gas pipeline company holds certificates of public convenience and necessity issued by the FERC authorizing ownership and operation of all pipelines, facilities and properties for which certificates are required under the NGA. Each gas pipeline company is also subject to the Natural Gas Pipeline Safety Act of 1968, as amended, which regulates safety requirements in the design, construction, operation and maintenance of interstate natural gas transmission facilities. FERC Standards of Conduct govern how our interstate pipelines communicate and do business with their marketing affiliates. Among other things, the Standards of Conduct require that interstate pipelines not operate their systems to preferentially benefit their marketing affiliates.

Each of our interstate natural gas pipeline companies establishes its rates primarily through the FERC's ratemaking process. Key determinants in the ratemaking process are:

- costs of providing service, including depreciation expense;
- allowed rate of return, including the equity component of the capital structure and related income taxes;
- volume throughput assumptions.

The allowed rate of return is determined in each rate case. Rate design and the allocation of costs between the demand and commodity rates also impact profitability. As a result of these proceedings, certain revenues previously collected may be subject to refund.

Midstream. For our Midstream segment, onshore gathering is subject to regulation by states in which we operate and offshore gathering is subject to the Outer Continental Shelf Lands Act (OCSLA). Of the states where Midstream gathers gas, currently only Texas actively regulates gathering activities. Texas regulates gathering primarily through complaint mechanisms under which the state commission may resolve disputes involving an individual gathering arrangement. Although gathering facilities located offshore are not subject to the NGA (although offshore transmission pipelines may be), some controversy exists as to how the FERC should determine whether offshore facilities function as gathering. These issues are currently before the FERC. Most gathering facilities offshore are subject to the OCSLA, which provides in part that outer continental shelf pipelines "must provide open and nondiscriminatory access to both owner and non-owner shippers."

Midstream also owns interests in and operates two offshore transmission pipelines that are regulated by the FERC because they are deemed to transport gas in interstate commerce. Black Marlin Pipeline Company provides transportation service for offshore Texas production in the High Island area and redelivers that gas to intrastate pipeline interconnects near Texas City. Discovery provides transportation service for offshore Louisiana production from the South Timbalier, Grand Isle, Ewing Bank and Green Canyon (deepwater) areas to an onshore processing facility and downstream interconnect points with major interstate pipelines. FERC regulation requires all terms and conditions of service, including the rates charged, to be filed with and approved by the FERC before any changes can go into effect. In 2007, Black Marlin filed and settled a major rate change application before the FERC resulting in increased rates for service. In November 2007, Discovery filed a settlement in lieu of a rate change filing that if approved would increase its rates for service.

Our remaining Midstream Canadian assets are regulated by the Alberta Energy & Utilities Board (AEUB) and Alberta Environment. The regulatory system for the Alberta oil and gas industry incorporates a large measure of self-regulation, providing that licensed operators are held responsible for ensuring that their operations are conducted in accordance with all provincial regulatory requirements. For situations in which non-compliance with the applicable regulations is at issue, the AEUB and Alberta Environment have implemented an enforcement process with escalating consequences.

Gas Marketing Services. Our Gas Marketing business is subject to a variety of laws and regulations at the local, state and federal levels, including the FERC and the Commodity Futures Trading Commission regulations. In addition, natural gas markets continue to be subject to numerous and wide-ranging federal and state regulatory proceedings and investigations. We are also subject to various federal and state actions and investigations regarding, among other things, market structure, behavior of market participants, market prices, and reporting to trade publications. We may be liable for refunds and other damages and penalties as a result of ongoing actions and investigations. The outcome of these matters could affect our creditworthiness and ability to perform contractual obligations as well as other market participants' creditworthiness and ability to perform contractual obligations to us.

See Note 15 of our Notes to Consolidated Financial Statements for further details on our regulatory matters.

ENVIRONMENTAL MATTERS

Our generation facilities, processing facilities, natural gas pipelines, and exploration and production operations are subject to federal environmental laws and regulations as well as the state and tribal laws and regulations adopted by the jurisdictions in which we operate. We could incur liability to governments or third parties for any unlawful discharge of oil, gas or other pollutants into the air, soil, or water, as well as liability for clean up costs. Materials could be released into the environment in several ways including, but not limited to:

- from a well or drilling equipment at a drill site;
- leakage from gathering systems, pipelines, transportation facilities and storage tanks;
- damage to oil and gas wells resulting from accidents during normal operations;
- blowouts, cratering and explosions.

Because the requirements imposed by environmental laws and regulations are frequently changed, we cannot assure you that laws and regulations enacted in the future, including changes to existing laws and regulations, will not adversely affect our business. In addition we may be liable for environmental damage caused by former operators of our properties.

We believe compliance with environmental laws and regulations will not have a material adverse effect on capital expenditures, earnings or competitive position. However, environmental laws and regulations could affect our business in various ways from time to time, including incurring capital and maintenance expenditures, fines and penalties, and creating the need to seek relief from the FERC for rate increases to recover the costs of certain capital expenditures and operation and maintenance expenses.

For a discussion of specific environmental issues, see "Environmental" under Management's Discussion and Analysis of Financial Condition and Results of Operations and "Environmental Matters" in Note 15 of our Notes to Consolidated Financial Statements.

COMPETITION

Exploration & Production. Our Exploration & Production segment competes with other oil and gas concerns, including major and independent oil and gas companies in the development, production and marketing of natural gas. We compete in areas such as acquisition of oil and gas properties and obtaining necessary equipment, supplies and services. We also compete in recruiting and retaining skilled employees.

Gas Pipeline. The natural gas industry has undergone significant change over the past two decades. A highly-liquid competitive commodity market in natural gas and increasingly competitive markets for natural gas services, including competitive secondary markets in pipeline capacity, have developed. As a result, pipeline capacity is being used more efficiently, and peaking and storage services are increasingly effective substitutes for annual pipeline capacity.

Local distribution company (LDC) and electric industry restructuring by states have affected pipeline markets. Pipeline operators are increasingly challenged to accommodate the flexibility demanded by customers and allowed under tariffs, but the changes implemented at the state level have not required renegotiation of LDC contracts. The state plans have in some cases discouraged LDCs from signing long-term contracts for new capacity.

Several states are considering re-regulation and extending price caps because many regulators and legislators believe that deregulation has not worked. States are in the process of developing new energy plans that may require utilities to encourage energy saving measures and diversify their energy supplies to include renewable sources. This could lower the growth of gas demand.

These factors have increased the risk that customers will reduce their contractual commitments for pipeline capacity. Future utilization of pipeline capacity will also depend on competition from LNG imported into markets and new pipelines from the Rockies and other new producing areas, many of which are utilizing master limited partnership structures with a lower cost of capital, and on growth of natural gas demand.

Midstream. In our Midstream segment, we face regional competition with varying competitive factors in each basin. Our gathering and processing business competes with other midstream companies, interstate and intrastate pipelines, producers and independent gatherers and processors. We primarily compete with five to ten companies across all basins in which we provide services. Numerous factors impact any given customer's choice of a gathering or processing services provider, including rate, location, term, timeliness of services to be provided, pressure obligations and contract structure. We also compete in recruiting and retaining skilled employees. In 2005 we formed WPZ to help compete against other master limited partnerships for midstream projects. By virtue of the master limited partnership structure, WPZ provides us with an alternative and low-cost source of capital. We expect the alternative, low-cost capital will allow WPZ to compete favorably from a cost of capital perspective with other MLPs when pursuing acquisition opportunities of gathering and processing assets.

Gas Marketing Services. In our Gas Marketing Services segment, we compete directly with large independent energy marketers, marketing affiliates of regulated pipelines and utilities, and natural gas producers. We also compete with brokerage houses, energy hedge funds and other energy-based companies offering similar services.

EMPLOYEES

At February 1, 2008, we had approximately 4,319 full-time employees including 898 at the corporate level, 681 at Exploration & Production, 1,732 at Gas Pipeline, 984 at Midstream, and 24 at Gas Marketing Services. None of our employees are represented by unions or covered by collective bargaining agreements.

FINANCIAL INFORMATION ABOUT GEOGRAPHIC AREAS

See Note 17 of our Notes to Consolidated Financial Statements for amounts of revenues during the last three fiscal years from external customers attributable to the United States and all foreign countries. Also see Note 17 of our Notes to Consolidated Financial Statements for information relating to long-lived assets during the last three fiscal years, located in the United States and all foreign countries.

Item 1A. *Risk Factors*

FORWARD-LOOKING STATEMENTS/RISK FACTORS AND CAUTIONARY STATEMENT FOR PURPOSES OF THE "SAFE HARBOR" PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

Certain matters contained in this report include "forward-looking statements" within the meaning of section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. These statements discuss our expected future results based on current and pending business operations. We make those forward-looking statements in reliance on the safe harbor protections provided under the Private Securities Litigation Reform Act of 1995.

All statements, other than statements of historical facts, included in this report which address activities, events or developments that we expect, believe or anticipate will exist or may occur in the future, are forward-looking statements. Forward-looking statements can be identified by various forms of words such as "anticipates," "believes," "could," "may," "should," "continues," "estimates," "expects," "forecasts," "might," "planned," "potential," "projects," "scheduled" or similar expressions. These forward-looking statements include, among others, statements regarding:

- amounts and nature of future capital expenditures;
- expansion and growth of our business and operations;
- business strategy;
- estimates of proved gas and oil reserves;
- reserve potential;
- development drilling potential;
- cash flow from operations or results of operations;
- seasonality of certain business segments;
- natural gas and natural gas liquids prices and demand.

Forward-looking statements are based on numerous assumptions, uncertainties and risks that could cause future events or results to be materially different from those stated or implied in this document. Many of the factors that will determine these results are beyond our ability to control or project. Specific factors which could cause actual results to differ from those in the forward-looking statements include:

- availability of supplies (including the uncertainties inherent in assessing and estimating future natural gas reserves), market demand, volatility of prices, and increased costs of capital;
- inflation, interest rates, fluctuation in foreign exchange, and general economic conditions;
- the strength and financial resources of our competitors;
- development of alternative energy sources;
- the impact of operational and development hazards;
- costs of, changes in, or the results of laws, government regulations including proposed climate change legislation, environmental liabilities, litigation, and rate proceedings;
- changes in the current geopolitical situation;
- risks related to strategy and financing, including restrictions stemming from our debt agreements and future changes in our credit ratings;
- risks associated with future weather conditions;
- acts of terrorism.

Given the uncertainties and risk factors that could cause our actual results to differ materially from those contained in any forward-looking statement, we caution investors not to unduly rely on our forward-looking statements. We disclaim any obligations to and do not intend to update the above list to announce publicly the result of any revisions to any of the forward-looking statements to reflect future events or developments.

In addition to causing our actual results to differ, the factors listed above and referred to below may cause our intentions to change from those statements of intention set forth in this report. Such changes in our intentions may also cause our results to differ. We may change our intentions, at any time and without notice, based upon changes in such factors, our assumptions, or otherwise.

Because forward-looking statements involve risks and uncertainties, we caution that there are important factors, in addition to those listed above, that may cause actual results to differ materially from those contained in the forward-looking statements. These factors include the following:

RISK FACTORS

You should carefully consider the following risk factors in addition to the other information in this report. Each of these factors could adversely affect our business, operating results, and financial condition as well as adversely affect the value of an investment in our securities.

Risks Inherent to our Industry and Business

The long-term financial condition of our natural gas transportation and midstream businesses is dependent on the continued availability of natural gas supplies in the supply basins that we access, demand for those supplies in our traditional markets, and market demand for natural gas.

The development of the additional natural gas reserves that are essential for our gas transportation and midstream businesses to thrive requires significant capital expenditures by others for exploration and development drilling and the installation of production, gathering, storage, transportation and other facilities that permit natural gas to be produced and delivered to our pipeline systems. Low prices for natural gas, regulatory limitations, or the lack of available capital for these projects could adversely affect the development and production of additional reserves, as well as gathering, storage, pipeline transportation and import and export of natural gas supplies, adversely impacting our ability to fill the capacities of our gathering, transportation and processing facilities. Additionally, in some cases, new LNG import facilities built near our markets could result in less demand for our gathering and transportation facilities.

Estimating reserves and future net revenues involves uncertainties. Negative revisions to reserve estimates and oil and gas price declines may lead to decreased earnings, losses or impairment of oil and gas assets, including related goodwill.

Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact manner. Reserves that are "proved reserves" are those estimated quantities of crude oil, natural gas, and natural gas liquids that geological and engineering data demonstrate with reasonable certainty are recoverable in future years from known reservoirs under existing economic and operating conditions, but should not be considered as a guarantee of results for future drilling projects.

The process relies on interpretations of available geological, geophysical, engineering and production data. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of developmental expenditures, including many factors beyond the control of the producer. The reserve data included in this report represent estimates. In addition, the estimates of future net revenues from our proved reserves and the present value of such estimates are based upon certain assumptions about future production levels, prices and costs that may not prove to be correct over time.

Quantities of proved reserves are estimated based on economic conditions in existence during the period of assessment. Changes to oil and gas prices in the markets for such commodities may have the impact of shortening the economic lives of certain fields because it becomes uneconomic to produce all recoverable reserves on such fields, which reduces proved property reserve estimates.

If negative revisions in the estimated quantities of proved reserves were to occur, it would have the effect of increasing the rates of depreciation, depletion and amortization on the affected properties, which would decrease earnings or result in losses through higher depreciation, depletion and amortization expense. The revisions may also be sufficient to trigger impairment losses on certain properties which would result in a further non-cash charge to earnings. The revisions could also possibly affect the evaluation of Exploration & Production's goodwill for impairment purposes.

Our past success rate for drilling projects and the historic performance of our exploration and production business is no predictor of future performance.

Our past success rate for drilling projects in 2007 should not be considered a predictor of future performance.

Performance of our exploration and production business is affected in part by factors beyond our control (any of which could cause the results of this business to decrease materially), such as:

- regulations and regulatory approvals;
- availability of capital for drilling projects which may be affected by other risk factors discussed in this report;
- cost-effective availability of drilling rigs and necessary equipment;
- availability of skilled labor;
- availability of cost-effective transportation for products;
- market risks (including price risks and competition) discussed in this report.

Our drilling, production, gathering, processing and transporting activities involve numerous risks that might result in accidents, and other operating risks and hazards.

Our operations are subject to all the risks and hazards typically associated with the development and exploration for, and the production and transportation of oil and gas. These operating risks include, but are not limited to:

- blowouts, cratering and explosions;
- uncontrollable flows of oil, natural gas or well fluids;
- fires;
- formations with abnormal pressures;
- pollution and other environmental risks;
- natural disasters.

In addition, there are inherent in our gas gathering, processing and transporting properties a variety of hazards and operating risks, such as leaks, spills, explosions and mechanical problems that could cause substantial financial losses. In addition, these risks could result in loss of human life, significant damage to property, environmental pollution, impairment of our operations and substantial losses to us. In accordance with customary industry practice, we maintain insurance against some, but not all, of these risks and losses, and only at levels we believe to be appropriate. The location of certain segments of our pipelines in or near populated areas, including residential areas, commercial business centers and industrial sites, could increase the level of damages resulting from these risks. In spite of our precautions, an event could cause considerable harm to people or property, and could have a material adverse effect on our financial condition, particularly if the event is not fully covered by insurance. Accidents or other operating risks could further result in loss of service available to our customers. Such circumstances could materially impact our ability to meet contractual obligations and retain customers, with a resulting impact on our results of operations.

Costs of environmental liabilities and complying with existing and future environmental regulations could exceed our current expectations.

Our operations are subject to extensive environmental regulation pursuant to a variety of federal, provincial, state and municipal laws and regulations. Such laws and regulations impose, among other things, restrictions, liabilities and obligations in connection with the generation, handling, use, storage, extraction, transportation, treatment and disposal of hazardous substances and wastes, in connection with spills, releases and emissions of various substances into the environment, and in connection with the operation, maintenance, abandonment and reclamation of our facilities.

Compliance with environmental laws requires significant expenditures, including for clean up costs and damages arising out of contaminated properties. In addition, the possible failure to comply with environmental laws and regulations might result in the imposition of fines and penalties. We are generally responsible for all liabilities associated with the environmental condition of our facilities and assets, whether acquired or developed, regardless of when the liabilities arose and whether they are known or unknown. In connection with certain acquisitions and divestitures, we could acquire, or be required to provide indemnification against, environmental liabilities that could expose us to material losses, which may not be covered by insurance. In addition, the steps we could be required to take to bring certain facilities into compliance could be prohibitively expensive, and we might be required to shut down, divest or alter the operation of those facilities, which might cause us to incur losses. Although we do not expect that the costs of complying with current environmental laws will have a material adverse effect on our financial condition or results of operations, no assurance can be given that the costs of complying with environmental laws in the future will not have such an effect.

Changes in federal laws or regulations could reduce the availability or increase the cost of our interstate pipeline capacity or gas supply, and thereby reduce our earnings. Congress and certain states have for some time been considering various forms of legislation related to greenhouse gas emissions. There is a possibility that, when and if enacted, the final form of such legislation could increase our costs of compliance with environmental laws.

We make assumptions and develop expectations about possible expenditures related to environmental conditions based on current laws and regulations and current interpretations of those laws and regulations. If the interpretation of laws or regulations, or the laws and regulations themselves, change, our assumptions may change. Our regulatory rate structure and our contracts with customers might not necessarily allow us to recover capital costs we incur to comply with the new environmental regulations. Also, we might not be able to obtain or maintain from time to time all required environmental regulatory approvals for certain development projects. If there is a delay in obtaining any required environmental regulatory approvals or if we fail to obtain and comply with them, the operation of our facilities could be prevented or become subject to additional costs, resulting in potentially material adverse consequences to our results of operations.

Our operating results for certain segments of our business might fluctuate on a seasonal and quarterly basis.

Revenues from certain segments of our business can have seasonal characteristics. In many parts of the country, demand for natural gas and other fuels peaks during the winter. As a result, our overall operating results in the future might fluctuate substantially on a seasonal basis. Demand for natural gas and other fuels could vary significantly from our expectations depending on the nature and location of our facilities and pipeline systems and the terms of our natural gas transportation arrangements relative to demand created by unusual weather patterns. Additionally, changes in the price of natural gas could benefit one of our business units, but disadvantage another. For example, our Exploration & Production business may benefit from higher natural gas prices, and Midstream, which uses gas as a feedstock, may not.

Risks Related to the Current Geopolitical Situation

Our investments and projects located outside of the United States expose us to risks related to the laws of other countries, and the taxes, economic conditions, fluctuations in currency rates, political conditions and policies of foreign governments. These risks might delay or reduce our realization of value from our international projects.

We currently own and might acquire and/or dispose of material energy-related investments and projects outside the United States. The economic and political conditions in certain countries where we have interests or in which we might explore development, acquisition or investment opportunities present risks of delays in construction and interruption of business, as well as risks of war, expropriation, nationalization, renegotiation, trade sanctions or nullification of existing contracts and changes in law or tax policy, that are greater than in the United States. The uncertainty of the legal environment in certain foreign countries in which we develop or acquire projects or make investments could make it more difficult to obtain non-recourse project financing or other financing on suitable terms, could adversely affect the ability of certain customers to honor their obligations with respect to such projects or investments and could impair our ability to enforce our rights under agreements relating to such projects or investments. Recent events in certain South American countries, particularly the continued threat of nationalization of certain energy-related assets in Venezuela, could have a material negative impact on our results of operations. We may not receive adequate compensation, or any compensation, if our assets in Venezuela are nationalized.

Operations and investments in foreign countries also can present currency exchange rate and convertibility, inflation and repatriation risk. In certain situations under which we develop or acquire projects or make investments, economic and monetary conditions and other factors could affect our ability to convert to U.S. dollars our earnings denominated in foreign currencies. In addition, risk from fluctuations in currency exchange rates can arise when our foreign subsidiaries expend or borrow funds in one type of currency, but receive revenue in another. In such cases, an adverse change in exchange rates can reduce our ability to meet expenses, including debt service obligations. We may or may not put contracts in place designed to mitigate our foreign currency exchange risks. We have some exposures that are not hedged and which could result in losses or volatility in our results of operations.

Risks Related to Strategy and Financing

Our debt agreements impose restrictions on us that may adversely affect our ability to operate our business.

Certain of our debt agreements contain covenants that restrict or limit among other things, our ability to create liens, sell assets, make certain distributions, repurchase equity and incur additional debt. In addition, our debt agreements contain, and those we enter into in the future may contain, financial covenants and other limitations with which we will need to comply. Our ability to comply with these covenants may be affected by many events beyond our control, and we cannot assure you that our future operating results will be sufficient to comply with the covenants or, in the event of a default under any of our debt agreements, to remedy that default.

Our failure to comply with the covenants in our debt agreements and other related transactional documents could result in events of default. Upon the occurrence of such an event of default, the lenders could elect to declare all amounts outstanding under a particular facility to be immediately due and payable and terminate all commitments, if any, to extend further credit. An event of default or an acceleration under one debt agreement could cause a cross-default or cross-acceleration of another debt agreement. Such a cross-default or cross-acceleration could have a wider impact on our liquidity than might otherwise arise from a default or acceleration of a single debt instrument. If an event of default occurs, or if other debt agreements cross-default, and the lenders under the affected debt agreements accelerate the maturity of any loans or other debt outstanding to us, we may not have sufficient liquidity to repay amounts outstanding under such debt agreements.

A downgrade of our current credit ratings could impact our costs of doing business in certain ways and maintaining current credit ratings is within the control of independent third parties.

A downgrade of our credit rating might increase our cost of borrowing. Our ability to access capital markets could also be limited by a downgrade of our credit rating and other disruptions. Such disruptions could include:

- economic downturns;
- deteriorating capital market conditions generally;
- declining market prices for natural gas, natural gas liquids and other commodities;
- terrorist attacks or threatened attacks on our facilities or those of other energy companies;
- the overall health of the energy industry, including the bankruptcy or insolvency of other companies.

Credit rating agencies perform independent analysis when assigning credit ratings. Given the significant changes in capital markets and the energy industry over the last few years, credit rating agencies continue to review the criteria for attaining investment grade ratings and make changes to those criteria from time to time. Our corporate family credit rating and the credit ratings of Transco and Northwest Pipeline were raised to investment grade in 2007 by Standard & Poor's, Moody's Corporation, and Fitch Ratings, Ltd., and our senior unsecured debt ratings were raised to investment grade by Moody's and Fitch. No assurance can be given that the credit rating agencies will assign us investment grade ratings even if we meet or exceed their criteria for investment grade ratios or that our senior unsecured debt rating will be raised to investment grade by all of the credit rating agencies.

Prices for natural gas liquids, natural gas and other commodities are volatile and this volatility could adversely affect our financial results, cash flows, access to capital and ability to maintain existing businesses.

Our revenues, operating results, future rate of growth and the value of certain segments of our businesses depend primarily upon the prices we receive for natural gas liquids, natural gas, or other commodities, and the differences between prices of these commodities. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow money or raise additional capital.

The markets for natural gas liquids, natural gas and other commodities are likely to continue to be volatile. Wide fluctuations in prices might result from relatively minor changes in the supply of and demand for these commodities, market uncertainty and other factors that are beyond our control, including:

- worldwide and domestic supplies of and demand for natural gas, natural gas liquids, petroleum, and related commodities;
- turmoil in the Middle East and other producing regions;
- the activities of the Organization of Petroleum Exporting Countries;
- terrorist attacks on production or transportation assets;
- weather conditions;
- the level of consumer demand;
- the price and availability of other types of fuels;
- the availability of pipeline capacity;
- supply disruptions, including plant outages and transportation disruptions;
- the price and level of foreign imports;
- domestic and foreign governmental regulations and taxes;
- volatility in the natural gas markets;
- the overall economic environment;
- the credit of participants in the markets where products are bought and sold;
- the adoption of regulations or legislation relating to climate change.

We might not be able to successfully manage the risks associated with selling and marketing products in the wholesale energy markets.

Our portfolio of derivative and other energy contracts consists of wholesale contracts to buy and sell commodities, including contracts for natural gas, natural gas liquids and other commodities that are settled by the delivery of the commodity or cash throughout the United States. If the values of these contracts change in a direction or manner that we do not anticipate or cannot manage, it could negatively affect our results of operations. In the past, certain marketing and trading companies have experienced severe financial problems due to price volatility in the energy commodity markets. In certain instances this volatility has caused companies to be unable to deliver energy commodities that they had guaranteed under contract. If such a delivery failure were to occur in one of our contracts, we might incur additional losses to the extent of amounts, if any, already paid to, or received from, counterparties. In addition, in our businesses, we often extend credit to our counterparties. Despite performing credit analysis prior to extending credit, we are exposed to the risk that we might not be able to collect amounts

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owed to us. If the counterparty to such a transaction fails to perform and any collateral that secures our counterparty's obligation is inadequate, we will suffer a loss.

If we are unable to perform under our energy agreements, we could be required to pay damages. These damages generally would be based on the difference between the market price to acquire replacement energy or energy services and the relevant contract price. Depending on price volatility in the wholesale energy markets, such damages could be significant.

Risks Related to Regulations that Affect our Industry

Our natural gas sales, transmission, and storage operations are subject to government regulations and rate proceedings that could have an adverse impact on our results of operations.

Our interstate natural gas sales, transportation, and storage operations conducted through our Gas Pipelines business are subject to the FERC's rules and regulations in accordance with the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. The FERC's regulatory authority extends to:

- transportation and sale for resale of natural gas in interstate commerce;
- rates and charges;
- construction;
- acquisition, extension or abandonment of services or facilities;
- accounts and records;
- depreciation and amortization policies;
- operating terms and conditions of service.

Regulatory actions in these areas can affect our business in many ways, including decreasing tariff rates and revenues, decreasing volumes in our pipelines, increasing our costs and otherwise altering the profitability of our business. Regulatory decisions could also affect our costs for compression, processing and dehydration of natural gas, which could have a negative effect on our results of operations.

The FERC has taken certain actions to strengthen market forces in the natural gas pipeline industry that have led to increased competition throughout the industry. In a number of key markets, interstate pipelines are now facing competitive pressure from other major pipeline systems, enabling local distribution companies and end users to choose a transportation provider based on considerations other than location.

Competition in the markets in which we operate may adversely affect our results of operations.

We have numerous competitors in all aspects of our businesses, and additional competitors may enter our markets. Other companies with which we compete may be able to respond more quickly to new laws or regulations or emerging technologies, or to devote greater resources to the construction, expansion or refurbishment of their facilities than we can. In addition, current or potential competitors may make strategic acquisitions or have greater financial resources than we do, which could affect our ability to make investments or acquisitions. There can be no assurance that we will be able to compete successfully against current and future competitors and any failure to do so could have a material adverse effect on our businesses and results of operations.

Expiration of firm transportation agreements.

A substantial portion of the operating revenues of our Gas Pipelines are generated through firm transportation agreements that expire periodically and must be renegotiated and extended or replaced. We cannot give any assurance as to whether any of these agreements will be extended or replaced or that the terms of any renegotiated agreements will be as favorable as the existing agreements. Upon the expiration of these agreements, should customers turn back or substantially reduce their commitments, we could experience a negative effect to our results of operations.

Our revenues might decrease if we are unable to gain adequate, reliable and affordable access to transportation and distribution assets.

We depend on transportation and distribution facilities owned and operated by utilities and other energy companies to deliver the commodities we buy and sell in the wholesale market. If transportation is disrupted, if capacity is inadequate, or if credit requirements or rates of such utilities or energy companies are increased, our ability to sell and deliver products might be hindered. Further, although there are laws and regulations designed to encourage competition in wholesale market transactions, some companies may fail to provide fair and equal access to their transportation systems or may not provide sufficient transportation capacity for other market participants.

Our businesses are subject to complex government regulations. The operation of our businesses might be adversely affected by changes in these regulations or in their interpretation or implementation, or the introduction of new laws or regulations applicable to our businesses or our customers.

Existing regulations might be revised or reinterpreted, new laws and regulations might be adopted or become applicable to us, our facilities or our customers, and future changes in laws and regulations might have a detrimental effect on our business. Over the past few years, certain restructured energy markets have experienced supply problems and price volatility. In some of these markets, proposals have been made by governmental agencies and other interested parties to re-regulate areas of these markets which have previously been deregulated. Various forms of market controls and limitations including price caps and bid caps have already been implemented and new controls and market restructuring proposals are in various stages of development, consideration and implementation. We cannot assure you that changes in market structure and regulation will not adversely affect our business and results of operations. We also cannot assure you that other proposals to re-regulate will not be made or that legislative or other attention to these restructured energy markets will not cause the deregulation process to be delayed or reversed or otherwise adversely affect our business and results of operations.

The outcome of a pending rate case to set the rates we can charge customers on Transco's pipeline might result in rates that do not provide an adequate return on the capital we have invested in the Transco pipeline.

We have a pending rate case with the FERC to request changes to the rates we charge on Transco. We have sought FERC approval of a settlement of the significant issues in the rate case but until FERC approves the settlement, the outcome of the rate case remains uncertain. There is a risk that rates set by the FERC will lower our return on the capital we have invested in our assets or might not be adequate to recover increases in operating costs. There is also the risk that higher rates will cause our customers to look for alternative ways to transport their natural gas.

Legal and regulatory proceedings and investigations relating to the energy industry and capital markets have adversely affected our business and may continue to do so.

Public and regulatory scrutiny of the energy industry and of the capital markets has resulted in increased regulation being either proposed or implemented. Such scrutiny has also resulted in various inquiries, investigations and court proceedings in which we are a named defendant. Both the shippers on our pipelines and regulators have rights to challenge the rates we charge under certain circumstances. Any successful challenge could materially affect our results of operations.

Certain inquiries, investigations and court proceedings are ongoing and continue to adversely affect our business as a whole. We might see these adverse effects continue as a result of the uncertainty of these ongoing inquiries and proceedings, or additional inquiries and proceedings by federal or state regulatory agencies or private plaintiffs. In addition, we cannot predict the outcome of any of these inquiries or whether these inquiries will lead to additional legal proceedings against us, civil or criminal fines or penalties, or other regulatory action, including legislation, which might be materially adverse to the operation of our business and our revenues and net income or increase our operating costs in other ways. Current legal proceedings or other matters against us arising out of our ongoing and discontinued operations including environmental matters, disputes over gas measurement, royalty payments, shareholder class action suits, regulatory appeals and similar matters might result in adverse decisions against us. The result of such adverse decisions, either individually or in the aggregate, could be material and may not be covered fully or at all by insurance.

Risks Related to Accounting Standards

Potential changes in accounting standards might cause us to revise our financial results and disclosures in the future, which might change the way analysts measure our business or financial performance.

Regulators and legislators continue to take a renewed look at accounting practices, financial disclosures, companies' relationships with their independent registered public accounting firms, and retirement plan practices. We cannot predict the ultimate impact of any future changes in accounting regulations or practices in general with respect to public companies or the energy industry or in our operations specifically.

In addition, the Financial Accounting Standards Board (FASB) or the SEC could enact new accounting standards that might impact how we are required to record revenues, expenses, assets, liabilities and equity.

Risks Related to Market Volatility and Risk Measurement and Hedging Activities

Our risk measurement and hedging activities might not be effective and could increase the volatility of our results.

Although we have systems in place that use various methodologies to quantify commodity price risk associated with our businesses, these systems might not always be followed or might not always be effective. Further, such systems do not in themselves manage risk, particularly risks outside of our control, and adverse changes in energy commodity market prices, volatility, adverse correlation of commodity prices, the liquidity of markets, changes in interest rates and other risks discussed in this report might still adversely affect our earnings, cash flows and balance sheet under applicable accounting rules, even if risks have been identified.

In an effort to manage our financial exposure related to commodity price and market fluctuations, we have entered into contracts to hedge certain risks associated with our assets and operations. In these hedging activities, we have used fixed-price, forward, physical purchase and sales contracts, futures, financial swaps and option contracts traded in the over-the-counter markets or on exchanges. Nevertheless, no single hedging arrangement can adequately address all risks present in a given contract. For example, a forward contract that would be effective in hedging commodity price volatility risks would not hedge the contract's counterparty credit or performance risk. Therefore, unhedged risks will always continue to exist. While we attempt to manage counterparty credit risk within guidelines established by our credit policy, we may not be able to successfully manage all credit risk and as such, future cash flows and results of operations could be impacted by counterparty default.

Our use of hedging arrangements through which we attempt to reduce the economic risk of our participation in commodity markets could result in increased volatility of our reported results. Changes in the fair values (gains and losses) of derivatives that qualify as hedges under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," (SFAS 133) to the extent that such hedges are not fully effective in offsetting changes to the value of the hedged commodity, as well as changes in the fair value of derivatives that do not qualify or have not been designated as hedges under SFAS 133, must be recorded in our income. This creates the risk of volatility in earnings even if no economic impact to the Company has occurred during the applicable period.

The impact of changes in market prices for natural gas on the average gas prices received by us may be reduced based on the level of our hedging strategies. These hedging arrangements may limit our potential gains if the market prices for natural gas were to rise substantially over the price established by the hedge. In addition, our hedging arrangements expose us to the risk of financial loss in certain circumstances, including instances in which:

- production is less than expected;
- the hedging instrument is not perfectly effective in mitigating the risk being hedged;
- the counterparties to our hedging arrangements fail to honor their financial commitments.

Risks Related to Employees, Outsourcing of Non-Core Support Activities, and Technology

Institutional knowledge residing with current employees nearing retirement eligibility might not be adequately preserved.

In certain segments of our business, institutional knowledge resides with employees who have many years of service. As these employees reach retirement age, we may not be able to replace them with employees of comparable knowledge and experience. In addition, we may not be able to retain or recruit other qualified individuals and our efforts at knowledge transfer could be inadequate. If knowledge transfer, recruiting and retention efforts are inadequate, access to significant amounts of internal historical knowledge and expertise could become unavailable to us.

Failure of or disruptions to our outsourcing relationships might negatively impact our ability to conduct our business.

Some studies indicate a high failure rate of outsourcing relationships. Although we have taken steps to build a cooperative and mutually beneficial relationship with our outsourcing providers and to closely monitor their performance, a deterioration in the timeliness or quality of the services performed by the outsourcing providers or a failure of all or part of these relationships could lead to loss of institutional knowledge and interruption of services necessary for us to be able to conduct our business.

Certain of our accounting, information technology, application development, and help desk services are currently provided by an outsourcing provider from service centers outside of the United States. The economic and political conditions in certain countries from which our outsourcing providers may provide services to us present similar risks of business operations located outside of the United States previously discussed, including risks of interruption of business, war, expropriation, nationalization, renegotiation, trade sanctions or nullification of existing contracts and changes in law or tax policy, that are greater than in the United States.

Risks Related to Weather, other Natural Phenomena and Business Disruption

Our assets and operations can be adversely affected by weather and other natural phenomena.

Our assets and operations, including those located offshore, can be adversely affected by hurricanes, earthquakes, tornadoes and other natural phenomena and weather conditions including extreme temperatures, making it more difficult for us to realize the historic rates of return associated with these assets and operations.

Acts of terrorism could have a material adverse effect on our financial condition, results of operations and cash flows.

Our assets and the assets of our customers and others may be targets of terrorist activities that could disrupt our business or cause significant harm to our operations, such as full or partial disruption to our ability to produce, process, transport or distribute natural gas, natural gas liquids or other commodities. Acts of terrorism as well as events occurring in response to or in connection with acts of terrorism could cause environmental repercussions that could result in a significant decrease in revenues or significant reconstruction or remediation costs, which could have a material adverse effect on our financial condition, results of operations and cash flows.

Item 1B. ***Unresolved Staff Comments***

None.

Item 2. ***Properties***

We own property in 30 states plus the District of Columbia in the United States and in Argentina, Canada and Venezuela.

Gas Marketing's primary assets are its term contracts, related systems and technological support. In our Gas Pipeline and Midstream segments, we generally own our facilities, although a substantial portion of our pipeline and gathering facilities is constructed and maintained pursuant to rights-of-way, easements, permits, licenses or consents on and across properties owned by others. In our Exploration & Production segment, the majority of our ownership interest in exploration and production properties is held as working interests in oil and gas leaseholds.

Item 3. ***Legal Proceedings***

The information called for by this item is provided in Note 15 of the Notes to Consolidated Financial Statements of this report, which information is incorporated by reference into this item.

Item 4. ***Submission of Matters to a Vote of Security Holders***

None.

Executive Officers of the Registrant

The name, age, period of service, and title of each of our executive officers as of February 21, 2008, are listed below.

Alan S. Armstrong	Senior Vice President, Midstream Age: 45 Position held since February 2002. From 1999 to February 2002, Mr. Armstrong was Vice President, Gathering and Processing for Midstream. From 1998 to 1999 he was Vice President, Commercial Development for Midstream. Mr. Armstrong serves as a director of Williams Partners GP LLC, the general partner of Williams Partners L.P.
James J. Bender	Senior Vice President and General Counsel Age 51 Position held since December 2002. Prior to joining us, Mr. Bender was Senior Vice President and General Counsel with NRG Energy, Inc., a position held since June 2000, prior to which he was Vice President, General Counsel and Secretary of NRG Energy Inc. since June 1997. NRG Energy, Inc. filed a voluntary bankruptcy petition during 2003 and its plan of reorganization was approved in December 2003.
Donald R. Chappel	Senior Vice President and Chief Financial Officer Age: 56 Position held since April 2003. Prior to joining us, Mr. Chappel during 2000 founded and served as chief executive officer of a development business in Chicago, Illinois through April 2003, when he joined us. Mr. Chappel joined Waste Management, Inc. in 1987 and held various financial, administrative and operational leadership positions, including twice serving as chief financial officer, during 1997 and 1998 and most recently during 1999 through February 2000. Mr. Chappel serves as a director of Williams Partners GP LLC, the general partner of Williams Partners L.P., and as a director of Williams Pipeline GP LLC, the general partner of Williams Pipeline Partners L.P.

Ralph A. Hill	Senior Vice President, Exploration & Production Age: 48 Position held since December 1998. Mr. Hill was vice president of the exploration and production unit from 1993 to 1998 as well as Senior Vice President Petroleum Services from 1998 to 2003. Mr. Hill serves as a director of Apco Argentina Inc.
Michael P. Johnson, Sr.	Senior Vice President and Chief Administrative Officer Age: 60 Position held since May 2004. Mr. Johnson was named our Senior Vice President of Human Resources and Administration in April 1999. Prior to joining us in December 1998, he held officer level positions, such as Vice President of Human Resources, Vice President for Corporate People Strategies, and Vice President Human Resource Services, for Amoco Corporation from 1991 to 1998. Mr. Johnson serves as a director of Buffalo Wild Wings.
Steven J. Malcolm	Chairman of the Board, Chief Executive Officer and President Age: 59 Position held since September 2001. Mr. Malcolm was elected Chief Executive Officer of Williams in January 2002 and Chairman of the Board in May 2002. He was elected President and Chief Operating Officer in September 2001. Prior to that, he was our Executive Vice President from May 2001, President and Chief Executive Officer of our subsidiary Williams Energy Services, LLC, since December 1998 and the Senior Vice President and General Manager of our subsidiary, Williams Field Services Company, since November 1994. Mr. Malcolm serves as a director of Williams Partners GP LLC, the general partner of Williams Partners L.P., as a director of Williams Pipeline GP LLC, the general partner of Williams Pipeline Partners L.P., and as a director of Bank of Oklahoma, N.A.
Phillip D. Wright	Senior Vice President, Gas Pipeline Age: 52 Position held since January 2005. From October 2002 to January 2005, Mr. Wright served as Chief Restructuring Officer. From September 2001 to October 2002, Mr. Wright served as President and Chief Executive Officer of our subsidiary Williams Energy Services. From 1996 until September 2001, he was Senior Vice President, Enterprise Development and Planning for our energy services group. Mr. Wright has held various positions with us since 1989. Mr. Wright serves as a director of Williams Pipeline GP LLC, the general partner of Williams Pipeline Partners L.P.

PART II

Item 5. *Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities*

Our common stock is listed on the New York Stock Exchange under the symbol "WMB." At the close of business on February 21, 2008, we had approximately 11,153 holders of record of our common stock. The high and low closing sales price ranges (New York Stock Exchange composite transactions) and dividends declared by quarter for each of the past two years are as follows:

	2007			2006		
Quarter	**High**	**Low**	**Dividend**	**High**	**Low**	**Dividend**
1st	$28.94	$25.32	$ .09	$25.12	$19.49	$ .075
2nd	$32.43	$28.20	$ .10	$23.36	$20.33	$ .09
3rd	$34.72	$30.08	$ .10	$25.23	$22.51	$ .09
4th	$37.16	$33.68	$ .10	$27.95	$22.95	$ .09

Some of our subsidiaries' borrowing arrangements limit the transfer of funds to us. These terms have not impeded, nor are they expected to impede, our ability to pay dividends.

ISSUER PURCHASES OF EQUITY SECURITIES

Period	(a) Total Number of Shares Purchased	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs(1)	(d) Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs
October 1 — October 31, 2007	—	—	—	$ 766,140,266
November 1 — November 30, 2007	5,500,000	$ 34.54	5,500,000	$ 576,193,864
December 1 — December 31, 2007	2,946,200	$ 34.61	2,946,200	$ 474,228,219
Total	8,446,200	$ 34.56	8,446,200	$ 474,228,219

(1) We announced a stock repurchase program on July 20, 2007. Our board of directors has authorized the repurchase of up to $1 billion of the company's common stock. The stock repurchase program has no expiration date. We intend to purchase shares of our stock from time to time in open market transactions or through privately negotiated or structured transactions at our discretion, subject to market conditions and other factors.

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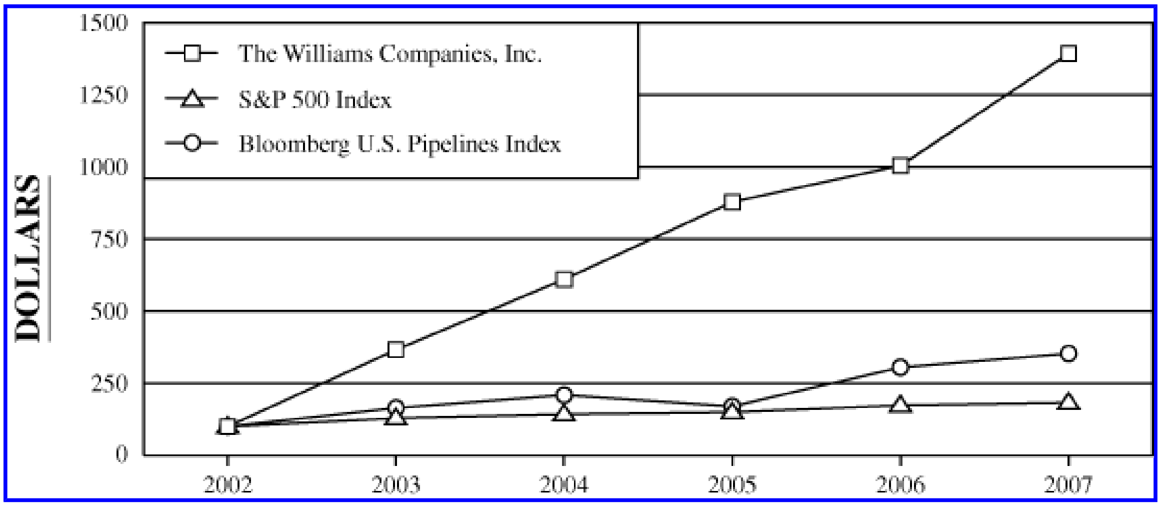
Performance Graph

Set forth below is a line graph comparing our cumulative total stockholder return on our common stock (assuming reinvestment of dividends) with the cumulative total return of the S&P 500 Stock Index and the Bloomberg U.S. Pipeline Index for the period of five fiscal years commencing January 1, 2003. The Bloomberg U.S. Pipeline Index is composed of El Paso, Equitable Resources, Questar, Oneok, TransCanada, Spectra Energy, Enbridge and Williams. The graph below assumes an investment of $100 at the beginning of the period.

Cumulative Total Shareholder Return



	2002	2003	2004	2005	2006	2007
The Williams Companies, Inc.	100.0	365.7	610.2	878.3	1,004.5	1,393.1
S&P 500 Index	100.0	128.7	142.7	149.7	173.3	182.8
Bloomberg U.S. Pipelines Index	100.0	164.1	208.8	269.7	304.9	352.7

Item 6. *Selected Financial Data*

The following financial data should be read in conjunction with Part II, Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations* and Part II, Item 8, *Financial Statements and Supplementary Data*.

	2007	2006	2005	2004	2003
	(Millions, except per-share amounts)				
Revenues(1)	$10,558	$ 9,376	$ 9,781	$ 8,408	$ 8,615
Income (loss) from continuing operations(2)	847	347	473	149	(248)
Income (loss) from discontinued operations(3)	143	(38)	(157)	15	517
Cumulative effect of change in accounting principles(4)	—	—	(2)	—	(761)
Diluted earnings (loss) per common share:					
Income (loss) from continuing operations	1.40	.57	.79	.28	(.54)
Income (loss) from discontinued operations	.23	(.06)	(.26)	.03	1.00
Cumulative effect of change in accounting principles	—	—	—	—	(1.47)
Total assets at December 31	25,061	25,402	29,443	23,993	27,022
Short-term notes payable and long-term debt due within one year at December 31	143	392	123	250	939
Long-term debt at December 31	7,757	7,622	7,591	7,712	11,040
Stockholders' equity at December 31	6,375	6,073	5,427	4,956	4,102
Cash dividends per common share	.39	.345	.25	.08	.04

(1) *Revenues* in 2003 includes approximately $117 million related to the correction of the accounting treatment previously applied to certain third-party derivative contracts during 2002 and 2001.

(2) See Note 4 of Notes to Consolidated Financial Statements for discussion of asset sales and other accruals in 2007, 2006, and 2005.

(3) See Note 2 of Notes to Consolidated Financial Statements for the analysis of the 2007, 2006 and 2005 income (loss) from discontinued operations. The discontinued operations results for 2004 and 2003 include the power business, the Canadian straddle plants, and the Alaska refining, retail, and pipeline operations. The 2003 discontinued operations results also include certain gas processing and natural gas liquid operations in Canada, a soda ash mining operation, a bio-energy operation, Texas Gas Transmission Corporation, certain natural gas production properties, our interest and investment in Williams Energy Partners, refining and marketing operations in the midsouth, and retail travel centers in the midsouth.

(4) The 2005 *cumulative effect of change in accounting principles* is due to implementation of Financial Accounting Standards Board (FASB) Interpretation No. 47 (FIN 47), "Accounting for Conditional Asset Retirement Obligations — an Interpretation of FASB statement No. 143 (SFAS 143)." The 2003 cumulative effect of change in accounting principles includes a $762 million charge related to the adoption of Emerging Issues Task Force Issue No. 02-3, slightly offset by $1 million related to the adoption of SFAS 143, "Accounting for Asset Retirement Obligations." The $762 million charge primarily consisted of the then fair value of power tolling, power load serving, gas transportation and gas storage contracts. The contracts were not derivatives and, therefore, were no longer reported at fair value.

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Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations*

General

We are primarily a natural gas company, engaged in finding, producing, gathering, processing, and transporting natural gas. Our operations are located principally in the United States and are organized into the following reporting segments: Exploration & Production, Gas Pipeline, Midstream Gas & Liquids (Midstream), and Gas Marketing Services. (See Note 1 of Notes to Consolidated Financial Statements for further discussion of reporting segments.)

Unless indicated otherwise, the following discussion of critical accounting estimates, discussion and analysis of results of operations and financial condition and liquidity relates to our current continuing operations and should be read in conjunction with the consolidated financial statements and notes thereto included in Part II Item 8 of this document.

Overview of 2007

Our plan for 2007 was focused on continued disciplined growth. Objectives and highlights of this plan included:

Objectives	Highlights
Continuing to improve both EVA® and segment profit.	2007 segment profit of almost $2.2 billion contributed to improving our EVA®.
Investing in our businesses in a way that improves EVA®, meets customer needs, and enhances our competitive position.	Total capital expenditures were approximately $2.8 billion, of which approximately $1.7 billion was invested in Exploration & Production.
Continuing to increase natural gas production and reserves in a responsible and efficient manner.	Exploration & Production increased its average daily domestic production by approximately 21 percent over last year while adding 776 billion cubic feet equivalent in net reserves during 2007. Total year-end 2007 proved domestic natural gas reserves are 4.14 trillion cubic feet equivalent, up 12 percent from year-end 2006 reserves. Additionally, we received 2007 industry awards, including the Bureau of Land Management's Best Management Practice Award.
Increasing the scale of our gathering and processing business in key growth basins.	We invested approximately $587 million in capital expenditures in Midstream, including Deepwater Gulf expansion projects and completion of our Opal gas processing facility expansion.
Successfully resolving rate cases to enable our Gas Pipeline segment to create additional value.	Increased rates were effective, subject to refund, on January 1, 2007, for Northwest Pipeline and on March 1, 2007, for Transco. In March, the FERC approved Northwest Pipeline's new rates. In November, Transco filed a stipulation and settlement agreement with the FERC, which is subject to final approval.

Our 2007 *income from continuing operations* increased to $847 million, as compared to $347 million in 2006. Our *net cash provided by operating activities* was $2.2 billion in 2007 compared to $1.9 billion in 2006. These comparative results reflect:

- Increased operating income at Midstream due primarily to increased natural gas liquid (NGL) margins;

- Increased operating income at Exploration & Production associated with increased production volumes and higher net realized average prices;
- Increased operating income at Gas Pipeline due primarily to new rates effective in the first quarter of 2007;
- The absence of 2006 litigation expense associated with shareholder lawsuits and Gulf Liquids litigation.

Natural gas prices in the Rocky Mountain areas (Rockies) trended lower throughout 2007 due to strong drilling activities increasing third-party supplies while constrained by limited pipeline capacity. This trend has benefited Midstream as the lower regional gas prices contributed to increased NGL margins in the West region. Exploration & Production utilizes firm transportation contracts, which allow a substantial portion of their Rockies production to be sold at more advantageous market points, and basin-level collars and fixed-price hedges to reduce exposure to this trend.

See additional discussion in Results of Operations.

Recent Events

During third-quarter 2007, we formed Williams Pipeline Partners L.P. (WMZ) to own and operate natural gas transportation and storage assets. In January 2008, WMZ completed its initial public offering of 16.25 million common units at a price of $20.00 per unit. In February 2008, the underwriters also exercised their right to purchase an additional 1.65 million common units at the same price. A subsidiary of ours serves as the general partner of WMZ. The initial asset of the partnership is a 35 percent interest in Northwest Pipeline GP, formerly Northwest Pipeline Corporation. Upon completion of the transaction, we hold approximately 47.7 percent of the interests in WMZ, including the interests of the general partner.

In December 2007, Williams Partners L.P. acquired certain of our membership interests in Wamsutter LLC, the limited liability company that owns the Wamsutter system, from us for $750 million. Williams Partners L.P. completed the transaction after successfully closing a public equity offering of 9.25 million common units that yielded net proceeds of approximately $335 million. The partnership financed the remainder of the purchase price primarily through utilizing $250 million of term loan borrowings and issuing approximately $157 million of common units to us. Since Williams Partners L.P. is consolidated within our consolidated financial statements, the debt and equity issued by Williams Partners L.P. is reported as a component of our consolidated debt balance and minority interest balance, respectively. (See Note 1 of Notes to Consolidated Financial Statements.)

In December 2007, we repurchased $213 million of 7.125 percent notes due September 2011 and $22 million of 8.125 percent notes due March 2012. In conjunction with these early retirements, we paid premiums of approximately $19 million. These premiums, as well as related fees and expenses are recorded as *early debt retirement costs* in the Consolidated Statement of Income.

On November 9, 2007, we closed on the sale of substantially all of our power business to Bear Energy, LP, a unit of The Bear Stearns Companies, Inc., for $496 million, subject to post-closing adjustments. The assets sold included tolling contracts, full requirements contracts, tolling resales, heat rate options, related hedges and other related assets including certain property and software. This sale reduces the risk and complexity of our overall business model.

In November 2007, our credit ratings were raised to investment grade based on improvements in our credit outlook. As we continue to invest and grow our natural gas businesses, our improved credit rating is expected to provide greater access to capital and more favorable loan terms. See additional discussion of credit ratings in *Management's Discussion and Analysis of Financial Condition*.

On November 28, 2007, Transco filed a formal stipulation and agreement with the FERC resolving all substantive issues in Transco's pending 2006 rate case. Final resolution of the rate case is subject to approval by the FERC.

In July 2007, our Board of Directors authorized the repurchase of up to $1 billion of our common stock. We intend to purchase shares of our stock from time to time in open-market transactions or through privately negotiated

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or structured transactions at our discretion, subject to market conditions and other factors. This stock-repurchase program does not have an expiration date. During 2007, we repurchased approximately 16 million shares for $526 million at an average cost of $33.08 per share. We are funding this program with cash on hand.

In April 2007, our Board of Directors approved a regular quarterly dividend of 10 cents per share, which reflected an increase of 11 percent compared to the 9 cents per share that we paid in each of the four prior quarters and marked the fourth increase in our dividend since late 2004.

On March 30, 2007, the FERC approved the stipulation and settlement agreement with respect to the rate case for Northwest Pipeline. The settlement establishes an increase in general system firm transportation rates on Northwest Pipeline's system from $0.30760 to $0.40984 per Dth (dekatherm), effective January 1, 2007.

Outlook for 2008

Our plan for 2008 is focused on continued disciplined growth. Objectives of this plan include:

- Continue to improve both EVA® and segment profit.
- Invest in our businesses in a way that improves EVA®, meets customer needs, and enhances our competitive position.
- Continue to increase natural gas production and reserves.
- Increase the scale of our gathering and processing business in key growth basins.

Potential risks and/or obstacles that could prevent us from achieving these objectives include:

- Volatility of commodity prices;
- Lower than expected levels of cash flow from operations;
- Decreased drilling success at Exploration & Production;
- Decreased drilling success by third parties served by Midstream and Gas Pipeline;
- Exposure associated with our efforts to resolve regulatory and litigation issues (see Note 15 of Notes to Consolidated Financial Statements);
- General economic and industry downturn.

We continue to address these risks through utilization of commodity hedging strategies, focused efforts to resolve regulatory issues and litigation claims, disciplined investment strategies, and maintaining our desired level of at least $1 billion in liquidity from cash and cash equivalents and unused revolving credit facilities.

New Accounting Standards and Emerging Issues

Accounting standards that have been issued and are not yet effective may have an effect on our Consolidated Financial Statements in the future. These include:

- SFAS No. 141(R) "Business Combinations" (SFAS No. 141(R)). SFAS No. 141(R) is effective for business combinations with an acquisition date in fiscal years beginning after December 15, 2008.
- SFAS No. 160 "Noncontrolling Interests in Consolidated Financial Statements — an amendment of Accounting Research Bulletin No. 51" (SFAS No. 160). SFAS No. 160 is effective for fiscal years beginning after December 15, 2008.

See *Recent Accounting Standards* in Note 1 of Notes to Consolidated Financial Statements for further information on these and other recently issued accounting standards.

Critical Accounting Estimates

The preparation of financial statements, in conformity with generally accepted accounting principles, requires management to make estimates and assumptions that affect the reported amounts therein. We have discussed the following accounting estimates and assumptions as well as related disclosures with our Audit Committee. We believe that the nature of these estimates and assumptions is material due to the subjectivity and judgment necessary, or the susceptibility of such matters to change, and the impact of these on our financial condition or results of operations.

Revenue Recognition — Derivative Instruments and Hedging Activities

We hold a portfolio of energy trading and nontrading contracts. We review these contracts to determine whether they are nonderivatives or derivatives. If they are derivatives, we further assess whether the contracts qualify for either cash flow hedge accounting or the normal purchases and normal sales exception.

The determination of whether a derivative contract qualifies as a cash flow hedge includes an analysis of historical market price information to assess whether the derivative is expected to be highly effective in achieving offsetting cash flows attributed to the hedged risk. We also assess whether the hedged forecasted transaction is probable of occurring. This assessment requires us to exercise judgment and consider a wide variety of factors in addition to our intent, including internal and external forecasts, historical experience, changing market and business conditions, our financial and operational ability to carry out the forecasted transaction, the length of time until the forecasted transaction is projected to occur, and the quantity of the forecasted transaction. In addition, we compare actual cash flows to those that were expected from the underlying risk. If a hedged forecasted transaction is not probable of occurring, or if the derivative contract is not expected to be highly effective, the derivative does not qualify for hedge accounting.

For derivatives that are designated as cash flow hedges, we do not reflect the effective portion of changes in their fair value in earnings until the associated hedged item affects earnings. For those that have not been designated as hedges or do not qualify for hedge accounting, we recognize the net change in their fair value in income currently (marked to market).

For derivatives that are designated as cash flow hedges, we prospectively discontinue hedge accounting and recognize future changes in fair value directly in earnings if we no longer expect the hedge to be highly effective, or if we believe that the hedged forecasted transaction is no longer probable of occurring. If the forecasted transaction becomes probable of not occurring, we reclass amounts previously recorded in other comprehensive income into earnings in addition to prospectively discontinuing hedge accounting. If the effectiveness of the derivative improves and is again expected to be highly effective in offsetting cash flows attributed to the hedged risk, or if the forecasted transaction again becomes probable, we may prospectively re-designate the derivative as a hedge of the underlying risk.

Derivatives for which the normal purchases and normal sales exception has been elected are accounted for on an accrual basis. In determining whether a derivative is eligible for this exception, we assess whether the contract provides for the purchase or sale of a commodity that will be physically delivered in quantities expected to be used or sold over a reasonable period in the normal course of business. In making this assessment, we consider numerous factors, including the quantities provided under the contract in relation to our business needs, delivery locations per the contract in relation to our operating locations, duration of time between entering the contract and delivery, past trends and expected future demand, and our past practices and customs with regard to such contracts. Additionally, we assess whether it is probable that the contract will result in physical delivery of the commodity and not net financial settlement.

The fair value of derivative contracts is determined based on the nature of the transaction and the market in which transactions are executed. We also incorporate assumptions and judgments about counterparty performance and credit considerations in our determination of their fair value. Contracts are executed in the following environments:

- Organized commodity exchange or over-the-counter markets with quoted prices;
- Organized commodity exchange or over-the-counter markets with quoted market prices but limited price transparency, requiring increased judgment to determine fair value;
- Markets without quoted market prices.

The number of transactions executed without quoted market prices is limited. We estimate the fair value of these contracts by using readily available price quotes in similar markets and other market analyses. The fair value of all derivative contracts is continually subject to change as the underlying commodity market changes and our assumptions and judgments change.

Additional discussion of the accounting for energy contracts at fair value is included in Energy Trading Activities within Item 7 and Note 1 of Notes to Consolidated Financial Statements.

Oil- and Gas-Producing Activities

We use the successful efforts method of accounting for our oil- and gas-producing activities. Estimated natural gas and oil reserves and forward market prices for oil and gas are a significant part of our financial calculations. Following are examples of how these estimates affect financial results:

- An increase (decrease) in estimated proved oil and gas reserves can reduce (increase) our unit-of-production depreciation, depletion and amortization rates.
- Changes in oil and gas reserves and forward market prices both impact projected future cash flows from our oil and gas properties. This, in turn, can impact our periodic impairment analyses, including that for goodwill.

The process of estimating natural gas and oil reserves is very complex, requiring significant judgment in the evaluation of all available geological, geophysical, engineering, and economic data. After being estimated internally, 99 percent of our reserve estimates are either audited or prepared by independent experts. (See Part I Item 1 for further discussion.) The data may change substantially over time as a result of numerous factors, including additional development activity, evolving production history, and a continual reassessment of the viability of production under changing economic conditions. As a result, material revisions to existing reserve estimates could occur from time to time. A revision of our reserve estimates within reasonably likely parameters is not expected to result in an impairment of our oil and gas properties or goodwill. However, reserve estimate revisions would impact our depreciation and depletion expense prospectively. For example, a change of approximately 10 percent in oil and gas reserves for each basin would change our annual *depreciation, depletion and amortization* expense between approximately $33 million and $41 million. The actual impact would depend on the specific basins impacted and whether the change resulted from proved developed, proved undeveloped or a combination of these reserve categories.

Forward market prices, which are utilized in our impairment analyses, include estimates of prices for periods that extend beyond those with quoted market prices. This forward market price information is consistent with that generally used in evaluating our drilling decisions and acquisition plans. These market prices for future periods impact the production economics underlying oil and gas reserve estimates. The prices of natural gas and oil are volatile and change from period to period, thus impacting our estimates. An unfavorable change in the forward price curve within reasonably likely parameters is not expected to result in an impairment of our oil and gas properties or goodwill.

Contingent Liabilities

We record liabilities for estimated loss contingencies, including environmental matters, when we assess that a loss is probable and the amount of the loss can be reasonably estimated. Revisions to contingent liabilities are generally reflected in income in the period in which new or different facts or information become known or circumstances change that affect the previous assumptions with respect to the likelihood or amount of loss. Liabilities for contingent losses are based upon our assumptions and estimates and upon advice of legal counsel, engineers, or other third parties regarding the probable outcomes of the matter. As new developments occur or more information becomes available, our assumptions and estimates of these liabilities may change. Changes in our assumptions and estimates or outcomes different from our current assumptions and estimates could materially affect future results of operations for any particular quarterly or annual period. See Note 15 of Notes to Consolidated Financial Statements.

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Valuation of Deferred Tax Assets and Tax Contingencies

We have deferred tax assets resulting from certain investments and businesses that have a tax basis in excess of the book basis and from tax carry-forwards generated in the current and prior years. We must evaluate whether we will ultimately realize these tax benefits and establish a valuation allowance for those that may not be realizable. This evaluation considers tax planning strategies, including assumptions about the availability and character of future taxable income. At December 31, 2007, we have $717 million of deferred tax assets for which a $57 million valuation allowance has been established. When assessing the need for a valuation allowance, we considered forecasts of future company performance, the estimated impact of potential asset dispositions and our ability and intent to execute tax planning strategies to utilize tax carryovers. We do not expect to be able to utilize $57 million of foreign deferred tax assets primarily related to carryovers. The ultimate amount of deferred tax assets realized could be materially different from those recorded, as influenced by potential changes in jurisdictional income tax laws and the circumstances surrounding the actual realization of related tax assets.

We regularly face challenges from domestic and foreign tax authorities regarding the amount of taxes due. These challenges include questions regarding the timing and amount of deductions and the allocation of income among various tax jurisdictions. Beginning January 1, 2007, we evaluate the liability associated with our various filing positions by applying the two step process of recognition and measurement as required by Financial Accounting Standards Board (FASB) Interpretation No. 48, "Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109" (FIN 48). The ultimate disposition of these contingencies could have a significant impact on net cash flows. To the extent we were to prevail in matters for which accruals have been established or were required to pay amounts in excess of our accrued liability, our effective tax rate in a given financial statement period may be materially impacted.

See Note 5 of Notes to Consolidated Financial Statements for additional information regarding FIN 48 and tax carryovers.

Pension and Postretirement Obligations

We have employee benefit plans that include pension and other postretirement benefits. Net periodic benefit expense and obligations are impacted by various estimates and assumptions. These estimates and assumptions include the expected long-term rates of return on plan assets, discount rates, expected rate of compensation increase, health care cost trend rates, and employee demographics, including retirement age and mortality. These assumptions are reviewed annually and adjustments are made as needed. The assumptions utilized to compute expense and the benefit obligations are shown in Note 7 of Notes to Consolidated Financial Statements. The following table presents the estimated increase (decrease) in net periodic benefit expense and obligations resulting from a one-percentage-point change in the specified assumption.

	Benefit Expense		Benefit Obligation	
	One-Percentage-Point Increase	One-Percentage-Point Decrease	One-Percentage-Point Increase	One-Percentage-Point Decrease
	(Millions)			
Pension benefits:				
Discount rate	$ (6)	$ 11	$ (106)	$ 120
Expected long-term rate of return on plan assets	(11)	11	—	—
Rate of compensation increase	2	(2)	13	(13)
Other postretirement benefits:				
Discount rate	(4)	—	(37)	43
Expected long-term rate of return on plan assets	(2)	2	—	—
Assumed health care cost trend rate	5	(7)	55	(44)

The expected long-term rates of return on plan assets are determined by combining a review of historical returns realized within the portfolio, the investment strategy included in the plans’ Investment Policy Statement, and capital market projections for the asset classifications in which the portfolio is invested as well as the target weightings of each asset classification. These rates are impacted by changes in general market conditions, but because they are long-term in nature, short-term market swings do not significantly impact the rates. Changes to our target asset allocation would also impact these rates. Our expected long-term rate of return on plan assets used for our pension plans is 7.75 percent for 2007. This rate was 7.75 percent in 2006 and 8.5 percent from 2002-2005. Over the past ten years, our actual average return on plan assets for our pension plans has been approximately 7.7 percent.

The discount rates are used to measure the benefit obligations of our pension and other postretirement benefit plans. The objective of the discount rates is to determine the amount, if invested at the December 31 measurement date in a portfolio of high-quality debt securities, that will provide the necessary cash flows when benefit payments are due. Increases in the discount rates decrease the obligation and, generally, decrease the related expense. The discount rates for our pension and other postretirement benefit plans were determined separately based on an approach specific to our plans and their respective expected benefit cash flows as described in Note 7 of Notes to Consolidated Financial Statements. Our discount rate assumptions are impacted by changes in general economic and market conditions that affect interest rates on long-term high-quality debt securities as well as the duration of our plans' liabilities.

The expected rate of compensation increase represents average long-term salary increases. An increase in this rate causes pension obligation and expense to increase.

The assumed health care cost trend rates are based on our actual historical cost rates that are adjusted for expected changes in the health care industry. An increase in this rate causes other postretirement benefit obligation and expense to increase.

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Results of Operations

Consolidated Overview

The following table and discussion is a summary of our consolidated results of operations for the three years ended December 31, 2007. The results of operations by segment are discussed in further detail following this consolidated overview discussion.

	Years Ended December 31,						
	2007	$ Change from 2006(1)	% Change from 2006(1)	2006	$ Change from 2005(1)	% Change from 2005(1)	2005
	(Millions)			(Millions)			(Millions)
Revenues	$ 10,558	+1,182	+13%	$ 9,376	−405	−4%	$ 9,781
Costs and expenses:							
Costs and operating expenses	8,079	−513	−7%	7,566	+319	+4%	7,885
Selling, general and administrative expenses	471	−82	−21%	389	−112	−40%	277
Other (income) expense — net	(18)	+52	NM	34	+23	+40%	57
General corporate expenses	161	−29	−22%	132	+13	+9%	145
Securities litigation settlement and related costs	—	+167	+100%	167	−158	NM	9
Total costs and expenses	8,693			8,288			8,373
Operating income	1,865			1,088			1,408
Interest accrued — net	(653)	—	—	(653)	+7	+1%	(660)
Investing income	257	+89	+53%	168	+143	NM	25
Early debt retirement costs	(19)	+12	+39%	(31)	−31	NM	—
Minority interest in income of consolidated subsidiaries	(90)	−50	−125%	(40)	−14	−54%	(26)
Other income — net	11	−15	−58%	26	−1	−4%	27
Income from continuing operations before income taxes and cumulative effect of change in accounting principle	1,371			558			774
Provision for income taxes	524	−313	−148%	211	+90	+30%	301
Income from continuing operations	847			347			473
Income (loss) from discontinued operations	143	+181	NM	(38)	+119	+76%	(157)
Income before cumulative effect of change in accounting principle	990			309			316
Cumulative effect of change in accounting principle	—	—	—	—	+2	+100%	(2)
Net income	$ 990			$ 309			$ 314

(1) + = Favorable change to *net income*;− = Unfavorable change to *net income*; NM = A percentage calculation is not meaningful due to change in signs, a zero-value denominator or a percentage change greater than 200.

2007 vs. 2006

The increase in *revenues* is due primarily to higher Midstream revenues associated with increased natural gas liquid (NGL) and olefins marketing revenues and increased production of olefins and NGLs. Exploration & Production experienced higher revenues also due to increases in production volumes and net realized average prices. Additionally, Gas Pipeline revenues increased primarily due to increased rates in effect since the first quarter of 2007. These increases are partially offset by a mark-to-market loss recognized at Gas Marketing Services on a legacy derivative natural gas sales contract that we expect to assign to another party in 2008 under an asset transfer agreement that we executed in December 2007.

The increase in *costs and operating expenses* is due primarily to increased NGL and olefins marketing purchases and increased costs associated with our olefins production business at Midstream. Additionally, Exploration & Production experienced higher depreciation, depletion and amortization and lease operating expenses due primarily to higher production volumes.

The increase in *selling, general and administrative expenses (SG&A)* is primarily due to increased staffing in support of increased drilling and operational activity at Exploration & Production, the absence of a $25 million gain in 2006 related to the sale of certain receivables at Gas Marketing Services, and a $9 million charge related to certain international receivables at Midstream.

Other (income) expense — net within *operating income* in 2007 includes:

- Income of $18 million associated with payments received for a terminated firm transportation agreement on Northwest Pipeline's Grays Harbor lateral;
- Income of $17 million associated with a change in estimate related to a regulatory liability at Northwest Pipeline;
- Income of $12 million related to a favorable litigation outcome at Midstream;
- Income of $8 million due to the reversal of a planned major maintenance accrual at Midstream;
- Expense of $20 million related to an accrual for litigation contingencies at Gas Marketing Services;
- Expense of $10 million related to an impairment of the Carbonate Trend pipeline at Midstream.

Other (income) expense — net within *operating income* in 2006 includes:

- A $73 million accrual for a Gulf Liquids litigation contingency;
- Income of $9 million due to a settlement of an international contract dispute at Midstream.

The increase in *general corporate expenses* is attributable to various factors, including higher employee-related costs, increased levels of charitable contributions and information technology expenses. The higher employee-related costs are primarily the result of higher stock compensation expense. (See Note 1 of Notes to Consolidated Financial Statements.)

The *securities litigation settlement and related costs* is primarily the result of our 2006 settlement related to class-action securities litigation filed on behalf of purchasers of our securities between July 24, 2000 and July 22, 2002. (See Note 15 of Notes to Consolidated Financial Statements.)

The increase in *operating income* reflects record high NGL margins at Midstream, continued strong natural gas production growth at Exploration & Production, the positive effect of new rates at Gas Pipeline, and the absence of 2006 litigation expenses associated with shareholder lawsuits and Gulf Liquids litigation.

Interest accrued — net includes a decrease of $19 million in interest expense associated with our Gulf Liquids litigation contingency, offset by changes in our debt portfolio, most significantly the issuance of new debt in December 2006 by Williams Partners L.P.

The increase in *investing income* is due to:

- An approximate $27 million increase in interest income primarily associated with larger cash and cash equivalent balances combined with slightly higher rates of return in 2007 compared to 2006;
- Increased equity earnings of $38 million due largely to increased earnings of our Gulfstream Natural Gas System, L.L.C. (Gulfstream), Discovery Producer Services LLC (Discovery) and Aux Sable Liquid Products, L.P. (Aux Sable) investments;
- The absence of a $16 million impairment in 2006 of a Venezuelan cost-based investment at Exploration & Production;
- Approximately $14 million of gains from sales of cost-based investments in 2007.

These increases are partially offset by the absence of an approximately $7 million gain on the sale of an international investment in 2006.

Early debt retirement costs in 2007 includes $19 million of premiums and fees related to the December 2007 repurchase of senior unsecured notes. (See Note 11 of Notes to Consolidated Financial Statements.) *Early debt retirement costs* in 2006 includes $27 million in premiums and fees related to the January 2006 debt conversion and $4 million of accelerated amortization of debt expenses related to the retirement of the debt secured by assets of Williams Production RMT Company.

Minority interest in income of consolidated subsidiaries increased primarily due to the growth in the minority interest holdings of Williams Partners L.P.

Provision for income taxes was significantly higher in 2007 due primarily to higher pre-tax earnings. The effective income tax rate for 2007 is slightly higher than the federal statutory rate primarily due to the effect of taxes on foreign operations and an accrual for income tax contingencies, partially offset by the utilization of charitable contribution carryovers not previously benefited. The effective income tax rate for 2006 is slightly higher than the federal statutory rate primarily due to state income taxes, the effect of taxes on foreign operations, nondeductible convertible debenture expenses and an accrual for income tax contingencies, partially offset by the favorable resolution of federal income tax litigation and the utilization of charitable contribution carryovers not previously benefited. The 2006 effective income tax rate has been increased by an adjustment to increase overall deferred income tax liabilities. (See Note 5 of Notes to Consolidated Financial Statements.)

Income (loss) from discontinued operations in 2007 primarily includes the operating results of substantially all of our power business and the sale of that business, which was completed in November 2007. (See Note 2 of Notes to Consolidated Financial Statements.) These results include the following pre-tax items:

- A $429 million gain associated with the reclassification of deferred net hedge gains from *accumulated other comprehensive income,* partially offset by unrealized mark-to-market losses of approximately $23 million;
- A $111 million impairment charge related to the carrying value of certain derivative contracts for which we had previously elected the normal purchases and normal sales exception under SFAS 133 and, accordingly, were no longer recording at fair value;
- A $37 million loss on the sale of substantially all of our power business;
- A $14 million impairment charge for our Hazelton power generation facility.

Income (loss) from discontinued operations in 2006 includes:

- A $14 million net-of-tax loss related to our discontinued power business (see Note 2 of Notes to Consolidated Financial Statements);
- A $12 million net-of-tax litigation settlement related to our former chemical fertilizer business;
- A $4 million net-of-tax charge associated with the settlement of a loss contingency related to a former exploration business;
- A $9 million net-of-tax charge associated with an oil purchase contract related to our former Alaska refinery.

2006 vs. 2005

The decrease in *revenues* is primarily due to lower natural gas realized revenues at Gas Marketing Services associated with lower natural gas sales prices. Additionally, the effect of a change in forward prices on legacy natural gas derivative contracts not designated as cash flow hedges had an unfavorable impact on revenues. Partially offsetting these decreases are increased crude, olefin and NGL marketing revenues, higher NGL production revenue at Midstream and increased production revenue at Exploration & Production.

The decrease in *costs and operating expenses* is largely due to reduced natural gas purchase prices at Gas Marketing Services. Partially offsetting these decreases are increased crude, olefin and NGL marketing purchases and operating expenses at Midstream and increased depreciation, depletion and amortization and lease operating expense at Exploration & Production.

The increase in *SG&A expenses* is primarily due to increased personnel costs, insurance expense, higher information systems support costs and the absence of a $17 million reduction of pension expense at Gas Pipeline in 2005. Additionally, Exploration & Production experienced higher costs due to increased staffing in support of increased drilling and operational activity.

Other (income) expense — net within *operating income* in 2005 includes:

- An $82 million accrual for litigation contingencies at Gas Marketing Services, associated primarily with agreements reached to substantially resolve exposure related to certain natural gas price and volume reporting issues;

- Gains totaling $30 million on the sale of certain natural gas properties at Exploration & Production;

- A gain of $9 million on a sale of land in our Other segment.

General corporate expenses decreased primarily due to the absence of $14 million of insurance settlement charges in 2005 associated with certain insurance coverage allocation issues.

The decrease in *operating income* primarily reflects the negative effect of a change in forward prices on natural gas derivative contracts at Gas Marketing Services, higher operating and administrative costs at Gas Pipeline and 2006 litigation expenses associated with shareholder lawsuits and Gulf Liquids litigation. These decreases are partially offset by higher margins at Midstream and the absence a 2005 accrual for estimated litigation contingencies associated primarily with agreements reached to substantially resolve exposure related to natural gas price and volume reporting issues.

Interest accrued — net in 2006 includes $22 million in interest expense associated with our Gulf Liquids litigation contingency.

The increase in *investing income* is due to:

- The absence of an $87 million impairment in 2005 on our investment in Longhorn Partners Pipeline, L.P. (Longhorn);

- The absence of a $23 million impairment in 2005 of our Aux Sable equity investment;

- An approximate $30 million increase in interest income primarily associated with increased earnings on cash and cash equivalent balances associated with higher rates of return;

- Increased equity earnings of $33 million due largely to the absence of equity losses in 2006 on Longhorn and increased earnings of our Discovery and Aux Sable investments.

These increases are partially offset by:

- A $16 million impairment of a Venezuelan cost-based investment at Exploration & Production in 2006;

- The absence of a $9 million gain on sale of our remaining Mid-America Pipeline (MAPL) and Seminole Pipeline (Seminole) investments at Midstream in 2005.

The increase in *minority interest in income of consolidated subsidiaries* is primarily due to the growth of Williams Partners L.P.

Provision for income taxes was significantly lower in 2006 due primarily to lower pre-tax earnings. The effective income tax rate for 2006 is slightly higher than the federal statutory rate primarily due to state income taxes, the effect of taxes on foreign operations, nondeductible convertible debenture expenses and an accrual for income tax contingencies, partially offset by the favorable resolution of federal income tax litigation and the utilization of charitable contribution carryovers not previously benefited. The 2006 effective income tax rate has been increased by an adjustment to increase overall deferred income tax liabilities. The effective income tax rate for 2005 is higher than the federal statutory rate due primarily to state income taxes, nondeductible expenses and the inability to utilize charitable contribution carryovers. The 2005 effective income tax rate was reduced by an adjustment to reduce overall deferred income tax liabilities and favorable settlements on federal and state income tax matters. (See Note 5 of Notes to Consolidated Financial Statements.)

Income (loss) from discontinued operations in 2005 includes a $155 million net-of-tax loss related to our discontinued power business. (See Note 2 of Notes to Consolidated Financial Statements.)

Cumulative effect of change in accounting principle in 2005 is due to the implementation of FIN 47.

Results of Operations — Segments

We are currently organized into the following segments: Exploration & Production, Gas Pipeline, Midstream, Gas Marketing Services, and Other. Other primarily consists of corporate operations. Our management currently evaluates performance based on segment profit (loss) from operations. (See Note 17 of Notes to Consolidated Financial Statements.)

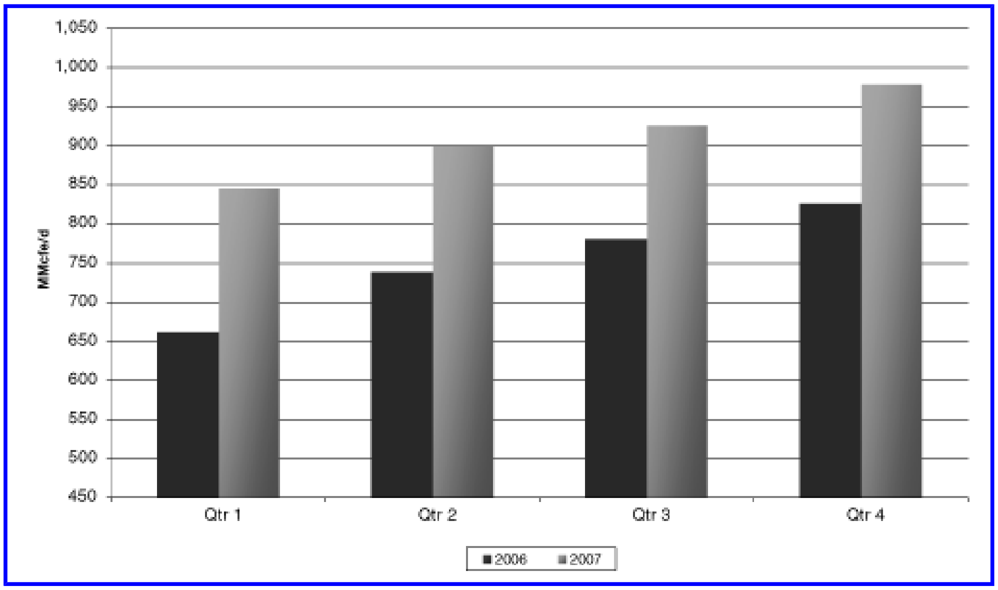
Exploration & Production

Overview of 2007

In 2007, we continued our strategy of a rapid execution of our development drilling program in our growth basins. Accordingly, we:

- Increased average daily domestic production levels by approximately 21 percent compared to last year. The average daily domestic production was approximately 913 million cubic feet of gas equivalent (MMcfe) in 2007 compared to 752 MMcfe in 2006. The increased production is primarily due to increased development within the Piceance, Powder River, and Fort Worth basins.

2007 vs 2006 Domestic Production



Average daily domestic production grew 21 percent or 161 MMcfe per day

- Benefited from increased domestic net realized average prices, which increased by approximately 15 percent compared to last year. The domestic net realized average price was $5.08 per thousand cubic feet of gas equivalent (Mcfe) in 2007 compared to $4.40 per Mcfe in 2006. Net realized average prices include market prices, net of fuel and shrink and hedge positions, less gathering and transportation expenses.
- Utilized firm transportation contracts which allowed a substantial portion of our Rockies production to be sold at more advantageous market points outside of the Rocky Mountain markets. Basin-level collars and fixed-price hedges also reduced our exposure to natural gas prices in the Rockies.
- Continued our aggressive development drilling program, drilling 1,590 gross wells in 2007 with a success rate of over 99 percent. This contributed to total net additions of 776 billion cubic feet equivalent (Bcfe) in net reserves — a replacement rate for our domestic production of 232 percent in 2007 compared to 216 percent in 2006. Capital expenditures for domestic drilling, development, and acquisition activity in 2007 were approximately $1.7 billion compared to approximately $1.4 billion in 2006.

The benefits of higher production volumes and higher net realized average prices were partially offset by increased operating costs. The increase in operating costs was primarily due to increased production volumes and higher well service and industry costs. In addition, higher production volumes increased depletion, depreciation and amortization expense.

Significant events

In February 2007, we entered into a five-year unsecured credit agreement with certain banks in order to reduce margin requirements related to our hedging activities as well as lower transaction fees. Margin requirements, if any, under this new facility are dependent on the level of hedging and on natural gas reserves value. (See Note 11 of Notes to Consolidated Financial Statements.) We may also execute hedges with the Gas Marketing Services segment, which, in turn, executes offsetting derivative contracts with unrelated third parties. In this situation, Gas Marketing Services, generally, bears the counterparty performance risks associated with unrelated third parties. Hedging decisions primarily are made considering our overall commodity risk exposure and are not executed independently by Exploration & Production.

In May and July 2007, we increased our position in the Fort Worth basin by acquiring producing properties and leasehold acreage for approximately $41 million. These acquisitions are consistent with our growth strategy of leveraging our horizontal drilling expertise by acquiring and developing low-risk properties in the Barnett Shale formation. In July 2007, we increased our position in the Piceance basin by acquiring additional undeveloped leasehold acreage for approximately $36 million.

Outlook for 2008

Our expectations and objectives for 2008 include:

- Maintaining our development drilling program in our key basins of Piceance, Powder River, San Juan, Arkoma, and Fort Worth through our planned capital expenditures projected between $1.45 billion and $1.65 billion.
- Continuing to grow our average daily domestic production level with a goal of approximately 10 to 15 percent annual growth.

Natural gas prices in the Rocky Mountain areas trended lower throughout 2007 due to strong drilling activities increasing supplies while constrained by limited pipeline capacity. However, we will continue to utilize firm transportation contracts which allow a substantial portion of our Rockies production to be sold at more advantageous market points. Our continued use of basin-level collars and fixed-price hedges should also reduce our exposure to this trend. The construction of a new third-party pipeline that began transporting gas from the Rocky Mountain areas in the beginning of 2008 should lessen pipeline transportation capacity constraints and provided an additional alternative market for the sale of production.

Approximately 70 MMcf of our forecasted 2008 daily domestic production is hedged by NYMEX and basis fixed-price contracts at prices that average $3.97 per Mcf at a basin level. In addition, we have the following collar agreements for our forecasted 2008 daily domestic production, shown at basin-level weighted-average prices and weighted-average volumes:

	Volume (MMcf/d)	Floor Price ($/Mcf)	Ceiling Price ($/Mcf)
2008 collar agreements:			
Northwest Pipeline/Rockies	170	$ 6.16	$ 9.14
El Paso/San Juan	202	$ 6.35	$ 8.96
Mid-Continent (PEPL)	25	$ 6.91	$ 9.13

Risks to achieving our expectations include unfavorable natural gas market price movements which are impacted by numerous factors including weather conditions and domestic natural gas production and consumption. Also, achievement of expectations can be affected by costs of services associated with drilling.

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In January 2008, we sold a contractual right to a production payment on certain future international hydrocarbon production for approximately $148 million. We have received $118 million in cash and $29 million has been placed in escrow subject to certain post-closing conditions and adjustments. We will recognize a pre-tax gain of approximately $118 million in the first quarter of 2008 related to the initial cash received. As a result of the contract termination, we have no further interests associated with the crude oil concession, which is located in Peru. We had obtained these interests through our acquisition of Barrett Resources Corporation in 2001.

Year-Over-Year Operating Results

	Years Ended December 31,		
	2007	2006	2005
		(Millions)	
Segment revenues	$2,093	$1,488	$1,269
Segment profit	$ 756	$ 552	$ 587

2007 vs. 2006

Total *segment revenues* increased $605 million, or 41 percent, primarily due to the following:

- $487 million, or 39 percent, increase in domestic production revenues reflecting $264 million associated with a 21 percent increase in production volumes sold and $223 million associated with a 15 percent increase in net realized average prices. The increase in production volumes reflects an increase in the number of producing wells primarily from the Piceance and Powder River basins. The impact of hedge positions on increased net realized average prices includes both the expiration of a portion of fixed-price hedges that are lower than the current market prices and higher than current market prices related to basin-specific collars entered into during the period. Production revenues in 2007 include approximately $53 million related to natural gas liquids. In 2006, approximately $29 million of similar revenues were classified within other revenues;
- $139 million increase in revenues for gas management activities related to gas sold on behalf of certain outside parties which is offset by a similar increase in *segment costs and expenses*;

These increases were partially offset by a $30 million decrease relating to hedge ineffectiveness. In 2006, there were $14 million in net unrealized gains from hedge ineffectiveness as compared to $16 million in net unrealized losses in 2007.

To manage the commodity price risk and volatility of owning producing gas properties, we enter into derivative forward sales contracts that fix the sales price relating to a portion of our future production. Approximately 19 percent of domestic production in 2007 was hedged by NYMEX and basis fixed-price contracts at a weighted-average price of $3.90 per Mcf at a basin level compared to 40 percent hedged at a weighted-average price of $3.82 per Mcf for 2006. Also, approximately 30 percent and 15 percent of 2007 and 2006 domestic production was

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hedged in the following collar agreements shown at basin-level weighted-average prices and weighted-average volumes:

	Volume (MMcf/d)	Floor Price ($/Mcf)	Ceiling Price ($/Mcf)
2007 collar agreements:			
NYMEX	15	$ 6.50	$ 8.25
Northwest Pipeline/Rockies	50	$ 5.65	$ 7.45
El Paso/San Juan	130	$ 5.98	$ 9.63
Mid-Continent (PEPL)	76	$ 6.82	$ 10.77
2006 collar agreements:			
NYMEX	49	$ 6.50	$ 8.25
NYMEX	15	$ 7.00	$ 9.00
Northwest Pipeline/Rockies	50	$ 6.05	$ 7.90

Total *segment costs and expenses* increased $404 million, primarily due to the following:

- $173 million higher depreciation, depletion and amortization expense primarily due to higher production volumes and increased capitalized drilling costs;
- $139 million increase in expenses for gas management activities related to gas purchased on behalf of certain outside parties which is offset by a similar increase in *segment revenues*;
- $46 million higher lease operating expenses from the increased number of producing wells primarily within the Piceance, Powder River, and Fort Worth basins in combination with higher well service expenses, facility expenses, equipment rentals, maintenance and repair services, and salt water disposal expenses;
- $36 million higher *SG&A expenses* primarily due to increased staffing in support of increased drilling and operational activity, including higher compensation. In addition, we incurred higher insurance and information technology support costs related to the increased activity. First quarter 2007 also includes approximately $5 million of expenses associated with a correction of costs incorrectly capitalized in prior periods.

The $204 million increase in s*egment profit* is primarily due to the 21 percent increase in domestic production volumes sold as well as the 15 percent increase in net realized average prices, partially offset by the increase in *segment costs and expenses.*

2006 vs. 2005

Total *segment revenues* increased $219 million, or 17 percent, primarily due to the following:

- $165 million, or 15 percent, increase in domestic production revenues reflecting $245 million primarily associated with a 23 percent increase in natural gas production volumes sold, offset by a decrease of $80 million associated with a 6 percent decrease in net realized average prices. The increase in production volumes is primarily from the Piceance and Powder River basins and the decrease in prices reflects the downward trending of market prices in the latter part of 2006.
- $10 million increase in production revenues from our international operations primarily due to increases in net realized average prices for crude oil production volumes sold.
- $14 million of net unrealized gains in 2006 from hedge ineffectiveness and forward mark-to-market gains on certain basis swaps not designated as hedges as compared to $10 million in net unrealized losses attributable to hedge ineffectiveness from NYMEX collars in 2005.

In 2005, approximately 47 percent of domestic production was hedged by NYMEX and basis fixed-price contracts at a weighted-average price of $3.99 per Mcf. Approximately 10 percent of domestic production was hedged by a NYMEX collar agreement for approximately 50 MMcf per day at a floor price of $7.50 per Mcf and a ceiling price of $10.49 per Mcf in the first quarter and at a floor price of $6.75 per Mcf and a ceiling price of $8.50 per Mcf in the second, third, and fourth quarters, and a Northwest Pipeline/Rockies collar agreement for approximately 50 MMcf per day in the fourth quarter at a floor price of $6.10 per Mcf and a ceiling price of $7.70 per Mcf.

Total *segment costs and expenses* increased $257 million, primarily due to the following:

- $107 million higher depreciation, depletion and amortization expense primarily due to higher production volumes and increased capitalized drilling costs;
- $54 million higher lease operating expense primarily due to the increased number of producing wells and higher well service and industry costs due to increased demand and approximately $6 million for out-of-period expenses related to 2005;
- $33 million higher selling, general and administrative expenses primarily due to higher compensation for additional staffing in support of increased drilling and operational activity. In addition, we incurred higher legal, insurance, and information technology support costs related to the increased activity;
- $19 million higher operating taxes primarily due to higher production volumes sold and increased tax rates;
- The absence in 2006 of $30 million of gains on the sales of properties in 2005.

The $35 million decrease in *segment profit* is primarily due to lower net realized average prices and higher *segment costs and expenses* as discussed previously, and the absence in 2006 of $30 million of gains on the sales of properties in 2005. Partially offsetting these decreases are a 23 percent increase in domestic production volumes sold and increase in income from ineffectiveness and forward mark-to-market gains. *Segment profit* also includes an $8 million increase in our international operations primarily due to higher revenue and equity earnings as a result of increases in net realized average prices for crude oil production volumes sold.

Gas Pipeline

Overview

Our strategy to create value for our shareholders focuses on maximizing the utilization of our pipeline capacity by providing high quality, low cost transportation of natural gas to large and growing markets.

Gas Pipeline's interstate transmission and storage activities are subject to regulation by the FERC and as such, our rates and charges for the transportation of natural gas in interstate commerce, and the extension, expansion or abandonment of jurisdictional facilities and accounting, among other things, are subject to regulation. The rates are established through the FERC's ratemaking process. Changes in commodity prices and volumes transported have little impact on revenues because the majority of cost of service is recovered through firm capacity reservation charges in transportation rates.

Significant events of 2007 include:

Gas Pipeline master limited partnership

During third-quarter 2007, we formed Williams Pipeline Partners L.P. (WMZ) to own and operate natural gas transportation and storage assets. In January 2008, WMZ completed its initial public offering of 16.25 million common units at a price of $20.00 per unit. In February 2008, the underwriters also exercised their right to purchase an additional 1.65 million common units at the same price. A subsidiary of ours serves as the general partner of WMZ. The initial asset of the partnership is a 35 percent interest in Northwest Pipeline GP, formerly Northwest Pipeline Corporation. Upon completion of the transaction, we hold approximately 47.7 percent of the interests in WMZ, including the interests of the general partner.

Status of rate cases

During 2006, Northwest Pipeline and Transco each filed general rate cases with the FERC for increases in rates. The new rates were effective, subject to refund, on January 1, 2007, for Northwest Pipeline and on March 1, 2007, for Transco.

On March 30, 2007, the FERC approved the stipulation and settlement agreement with respect to the rate case for Northwest Pipeline. The settlement establishes an increase in general system firm transportation rates on Northwest Pipeline's system from $0.30760 to $0.40984 per Dth (dekatherm), effective January 1, 2007.

On November 28, 2007, Transco filed a formal stipulation and agreement with the FERC resolving all substantive issues in Transco's pending 2006 rate case. Final resolution of the rate case is subject to approval by the FERC.

Parachute Lateral project

In May 2007, we placed into service a 37.6-mile expansion of 30-inch diameter line in northwest Colorado. The expansion increased capacity by 450 Mdt/d at a cost of approximately $86 million. In December 2007, this asset was purchased by Midstream. In an arrangement approved by the FERC, Midstream will lease the pipeline to Gas Pipeline, who will continue to operate the pipeline until completion of a planned FERC abandonment filing.

Leidy to Long Island expansion project

In December 2007, we placed into service an expansion of certain existing pipeline facilities in the northeast United States. The project increased firm transportation capacity by 100 Mdt/d at an approximate cost of $169 million.

Potomac expansion project

In November 2007, we placed into service 16.5 miles of 42-inch pipeline in the Mid-Atlantic region of the United States. The second phase of the project involving installation of certain facilities will be completed in the fall of 2008. The project provides 165 Mdt/d of incremental firm capacity at an approximate total cost of $88 million.

Outlook for 2008

Gulfstream

In June 2007, our equity method investee, Gulfstream, received FERC approval to extend its existing pipeline approximately 34 miles within Florida. The extension will fully subscribe the remaining 345 Mdt/d of firm capacity on the existing pipeline. Construction began in January 2008. The estimated cost of this project is approximately $130 million and is expected to be placed into service in July 2008.

In September 2007, Gulfstream received FERC approval to construct 17.5 miles of 20-inch pipeline and to install a new compressor facility. Construction began in December 2007. The pipeline expansion will increase capacity by 155 Mdt/d and is expected to be placed into service in September 2008. The compressor facility is expected to be placed into service in January 2009. The estimated cost of this project is approximately $153 million.

Sentinel expansion project

In December 2007, we filed an application with the FERC to construct an expansion in the northeast United States. The estimated cost of the project is approximately $169 million. The expansion will increase capacity by 142 Mdt/d and is expected to be placed into service in two phases, occurring in November 2008 and November 2009.

Jackson Prairie expansion project

We own a one-third interest in the Jackson Prairie underground storage facility located in Washington, with the remaining interests owned by two of our distribution customers. In February 2007, we received FERC approval to expand the Jackson Prairie facility. The expansion will increase our one-third share of the capacity by 104 Mdt/d and is expected to be placed into service in November 2008.

Year-Over-Year Operating Results

	Years Ended December 31,		
	2007	2006	2005
		(Millions)	
Segment revenues	$1,610	$1,348	$1,413
Segment profit	$ 673	$ 467	$ 586

2007 vs. 2006

Revenues increased $262 million, or 19 percent, due primarily to a $173 million increase in transportation revenue and a $25 million increase in storage revenue resulting primarily from new rates effective in the first quarter of 2007. In addition, revenues increased $59 million due to the sale of excess inventory gas.

Costs and operating expenses increased $86 million, or 11 percent, due primarily to:

- An increase of $59 million associated with the sale of excess inventory gas, which includes a $19 million deferred gain, half of which will be payable to customers, pending FERC approval;
- An increase in depreciation expense of $30 million due to property additions;
- An increase in personnel costs of $10 million due primarily to higher compensation as well as an increase in number of employees;
- The absence of a $3 million credit to expense recorded in 2006 related to corrections of the carrying value of certain liabilities.

Partially offsetting these increases is a decrease of $12 million in contract and outside service costs and a decrease of $7 million in materials and supplies expense.

Other (income) expense — net changed favorably by $15 million due primarily to $18 million of income associated with payments received for a terminated firm transportation agreement on Northwest Pipeline's Grays Harbor lateral. Also included in the favorable change is $17 million of income recorded in the second quarter of 2007 for a change in estimate related to a regulatory liability at Northwest Pipeline, partially offset by $18 million of expense related to higher asset retirement obligations.

Equity earnings increased $14 million due primarily to a $14 million increase in equity earnings from Gulfstream. Gulfstream's higher earnings were primarily due to a decrease in property taxes from a favorable litigation outcome as well as improved operating results.

The $206 million, or 44 percent, increase in *segment profit* is due primarily to $262 million higher revenues, $14 million higher equity earnings and $15 million favorable *other (income) expense — net* as previously discussed. Partially offsetting these increases are higher *costs and operating expenses* as previously discussed.

2006 vs. 2005

Significant 2005 adjustments

Operating results for 2005 included:

- Adjustments of $18 million reflected as a $12 million reduction of *costs and operating expenses* and a $6 million reduction of *SG&A expenses*. These cost reductions were corrections of the carrying value of certain liabilities that were recorded in prior periods. Based on a review by management, these liabilities were no longer required.
- Pension expense reduction of $17 million in the second quarter of 2005 to reflect the cumulative impact of a correction of an error attributable to 2003 and 2004. The error was associated with the actuarial

computation of annual net periodic pension expense and resulted from the identification of errors in certain Transco participant data involving annuity contract information utilized for 2003 and 2004.

- Adjustments of $37 million reflected as increases in *costs and operating expenses* related to $32 million of prior period accounting and valuation corrections for certain inventory items and an accrual of $5 million for contingent refund obligations.

Revenues decreased $65 million, or 5 percent, due primarily to $75 million lower revenues associated with exchange imbalance settlements (offset in *costs and operating expenses*). Partially offsetting this decrease is a $9 million increase in revenue due to an adjustment for the recovery of state income tax rate changes (offset in *provision for income taxes*).

Costs and operating expenses decreased $17 million, or 2 percent, due primarily to:

- A decrease in costs of $75 million associated with exchange imbalance settlements (offset in *revenues*);
- A decrease in costs of $37 million related to the absence of $32 million of 2005 prior period accounting and valuation corrections for certain inventory items and an accrual of $5 million for contingent refund obligations.

Partially offsetting these decreases are:

- An increase in contract and outside service costs of $23 million due primarily to higher pipeline assessment and repair costs;
- An increase in depreciation expense of $15 million due to property additions;
- An increase in operating and maintenance expenses of $15 million;
- An increase in operating taxes of $10 million;
- The absence of $14 million of income in 2005 associated with the resolution of litigation;
- The absence of $12 million of expense reductions during 2005 related to the carrying value of certain liabilities.

SG&A expenses increased $77 million, or 92 percent, due primarily to:

- An increase in personnel costs of $18 million;
- The absence of a 2005 $17 million reduction in pension costs to correct an error in prior periods;
- An increase in information systems support costs of $16 million;
- An increase in property insurance expenses of $14 million;
- The absence of $6 million of cost reductions in 2005 that related to correcting the carrying value of certain liabilities.

The $119 million, or 20 percent, decrease in *segment profit* is due primarily to the absence of significant 2005 adjustments as previously discussed, increases in *costs and operating expenses* and *SG&A expenses* as previously discussed, and the absence of a $5 million construction completion fee recognized in 2005 related to our investment in Gulfstream.

Midstream Gas & Liquids

Overview of 2007

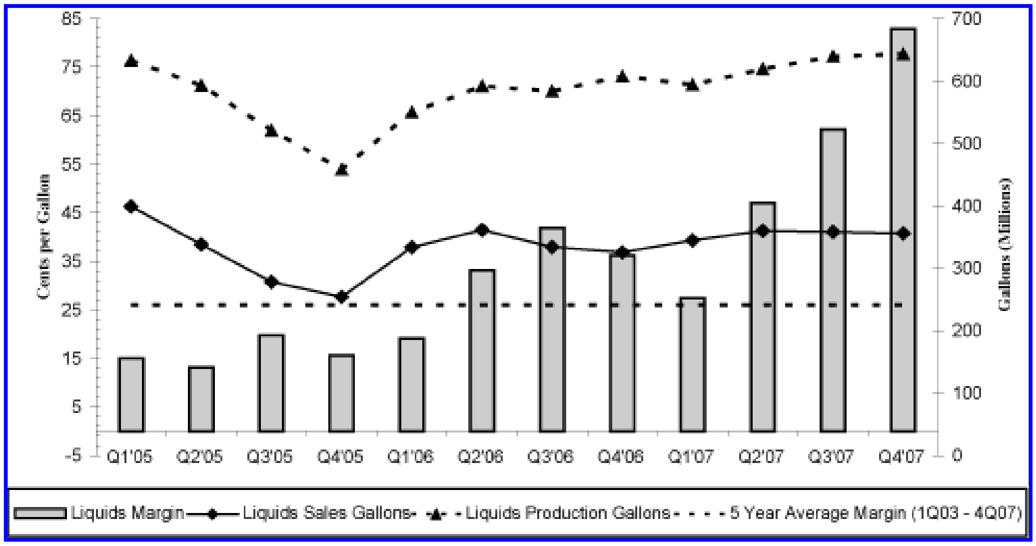
Midstream's ongoing strategy is to safely and reliably operate large-scale midstream infrastructure where our assets can be fully utilized and drive low per-unit costs. Our business is focused on consistently attracting new business by providing highly reliable service to our customers.

Significant events during 2007 include the following:

Continued favorable commodity price margins

The average realized natural gas liquid (NGL) per unit margins at our processing plants during 2007 was a record high 55 cents per gallon. NGL margins exceeded Midstream's rolling five-year average for the last seven quarters. The geographic diversification of Midstream assets contributed significantly to our realized unit margins resulting in margins generally greater than that of the industry benchmarks for gas processed in the Henry Hub area and fractionated and sold at Mont Belvieu. The largest impact was realized at our western United States gas processing plants, which benefited from lower regional market natural gas prices.

Domestic Gathering and Processing Per Unit NGL Margin with Production and Sales Volumes by Quarter (excludes partially owned plants)



Expansion efforts in growth areas

Consistent with our strategy, we continued to expand our midstream operations where we have large-scale assets in growth basins.

During the first quarter of 2007, we completed construction at our existing gas processing complex located near Opal, Wyoming, to add a fifth cryogenic gas processing train capable of processing up to 350 MMcf/d, bringing total Opal capacity to approximately 1,450 MMcf/d. This plant expansion became operational during the first quarter. We also have several expansion projects ongoing in the West region to lower field pressures and increase production volumes for our customers who continue robust drilling activities in the region.

We continue construction of 37-mile extensions of both of our oil and gas pipelines from our Devils Tower spar to the Blind Faith prospect located in Mississippi Canyon. These extensions, estimated to cost approximately $250 million, are expected to be ready for service by the second quarter of 2008.

During 2007, we have continued construction activities on the Perdido Norte project which includes oil and gas lines that would expand the scale of our existing infrastructure in the western deepwater of the Gulf of Mexico. In addition, we completed agreements with certain producers to provide gathering, processing and transportation services over the life of the reserves. We also intend to expand our Markham gas processing facility to adequately serve this new gas production. The scale of the project has increased to include additional pipeline and more efficient processing capacity. The estimated cost is now approximately $560 million, and it is expected to be in service in the third quarter of 2009.

In July 2007, we exercised our right of first refusal to acquire BASF's 5/12th ownership interest in the Geismar olefins facility for approximately $62 million. The acquisition increases our total ownership to 10/12th.

In March 2007, we announced plans to construct and operate the new Willow Creek facility, a 450 MMcf/d natural gas processing plant in western Colorado's Piceance basin, where Exploration & Production has its most significant volume of natural gas production, reserves and development activity. Exploration & Production's existing Piceance basin processing plants are primarily designed to condition the natural gas to meet quality specifications for pipeline transmission, not to maximize the extraction of NGLs. We expect the new Willow Creek facility to recover 25,000 barrels per day of NGLs at startup, which is expected to be in the third quarter of 2009.

In December 2007, we purchased the Parachute Lateral system from Gas Pipeline. The system is a 37.6-mile expansion, originally placed in service by Gas Pipeline in May 2007, and provides capacity of 450 Mdt/d through a 30-inch diameter line, transporting residue gas from the Piceance basin to the Greasewood Hub in northwest Colorado. The Willow Creek facility will straddle the Parachute Lateral pipeline and will process gas flowing through the pipeline. In an arrangement approved by the FERC, Midstream will lease the pipeline to Gas Pipeline, who will continue to operate the pipeline until completion of a planned FERC abandonment filing.

In addition, we have acquired an existing natural gas pipeline from Gas Pipeline, and begun the process of converting it from natural gas to NGL service and constructing additional pipeline to create a pipeline alternative for NGLs currently being transported by truck from Exploration & Production's existing Piceance basin processing plants to a major NGL transportation pipeline system.

We have also agreed to dedicate our equity NGL volumes from Willow Creek, along with our two Wyoming plants, for transport under a long-term shipping agreement with Overland Pass Pipeline Company, LLC. We currently have a 1 percent interest in Overland Pass Pipeline Company, LLC and have the option to increase our ownership to 50 percent and become the operator within two years of the pipeline becoming operational. Start-up is planned for mid-2008. The terms of the shipping agreement represent significant savings compared with agreements we are now utilizing.

Williams Partners L.P.

We currently own approximately 23.6 percent of Williams Partners L.P., including the interests of the general partner, which is wholly owned by us. Considering the control of the general partner in accordance with EITF Issue No. 04-5, Williams Partners L.P. is consolidated within the Midstream segment. (See Note 1 of Notes to Consolidated Financial Statements.) Midstream's segment profit includes 100 percent of Williams Partners L.P.'s segment profit, with the minority interest's share deducted below segment profit. The debt and equity issued by Williams Partners L.P. to third parties is reported as a component of our consolidated debt balance and minority interest balance, respectively.

In June 2007, Williams Partners L.P. completed its acquisition of our 20 percent interest in Discovery Producer Services, LLC (Discovery). Williams Partners L.P. now owns a 60 percent interest in Discovery.

In December 2007, Williams Partners L.P. acquired certain of our membership interests in Wamsutter LLC, the limited liability company that owns the Wamsutter system, from us for $750 million. Williams Partners L.P. completed the transaction after successfully closing a public equity offering of 9.25 million common units that yielded net proceeds of approximately $335 million. The partnership primarily financed the remainder of the purchase price through utilizing $250 million of term loan borrowings and issuing approximately $157 million of common units to us. The $250 million term loan is under Williams Partners L.P.'s new $450 million five-year senior unsecured credit facility that became effective simultaneous with the closing of the Wamsutter transaction. (See Note 11 of Notes to Consolidated Financial Statements.)

Ignacio Gas Processing Plant Fire

On November 28, 2007, there was a fire at the Ignacio gas processing plant. This fire resulted in severe damage to the facility's cooling tower, control room, adjacent warehouse buildings and control systems. The plant was shut down until January 18, 2008. There were no injuries as a result of this incident and the plant now has full cryogenic recovery capability available for operation. The impact of the fire was immaterial to our results of operations.

Outlook for 2008

The following factors could impact our business in 2008 and beyond.

- As evidenced in recent years, natural gas and crude oil markets are highly volatile. NGL margins earned at our gas processing plants in the last seven quarters were above our rolling five-year average, due to global economics maintaining high crude prices which correlate to strong NGL prices in relationship to natural gas prices. Forecasted domestic demand for ethylene and propylene, along with political instability in many of the key oil producing countries, currently support NGL margins continuing to exceed our rolling five-year average. Natural gas prices in the Rocky Mountain areas have trended lower throughout 2007 due to strong drilling activities increasing supplies while third-party production volumes have been constrained by limited pipeline capacity. The construction of a new third-party pipeline that began transporting gas from the Rocky Mountain areas in the beginning of 2008 would indicate increasing natural gas prices, moderating our future NGL margins.
- If the previously mentioned Overland Pass pipeline is not completed as scheduled, our NGL transportation costs will increase in the short-term over 2007 levels. When the pipeline is complete, the terms of our transportation agreement represent significant savings compared to 2007.
- As part of our efforts to manage commodity price risks on an enterprise basis, during December 2007 and January and February 2008, we entered into various financial contracts. Approximately 28 percent of our forecasted domestic NGL sales for 2008 are hedged with collar agreements or fixed-price swap contracts. Approximately 24 percent of our forecasted domestic NGL sales have been hedged with collar agreements at a weighted average sales price range of 9 percent to 22 percent above our average 2007 domestic NGL sales price and approximately 4 percent of our forecasted domestic NGL sales have been hedged with fixed-price swap contracts. The natural gas shrink requirements associated with the sales under the fixed-price swap contracts have also been hedged through Gas Marketing Services with physical gas purchase contracts, thus effectively hedging the margin on the volumes associated with fixed price swap contracts at a level about two times our rolling five-year average and approximating our 2007 average.
- Margins in our olefins business are highly dependent upon continued economic growth within the United States and any significant slow down in the economy would reduce the demand for the petrochemical products we produce in both Canada and the United States. Based on our increased ownership in our Geismar facility, we anticipate results from our olefins business to be above 2007 levels.
- Gathering and processing fee revenues in our West region in 2008 are expected to be at or slightly above levels of previous years due to continued strong drilling activities in our core basins.
- We expect fee revenues in our Gulf Coast region to increase in 2008 as we expand our Devil's Tower infrastructure to serve the Blind Faith and Bass Lite prospects. This increase is expected to be partially offset by lower volumes in other deepwater areas due to natural declines. Fee revenues include gathering, processing, production handling and transportation fees.
- Revenues from deepwater production areas are often subject to risks associated with the interruption and timing of product flows which can be influenced by weather and other third-party operational issues.
- The construction of deepwater pipelines is subject to the risk of pipe collapse from stresses during installation as well as from high hydrostatic pressure that could delay completion and increase costs. Our Perdido Norte project is located in the Gulf Coast region in the deepwater Gulf of Mexico and subject to these risks.

- We will continue to invest in facilities in the growth basins in which we provide services. We expect continued expansion of our gathering and processing systems in our Gulf Coast and West regions to keep pace with increased demand for our services. As we pursue these activities, our operating and general and administrative expenses are expected to increase.
- We expect continued expansion in the deepwater areas of the Gulf of Mexico to contribute to our future segment revenues and segment profit. We expect these additional fee-based revenues to lower our proportionate exposure to commodity price risks.
- The Venezuelan government continues its public criticism of U.S. economic and political policy, has implemented unilateral changes to existing energy related contracts, and has expropriated privately held assets within the energy and telecommunications sector, escalating our concern regarding political risk in Venezuela.
- Our right of way agreement with the Jicarilla Apache Nation (JAN), which covered certain gathering system assets in Rio Arriba County of northern New Mexico, expired on December 31, 2006. We currently operate our gathering assets on the JAN lands pursuant to a special business license granted by the JAN which expires February 29, 2008. We are engaged in discussions with the JAN designed to result in the sale of our gathering assets which are located on or are isolated by the JAN lands. Provided the parties are able to reach an acceptable value on the sale of the subject gathering assets, our expectation is that we will nonetheless maintain partial revenues associated with gathering and processing downstream of the JAN lands and continue to operate the gathering assets on the JAN lands for an undetermined period of time beyond February 29, 2008. Based on current estimated gathering volumes and range of annual average commodity prices over the past five years, we estimate that gas produced on or isolated by the JAN lands represents approximately $20 million to $30 million of the West region’s annual gathering and processing revenue less related product costs.

Year-Over-Year Results

	Years Ended December 31,		
	2007	2006	2005
		(Millions)	
Segment revenues	$5,180	$4,159	$3,291
Segment profit			
Domestic gathering & processing	897	631	389
Venezuela	89	98	95
Other	174	16	42
Indirect general and administrative expense	(88)	(70)	(66)
Total	$1,072	$ 675	$ 460

In order to provide additional clarity, our management’s discussion and analysis of operating results separately reflects the portion of general and administrative expense not allocated to an asset group as *indirect general and administrative expense*. These charges represent any overhead cost not directly attributable to one of the specific asset groups noted in this discussion.

2007 vs. 2006

The $1,021 million, or 25 percent, increase in *segment revenues* is largely due to:

- A $528 million increase in revenues from the marketing of NGLs and olefins;
- A $303 million increase in revenues from our olefins production business;
- A $244 million increase in revenues associated with the production of NGLs.

These increases are partially offset by a $35 million decrease in fee revenues.

Segment costs and expenses increased $645 million, or 18 percent, primarily as a result of:

- A $491 million increase in NGL and olefin marketing purchases;
- A $257 million increase in costs from our olefins production business;
- A $37 million increase in operating expenses including higher depreciation, maintenance, gathering fuel expenses and operating taxes;
- $24 million higher general and administrative expenses;
- A $10 million loss on impairment of the Carbonate Trend pipeline and an $8 million loss on impairment of certain other assets;
- The absence of $11 million of net gains on the sales of assets in 2006.

These increases are partially offset by;

- The absence of a 2006 charge of $73 million related to our Gulf Liquids litigation (see Note 15 of Notes to Consolidated Financial Statements);
- A $95 million decrease in costs associated with the production of NGLs due primarily to lower natural gas prices;
- $12 million income in 2007 from a favorable litigation outcome.

The $397 million, or 59 percent, increase in Midstream's *segment profit* reflects $339 million higher NGL margins and the absence of the previously mentioned $73 million Gulf Liquids litigation charge in 2006, as well as the other previously described changes in *segment revenues* and *segment costs and expenses.* A more detailed analysis of the segment profit of Midstream's various operations is presented as follows.

Domestic gathering & processing

The $266 million increase in *domestic gathering and processing segment profit* includes a $308 million increase in the West region, partially offset by a $42 million decrease in the Gulf Coast region.

The $308 million increase in our West region's *segment profit* primarily results from higher NGL margins, higher processing fee based revenues and income from a favorable litigation outcome, partially offset by higher operating expenses and lower gathering fee revenues. The significant components of this increase include the following:

- NGL margins increased $326 million in 2007 compared to 2006. This increase was driven by an increase in average per unit NGL prices, a decrease in costs associated with the production of NGLs reflecting lower natural gas prices and higher volumes due primarily to new capacity on the fifth cryogenic train at our Opal plant.
- Processing fee revenues increased $12 million. Processing volumes are higher due to customers electing to take liquids and pay processing fees.
- $12 million income in 2007 from a favorable litigation outcome.
- Gathering fee revenues decreased $6 million due primarily to natural volume declines and the shutdown of the Ignacio plant in the fourth quarter of 2007 as a result of the fire.
- Operating expenses increased $21 million including $9 million in higher depreciation, $9 million in higher treating plant and gathering fuel due primarily to the expiration of a favorable gas purchase contract, $5 million related to gas imbalance revaluation losses in the current year compared to gains in the prior year, $5 million higher leased compression costs and $4 million higher costs related to the Jicarilla lease arrangement. These were partially offset by the absence of a $7 million accounts payable accrual adjustment in 2006 and $5 million in lower system product losses.

The $42 million decrease in the Gulf Coast region's *segment profit* is primarily a result of lower volumes from our deepwater facilities, losses on impairments, and the absence of gains on assets in 2006, partially offset by higher NGL margins and higher other fee revenues. The significant components of this decrease include the following:

- Fee revenues from our deepwater assets decreased $40 million due primarily to declines in producers' volumes.
- A $10 million loss on impairment of the Carbonate Trend pipeline and a $6 million loss on impairment of certain other assets.
- The absence of $8 million in gains on the sales of certain gathering assets and a processing plant in 2006 and $5 million lower involuntary conversion gains resulting from insurance proceeds used to rebuild the Cameron Meadows plant.
- NGL margins increased $14 million driven by higher NGL prices, partially offset by lower NGL recoveries and an increase in costs associated with the production of NGLs.
- Other fee revenues increased $8 million driven by higher water removal fees.

Venezuela

Segment profit for our Venezuela assets decreased $9 million. The decrease is primarily due to the absence of a $9 million gain from the settlement of a contract dispute in 2006, $6 million lower fee revenues due primarily to the discontinuance in 2007 of revenue recognition related to labor escalation receivables, $7 million higher operating expenses, and $8 million higher bad debt expense related to labor escalation receivables, partially offset by $19 million of higher currency exchange gains and $1 million higher equity earnings.

Other

The significant components of the $158 million increase in *segment profit* of our other operations include the following:

- The absence of the previously mentioned $73 million Gulf Liquids litigation charge in 2006;
- $46 million in higher margins from our olefins production business due primarily to the increase in ownership of the Geismar olefins facility in July 2007 and higher prices of NGL products produced in our Canadian olefins operations;
- $18 million in higher margins related to the marketing of olefins and $21 million in higher margins related to the marketing of NGLs due to more favorable changes in pricing while product was in transit during 2007 as compared to 2006;
- An $8 million reversal of a maintenance accrual (see below);
- $9 million higher Aux Sable equity earnings primarily due to favorable processing margins;
- $11 million higher Discovery equity earnings primarily due to higher NGL margins and volumes.

These increases are partially offset by:

- $19 million in higher foreign exchange losses related to the revaluation of current assets held in U.S. dollars within our Canadian operations;
- The absence of a $4 million favorable transportation settlement in 2006.

Effective January 1, 2007, we adopted FASB Staff Position (FSP) No. AUG AIR-1, *Accounting for Planned Major Maintenance Activities.* As a result, we recognized as other income an $8 million reversal of an accrual for major maintenance on our Geismar ethane cracker. We did not apply the FSP retrospectively because the impact to our first quarter 2007 and estimated full year 2007 earnings, as well as the impact to prior periods, is not material. We have adopted the deferral method for accounting for these costs going forward.

Indirect general and administrative expense

The $18 million, or 26 percent, increase in indirect general and administrative expense is due primarily to higher technical support services and other charges for various administrative support functions and higher employee expenses.

2006 vs. 2005

The $868 million, or 26 percent, increase in *segment revenues* is largely due to:

- A $561 million increase in crude marketing revenues, which is offset by a similar change in costs, resulting from additional deepwater production coming on-line in November 2005;
- A $165 million increase in revenues associated with the production of NGLs, primarily due to higher NGL prices combined with higher volumes;
- A $137 million increase in the marketing of NGLs and olefins, which is offset by a similar change in costs;
- An $83 million increase in fee-based revenues including $52 million in higher production handling revenues;
- A $44 million increase in revenues in our olefins unit due to higher volumes.

These increases were partially offset by an $84 million reduction in NGL revenues due to a change in classification of NGL transportation and fractionation expenses from costs of goods sold to net revenues (offset in costs and operating expenses).

Segment costs and expenses increased $688 million, or 23 percent, primarily as a result of:

- A $561 million increase in crude marketing purchases, which is offset by a similar change in revenues;
- A $137 million increase in NGL and olefins marketing purchases, offset by a similar change in revenues;
- An $82 million increase in operating expenses including an $11 million accounts payable accrual adjustment, higher system losses, depreciation, insurance expense, personnel and related benefit expenses, turbine overhauls, materials and supplies, compression and post-hurricane inspection and survey costs required by a government agency;
- A $59 million increase in other expense including the $73 million charge related to the Gulf Liquids litigation, partially offset by a $9 million favorable settlement of a contract dispute;
- A $20 million increase in costs associated with production in our olefins unit.

These increases were partially offset by:

- An $84 million reduction in NGL transportation and fractionation expenses due to the above-noted change in classification (offset in revenues);
- A $77 million decrease in plant fuel and costs associated with the production of NGLs due primarily to lower gas prices.

The $215 million, or 47 percent, increase in Midstream *segment profit* is primarily due to higher NGL margins, higher deepwater production handling revenues, higher gathering and processing revenues, higher margins from our olefins unit, and a settlement of an international contract dispute, and the absence of a $23 million impairment of our equity investment in Aux Sable Liquid Products L.P. (Aux Sable) recorded in 2005. These increases were largely offset by the $73 million charge related to the Gulf Liquids litigation contingency combined with higher operating costs and lower margins related to the marketing of olefins and NGLs. A more detailed analysis of the *segment profit* of Midstream's various operations is presented as follows.

Domestic gathering & processing

The $242 million increase in *domestic gathering and processing segment profit* includes a $138 million increase in the West region and a $104 million increase in the Gulf Coast region.

The $138 million increase in our West region's *segment profit* primarily results from higher product margins and higher gathering and processing revenues, partially offset by higher operating expenses. The significant components of this increase include the following:

- NGL margins increased $166 million compared to 2005. This increase was driven by a decrease in costs associated with the production of NGLs, an increase in average per unit NGL prices and higher volumes resulting from lower NGL recoveries during the fourth quarter of 2005 caused by intermittent periods of uneconomical market commodity prices and a power outage and associated operational issues at our Opal, Wyoming facility. NGL margins are defined as NGL revenues less BTU replacement cost, plant fuel, and transportation and fractionation expense.
- Gathering and processing fee revenues increased $26 million. Gathering fees are higher as a result of higher average per-unit gathering rates. Processing volumes are higher due to customers electing to take liquids and pay processing fees.
- Operating expenses increased $51 million including $11 million in higher net system product losses as a result of system gains in 2005 compared to losses in 2006, a $7 million accounts payable accrual adjustment; $8 million in higher personnel and related benefit expenses; $6 million in higher materials and supplies; $6 million in higher gathering fuel, $4 million in higher leased compression costs; $4 million in higher turbine overhaul costs; and $4 million in higher depreciation.

The $104 million increase in the Gulf Coast region's *segment profit* is primarily a result of higher NGL margins, higher volumes from our deepwater facilities, partially offset by higher operating expenses. The significant components of this increase include the following:

- NGL margins increased $77 million compared to 2005. This increase was driven by an increase in average per unit NGL prices and a decrease in costs associated with the production of NGLs.
- Fee revenues from our deepwater assets increased $52 million as a result of $51 million in higher volumes flowing across the Devils Tower facility and $22 million in higher Devils Tower unit-of-production rates recognized as a result of a new reserve study. These increases are partially offset by a $21 million decline in other gathering and production handling revenues due to volume declines in other areas.
- Operating expenses increased $25 million primarily as a result of $12 million in higher insurance costs, $4 million in higher depreciation expense on our deepwater assets, $3 million in higher net system product losses as a result of lower gain volumes in 2006, $2 million in post-hurricane inspection and survey costs required by a government agency, and a $1 million accounts payable accrual adjustment.

Venezuela

Segment profit for our Venezuela assets increased $3 million and includes $9 million resulting from the settlement of a contract dispute and $1 million in higher revenues due to higher natural gas volumes and prices at our compression facility. These are partially offset by $4 million in higher expenses related to higher insurance, personnel and contract labor costs and a $2 million increase in the reserve for uncollectible accounts.

Other

The $26 million decrease in *segment profit* of our other operations is largely due to the $73 million of charges related to the Gulf Liquids litigation contingency combined with $13 million in lower margins related to the marketing of olefins. The decrease also reflects $12 million in lower margins related to the marketing of NGLs due to more favorable changes in pricing while product was in transit during 2005 as compared to 2006. These were partially offset by the absence of a $23 million impairment of our equity investment in Aux Sable in 2005, $24 million in higher margins in our olefins unit, $7 million in higher earnings from our equity investment in

Discovery Producer Services, L.L.C. (Discovery), $7 million in higher fractionation, storage and other fee revenues, and a $4 million favorable transportation settlement.

Gas Marketing Services

Gas Marketing Services (Gas Marketing) primarily supports our natural gas businesses by providing marketing and risk management services, which include marketing and hedging the gas produced by Exploration & Production, and procuring fuel and shrink gas and hedging natural gas liquids sales for Midstream. In addition, Gas Marketing manages various natural gas-related contracts such as transportation, storage, and related hedges, including certain legacy natural gas contracts and positions, and provides services to third parties, such as producers.

Overview of 2007

Gas Marketing's operating results for 2007 were primarily driven by a loss of approximately $166 million related to certain legacy derivative natural gas contracts that we expect to assign to another party in 2008 under an asset transfer agreement that we executed in December 2007. In addition, a decrease in forward natural gas basis prices against a net long legacy derivative position contributed to the losses as well.

Outlook for 2008

For 2008, Gas Marketing intends to focus on providing services that support our natural gas businesses. Certain legacy natural gas contracts and positions from our former Power segment remain in the Gas Marketing segment. Gas Marketing's earnings may continue to reflect mark-to-market volatility from commodity-based derivatives that represent economic hedges but are not designated as hedges for accounting purposes or do not qualify for hedge accounting. However, this mark-to-market volatility is expected to be significantly reduced compared with previous levels.

Year-Over-Year Results

	Years Ended December 31,		
	2007	2006	2005
		(Millions)	
Realized revenues	$4,948	$5,185	$6,147
Net forward unrealized mark-to-market gains (losses)	(315)	(136)	188
Segment revenues	4,633	5,049	6,335
Costs and operating expenses	4,937	5,258	6,238
Gross margin	(304)	(209)	97
Selling, general and administrative (income) expense	13	(13)	(1)
Other (income) expense — net	20	(1)	89
Segment profit (loss)	$ (337)	$ (195)	$ 9

2007 vs. 2006

Realized revenues represent (1) revenue from the sale of natural gas and (2) gains and losses from the net financial settlement of derivative contracts. *Realized revenues* decreased $237 million primarily due to a decrease in net financial settlements of derivative contracts. This is partially offset by an increase in physical natural gas revenue as a result of a 9 percent increase in natural gas sales volumes partially offset by a 6 percent decrease in average prices on physical natural gas sales.

Net forward unrealized mark-to-market gains (losses) primarily represent changes in the fair values of certain legacy derivative contracts with a future settlement or delivery date that are not designated as hedges for accounting purposes or do not qualify for hedge accounting. A $156 million loss related to a legacy derivative natural gas sales contract, that we expect to assign to another party in 2008 under an asset transfer agreement that we executed in

December 2007, primarily caused the unfavorable change in *net forward unrealized mark-to-market gains (losses)*. Prior to the execution of the asset transfer agreement, we accounted for this legacy contract on an accrual basis under the normal purchases and normal sales exception of SFAS 133. Due to the pending assignment of the legacy contract, we no longer consider the contract to be in the normal course of business. Therefore, we recognized a loss to reflect the current negative fair value of the contract. In addition, losses on gas purchase contracts caused by a decrease in forward natural gas prices were greater in 2007 than in 2006.

The $321 million decrease in Gas Marketing's *costs and operating expenses* is primarily due to a 7 percent decrease in average prices on physical natural gas purchases, partially offset by a 4 percent increase in natural gas purchase volumes.

The unfavorable change in *selling, general and administrative (income) expense* is due primarily to the absence of a $25 million gain from the sale of certain receivables to a third party in 2006.

Other (income) expense — net in 2007 includes a $20 million accrual for litigation contingencies.

The $142 million increase in *segment loss* is primarily due to the loss recognized on a legacy derivative sales contract previously treated as a normal purchase and normal sale, a $20 million accrual for litigation contingencies, and the absence of a $25 million gain from the sale of certain receivables as described above, partially offset by an improvement in accrual gross margin.

2006 vs. 2005

Realized revenues decreased $962 million primarily due to a 17 percent decrease in average prices on physical natural gas sales.

The effect of a change in forward prices on legacy natural gas derivative contracts primarily caused the $324 million unfavorable change in *net forward unrealized mark-to-market gains (losses)*. A decrease in forward natural gas prices during 2006 caused losses on legacy net forward gas fixed-price purchase contracts, while an increase in forward natural gas prices during 2005 caused gains on legacy net forward gas fixed-price purchase contracts.

The $980 million decrease in Gas Marketing's *costs and operating expenses* is primarily due to an 18 percent decrease in average prices on physical natural gas purchases.

The favorable change in *selling, general and administrative (income) expense* is due primarily to increased gains from the sale of certain receivables to a third party. Gas Marketing recognized a $25 million gain in 2006 compared to a $10 million gain in 2005.

Other (income) expense — net in 2005 includes an $82 million accrual for estimated litigation contingencies, primarily associated with agreements reached to substantially resolve exposure related to natural gas price and volume reporting issues (see Note 15 of Notes to Consolidated Financial Statements) and a $5 million accrual for a regulatory settlement.

The $204 million change from a *segment profit* to a *segment loss* is primarily due to the effect of a change in forward prices on legacy natural gas derivative contracts, partially offset by favorable changes in *other (income) expense — net* described above.

Other

Year-Over-Year Operating Results

	Years Ended December 31,		
	2007	2006	2005
		(Millions)	
Segment revenues	$ 26	$ 27	$ 27
Segment loss	$ (1)	$ (13)	$(123)

2007 vs. 2006

The improvement in *segment loss* for 2007 is primarily driven by $5 million of net gains on the sale of land.

2006 vs. 2005

Other *segment loss* for 2005 includes $87 million of impairment charges, of which $38 million was recorded during the fourth quarter, related to our investment in Longhorn. In a related matter, we wrote off $4 million of capitalized project costs associated with Longhorn. We also recorded $24 million of equity losses associated with our investment in Longhorn. Partially offsetting these charges and losses was a $9 million fourth quarter gain on the sale of land.

Energy Trading Activities

Fair Value of Trading and Nontrading Derivatives

The chart below reflects the fair value of derivatives held for trading purposes as of December 31, 2007. We have presented the fair value of assets and liabilities by the period in which they would be realized under their contractual terms and not as a result of a sale. We have reported the fair value of a portion of these derivatives in assets and liabilities of discontinued operations. (See Note 2 of Notes to Consolidated Financial Statements.)

Net Assets (Liabilities) — Trading
(Millions)

To be Realized in 1-12 Months (Year 1)	To be Realized in 13-36 Months (Years 2-3)	To be Realized in 37-60 Months (Years 4-5)	To be Realized in 61-120 Months (Years 6-10)	To be Realized in 121+ Months (Years 11+)	Net Fair Value
$(1)	$ (1)	$ (1)	$ (1)	$ —	$ (4)

As the table above illustrates, we are not materially engaged in trading activities. However, we hold a substantial portfolio of nontrading derivative contracts. Nontrading derivative contracts are those that hedge or could possibly hedge forecasted transactions on an economic basis. We have designated certain of these contracts as cash flow hedges of Exploration & Production's forecasted sales of natural gas production and Midstream's forecasted sales of natural gas liquids under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS 133). Of the total fair value of nontrading derivatives, SFAS 133 cash flow hedges had a net liability value of $268 million as of December 31, 2007. The chart below reflects the fair value of derivatives held for nontrading purposes as of December 31, 2007, for Gas Marketing Services, Exploration & Production, Midstream, and nontrading derivatives reported in assets and liabilities of discontinued operations.

Net Assets (Liabilities) — Nontrading
(Millions)

To be Realized in 1-12 Months (Year 1)	To be Realized in 13-36 Months (Years 2-3)	To be Realized in 37-60 Months (Years 4-5)	To be Realized in 61-120 Months (Years 6-10)	To be Realized in 121+ Months (Years 11+)	Net Fair Value
$(87)	$ (268)	$ (8)	$ (1)	$ —	$ (364)

Methods of Estimating Fair Value

Most of the derivatives we hold settle in active periods and markets in which quoted market prices are available. These include futures contracts, option contracts, swap agreements and physical commodity purchases and sales in the commodity markets in which we transact. While an active market may not exist for the entire period, quoted prices can generally be obtained for natural gas through 2012.

These prices reflect current economic and regulatory conditions and may change because of market conditions. The availability of quoted market prices in active markets varies between periods and commodities based upon changes in market conditions. The ability to obtain quoted market prices also varies greatly from region to region. The time periods noted above are an estimation of aggregate availability of quoted prices. An immaterial portion of our total net derivative liability value of $368 million relates to periods in which active quotes cannot be obtained. We estimate energy commodity prices in these illiquid periods by incorporating information about commodity prices in actively quoted markets, quoted prices in less active markets, and other market fundamental analysis. Modeling and other valuation techniques, however, are not used significantly in determining the fair value of our derivatives.

Counterparty Credit Considerations

We include an assessment of the risk of counterparty nonperformance in our estimate of fair value for all contracts. Such assessment considers (1) the credit rating of each counterparty as represented by public rating agencies such as Standard & Poor's and Moody's Investors Service, (2) the inherent default probabilities within these ratings, (3) the regulatory environment that the contract is subject to and (4) the terms of each individual contract.

Risks surrounding counterparty performance and credit could ultimately impact the amount and timing of expected cash flows. We continually assess this risk. We have credit protection within various agreements to call on additional collateral support if necessary. At December 31, 2007, we held collateral support, including letters of credit, of $215 million.

We also enter into master netting agreements to mitigate counterparty performance and credit risk. During 2007 and 2006, we did not incur any significant losses due to recent counterparty bankruptcy filings.

The gross credit exposure from our derivative contracts, a portion of which is included in assets of discontinued operations (see Note 2 of Notes to Consolidated Financial Statements), as of December 31, 2007, is summarized below.

Counterparty Type	Investment Grade(a)	Total
	(Millions)	
Gas and electric utilities	$ 78	$ 79
Energy marketers and traders	224	1,328
Financial institutions	1,302	1,302
Other	—	1
	$ 1,604	2,710
Credit reserves		(1)
Gross credit exposure from derivatives		$2,709

We assess our credit exposure on a net basis to reflect master netting agreements in place with certain counterparties. We offset our credit exposure to each counterparty with amounts we owe the counterparty under derivative contracts. The net credit exposure from our derivatives as of December 31, 2007, is summarized below.

Counterparty Type	Investment Grade(a)	Total
	(Millions)	
Gas and electric utilities	$ 17	$ 17
Energy marketers and traders	18	20
Financial institutions	45	45
Other	—	—
	$ 80	82
Credit reserves		(1)
Net credit exposure from derivatives		$ 81

(a) We determine investment grade primarily using publicly available credit ratings. We include counterparties with a minimum Standard & Poor's rating of BBB— or Moody's Investors Service rating of Baa3 in investment grade. We also classify counterparties that have provided sufficient collateral, such as cash, standby letters of credit, adequate parent company guarantees, and property interests, as investment grade.

Trading Policy

We have policies and procedures that govern our trading and risk management activities. These policies cover authority and delegation thereof in addition to control requirements, authorized commodities and term and exposure limitations. Value-at-risk is limited in aggregate and calculated at a 95 percent confidence level.

Management's Discussion and Analysis of Financial Condition

Outlook

We believe we have, or have access to, the financial resources and liquidity necessary to meet future requirements for working capital, capital and investment expenditures and debt payments while maintaining a sufficient level of liquidity to reasonably protect against unforeseen circumstances requiring the use of funds. We also expect to maintain our investment grade status. In 2008, we expect to maintain liquidity from cash and cash equivalents and unused revolving credit facilities of at least $1 billion. We maintain adequate liquidity to manage margin requirements related to significant movements in commodity prices, unplanned capital spending needs, near term scheduled debt payments, and litigation and other settlements. We expect to fund capital and investment expenditures, debt payments, dividends, stock repurchases and working capital requirements through cash flow from operations, which is currently estimated to be between $2.3 billion and $2.7 billion in 2008, proceeds from debt issuances and sales of units of Williams Partners L.P. and Williams Pipeline Partners L.P., as well as cash and cash equivalents on hand as needed.

We enter 2008 positioned for continued growth through disciplined investments in our natural gas businesses. Examples of this planned growth include:

- Exploration & Production will continue to maintain its development drilling program in its key basins of Piceance, Powder River, San Juan, Arkoma, and Fort Worth.
- Gas Pipeline will continue to expand its system to meet the demand of growth markets.
- Midstream will continue to pursue significant deepwater production commitments and expand capacity in the western United States.

We estimate capital and investment expenditures will total approximately $2.6 billion to $2.9 billion in 2008. As a result of increasing our development drilling program, $1.45 billion to $1.65 billion of the total estimated 2008 capital expenditures is related to Exploration & Production. Also within the total estimated expenditures for 2008 is approximately $180 million to $260 million for compliance and maintenance-related projects at Gas Pipeline, including Clean Air Act compliance. Commitments for construction and acquisition of property, plant and equipment are approximately $484 million at December 31, 2007.

Potential risks associated with our planned levels of liquidity and the planned capital and investment expenditures discussed above include:

- Lower than expected levels of cash flow from operations due to commodity pricing volatility. To mitigate this exposure, Exploration & Production has fixed-price hedges for approximately 70 MMcfe per day of its expected 2008 production. In addition, Exploration & Production has collar agreements for 2008 which hedge approximately 397 MMcfe per day of expected 2008 production.
- Sensitivity of margin requirements associated with our marginable commodity contracts. As of December 31, 2007, we estimate our exposure to additional margin requirements through 2008 to be no more than $125 million, using a statistical analysis at a 99 percent confidence level.

- Exposure associated with our efforts to resolve regulatory and litigation issues (see Note 15 of Notes to Consolidated Financial Statements).
- The impact of a general economic downturn, including any associated volatility in the credit markets and our access to liquidity and the capital markets.

In August 2006, the Pension Protection Act of 2006 was signed into law. The Act makes significant changes to the requirements for employer-sponsored retirement plans, including revisions affecting the funding of defined benefit pension plans beginning in 2008. We have assessed the impact of the legislation on our future funding requirements and do not expect a significant increase in minimum funding requirements over current levels, assuming long-term rates of return on assets and current discount rates do not experience a significant decline.

Overview

In February 2007, Exploration & Production entered into a five-year unsecured credit agreement with certain banks in order to reduce margin requirements related to our hedging activities as well as lower transaction fees. Under the credit agreement, Exploration & Production is not required to post collateral as long as the value of its domestic natural gas reserves, as determined under the provisions of the agreement, exceeds by a specified amount certain of its obligations including any outstanding debt and the aggregate out-of-the-money positions on hedges entered into under the credit agreement. Exploration & Production is subject to additional covenants under the credit agreement including restrictions on hedge limits, the creation of liens, the incurrence of debt, the sale of assets and properties, and making certain payments, such as dividends, under certain circumstances.

On April 4, 2007, Northwest Pipeline retired $175 million of 8.125 percent senior notes due 2010. Northwest Pipeline paid premiums of approximately $7 million in conjunction with the early debt retirement.

On April 5, 2007, Northwest Pipeline issued $185 million aggregate principal amount of 5.95 percent senior unsecured notes due 2017 to certain institutional investors in a private debt placement. Northwest Pipeline initiated an exchange offer on July 26, 2007, which expired on August 23, 2007. Northwest Pipeline received full participation in the exchange offer. (See Note 11 of Notes to Consolidated Financial Statements.)

In July 2007, our Board of Directors authorized the repurchase of up to $1 billion of our common stock. We intend to purchase shares of our stock from time to time in open market transactions or through privately negotiated or structured transactions at our discretion, subject to market conditions and other factors. This stock-repurchase program does not have an expiration date. We plan to fund this program with cash on hand. In 2007, we purchased approximately 16 million shares for $526 million under the program at an average cost of $33.08 per share.

During third-quarter 2007, we formed Williams Pipeline Partners L.P. (WMZ) to own and operate natural gas transportation and storage assets. In January 2008, WMZ completed its initial public offering of 16.25 million common units at a price of $20.00 per unit. In February 2008, the underwriters also exercised their right to purchase an additional 1.65 million common units at the same price. A subsidiary of ours serves as the general partner of WMZ. The initial asset of the partnership is a 35 percent interest in Northwest Pipeline GP, formerly Northwest Pipeline Corporation. Upon completion of the transaction, we hold approximately 47.7 percent of the interests in WMZ, including the interests of the general partner.

In December 2007, Williams Partners L.P. acquired certain of our membership interests in Wamsutter LLC, the limited liability company that owns the Wamsutter system, from us for $750 million. Williams Partners L.P. completed the transaction after successfully closing a public equity offering of 9.25 million common units that yielded net proceeds of approximately $335 million. The partnership financed the remainder of the purchase price primarily through utilizing $250 million of term loan borrowings and issuing approximately $157 million of common units to us. The $250 million term loan is under Williams Partners L.P.'s new $450 million five-year senior unsecured credit facility that became effective simultaneous with the closing of the Wamsutter transaction. The remaining $200 million of capacity under the new facility is available for revolving credit borrowings.

In December 2007, we repurchased $213 million of our 7.125 percent senior unsecured notes due September 2011 and $22 million of our 8.125 percent senior unsecured notes due March 2012. In conjunction with these early retirements, we paid premiums of approximately $19 million. These premiums, as well as related fees and expenses are recorded as *early debt retirement costs* in the Consolidated Statement of Income.

Credit ratings

On March 19, 2007, Standard & Poor's raised our senior unsecured debt rating from a BB− to a BB with a stable ratings outlook. On May 21, 2007, Standard & Poor's revised its ratings outlook to positive from stable. On November 9, 2007, Standard & Poor's raised our senior unsecured debt rating from a BB to a BB+ and our corporate credit rating from a BB+ to a BBB− with a ratings outlook of stable. With respect to Standard & Poor's, a rating of "BBB" or above indicates an investment grade rating. A rating below "BBB" indicates that the security has significant speculative characteristics. A "BB" rating indicates that Standard & Poor's believes the issuer has the capacity to meet its financial commitment on the obligation, but adverse business conditions could lead to insufficient ability to meet financial commitments. Standard & Poor's may modify its ratings with a "+" or a "− " sign to show the obligor's relative standing within a major rating category.

On May 21, 2007, Moody's Investors Service placed our ratings under review for possible upgrade. On November 15, 2007, Moody's Investors Service raised our senior unsecured debt rating from a Ba2 to a Baa3 with a ratings outlook of stable. With respect to Moody's, a rating of "Baa" or above indicates an investment grade rating. A rating below "Baa" is considered to have speculative elements. A "Ba" rating indicates an obligation that is judged to have speculative elements and is subject to substantial credit risk. The "1", "2" and "3" modifiers show the relative standing within a major category. A "1" indicates that an obligation ranks in the higher end of the broad rating category, "2" indicates a mid-range ranking, and "3" ranking at the lower end of the category.

On May 21, 2007, Fitch Ratings revised its ratings outlook to positive from stable. On November 20, 2007, Fitch Ratings raised our senior unsecured debt rating from a BB+ to a BBB− with a ratings outlook of stable. With respect to Fitch, a rating of "BBB" or above indicates an investment grade rating. A rating below "BBB" is considered speculative grade. A "BB" rating from Fitch indicates that there is a possibility of credit risk developing, particularly as the result of adverse economic change over time; however, business or financial alternatives may be available to allow financial commitments to be met. Fitch may add a "+" or a "− " sign to show the obligor's relative standing within a major rating category.

Liquidity

Our internal and external sources of liquidity include cash generated from our operations, bank financings, and proceeds from the issuance of long-term debt and equity securities, and proceeds from asset sales. While most of our sources are available to us at the parent level, others are available to certain of our subsidiaries, including equity and debt issuances from Williams Partners L.P. and Williams Pipeline Partners L.P. Our ability to raise funds in the capital markets will be impacted by our financial condition, interest rates, market conditions, and industry conditions.

Available Liquidity

	Year Ended December 31, 2007 (Millions)
Cash and cash equivalents*	$ 1,699
Securities	20
Available capacity under our four unsecured revolving and letter of credit facilities totaling $1.2 billion	858
Available capacity under our $1.5 billion unsecured revolving and letter of credit facility**	1,222
Available capacity under Williams Partners L.P.'s $450 million five-year senior unsecured credit facility (see previous discussion)	200
	$ 3,999

* *Cash and cash equivalents* includes $10 million of funds received from third parties as collateral. The obligation for these amounts is reported in *accrued liabilities* on the Consolidated Balance Sheet. Also included is $475 million of cash and cash equivalents that is being utilized by certain subsidiary and international operations.

** Northwest Pipeline and Transco each have access to $400 million under this facility to the extent not utilized by us. In 2007, Northwest Pipeline borrowed $250 million under this facility to retire matured notes, and in January 2008, Transco borrowed $100 million.

In addition to the above, Northwest Pipeline and Transco have shelf registration statements available for the issuance of up to $350 million aggregate principal amount of debt securities. If the credit rating of Northwest Pipeline or Transco is below investment grade for all credit rating agencies, they can only use their shelf registration statements to issue debt if such debt is guaranteed by us.

Williams Partners L.P. has a shelf registration statement available for the issuance of approximately $1.2 billion aggregate principal amount of debt and limited partnership unit securities.

In addition, at the parent-company level, we have a shelf registration statement that allows us to issue publicly registered debt and equity securities as needed.

In February 2007, Exploration & Production entered into a five-year unsecured credit agreement with certain banks which serves to reduce our usage of cash and other credit facilities for margin requirements related to our hedging activities as well as lower transaction fees. (See Note 11 of Notes to Consolidated Financial Statements.)

On May 9, 2007, we amended our $1.5 billion unsecured credit facility extending the maturity date from May 1, 2009 to May 1, 2012. Applicable borrowing rates and commitment fees for investment grade credit ratings were also modified.

Sources (Uses) of Cash

	Years Ended December 31,		
	2007	2006	2005
		(Millions)	
Net cash provided (used) by:			
Operating activities	$ 2,237	$ 1,890	$1,450
Financing activities	(511)	1,103	36
Investing activities	(2,296)	(2,321)	(819)
Increase (decrease) in cash and cash equivalents	$ (570)	$ 672	$ 667

Operating Activities

Our *net cash provided by operating activities* in 2007 increased from 2006 due primarily to the increase in our operating results and the absence of a $145 million securities litigation settlement payment in 2006. These increases are partially offset by increased income tax payments in 2007 and other changes in working capital.

Our *net cash provided by operating activities* in 2006 increased from 2005 due largely to higher operating income at Midstream, partially offset by a $145 million securities litigation settlement payment in fourth quarter 2006.

Financing Activities

2007

See Overview, within this section, for a discussion of 2007 debt issuances, retirements, stock repurchases, and additional financing by Williams Partners L.P.

Quarterly dividends paid on common stock increased from $.09 to $.10 per common share during the second quarter of 2007 and totaled $233 million for year ended December 31, 2007.

2006

- Transco issued $200 million aggregate principal amount of 6.4 percent senior unsecured notes due 2016.
- Northwest Pipeline issued $175 million aggregate principal amount of 7 percent senior unsecured notes due 2016.
- Williams Partners L.P. acquired our interest in Williams Four Corners LLC for $1.6 billion. The acquisition was completed after Williams Partners L.P. successfully closed a $150 million private debt offering of 7.5 percent senior unsecured notes due 2011, a $600 million private debt offering of 7.25 percent senior unsecured notes due 2017, $350 million of common and Class B units, and equity offerings of $519 million in net proceeds.
- We paid $489 million to retire a secured floating-rate term loan due in 2008.
- We paid $26 million in premiums related to the conversion of $220 million of 5.5 percent junior subordinated convertible debentures into common stock.
- Quarterly dividends paid on common stock increased from $.075 to $.09 per share during the second quarter of 2006 and totaled $207 million for the year ended December 31, 2006.

2005

- We retired $200 million of 6.125 percent notes issued by Transco, which matured January 15, 2005.
- We received $273 million in *proceeds from the issuance of common stock* purchased under the FELINE PACS equity forward contracts.
- We completed an initial public offering of approximately 40 percent of our interest in Williams Partners L.P. resulting in net proceeds of $111 million.
- Quarterly dividends paid on common stock increased from $.05 to $.075 per common share during the third quarter of 2005 and totaled $143 million for the year ended December 31, 2005.

Investing Activities

2007

- Capital expenditures totaled $2.8 billion and were primarily related to Exploration & Production's drilling activity, mostly in the Piceance basin.
- We received $496 million of gross proceeds from the sale of substantially all of our power business.
- We purchased $304 million and received $353 million from the sale of auction rate securities.

2006

- Capital expenditures totaled $2.5 billion and were primarily related to Exploration & Production's drilling activity, mostly in the Piceance basin, and Northwest Pipeline's capacity replacement project.
- We purchased $386 million and received $414 million from the sale of auction rate securities.

2005

- Capital expenditures totaled $1.3 billion and were primarily related to Exploration & Production's drilling activity, mostly in the Piceance basin, and Gas Pipeline's normal maintenance and compliance.
- We received $310 million in proceeds from the Gulfstream recapitalization.

- We purchased $224 million and received $138 million from the sale of auction rate securities.
- Northwest Pipeline received an $88 million contract termination payment, representing reimbursement of the net book value of the related assets.
- We received $55 million proceeds from the sale of our note with Williams Communications Group, our previously owned subsidiary.

Off-balance sheet financing arrangements and guarantees of debt or other commitments

We have various other guarantees and commitments which are disclosed in Notes 2, 3, 10, 11, 14, and 15 of Notes to Consolidated Financial Statements. We do not believe these guarantees or the possible fulfillment of them will prevent us from meeting our liquidity needs.

Contractual Obligations

The table below summarizes the maturity dates of our contractual obligations, including obligations related to discontinued operations.

	2008	2009-2010	2011-2012	Thereafter	Total
			(Millions)		
Long-term debt, including current portion:					
Principal	$ 138	$ 92	$2,531	$ 5,160	$ 7,921
Interest	585	1,142	1,011	4,743	7,481
Capital leases	6	6	—	—	12
Operating leases	84	94	28	19	225
Purchase obligations(1)	1,351	1,347	1,297	2,859	6,854
Other long-term liabilities, including current portion:					
Physical and financial derivatives(2)(3)	478	661	269	321	1,729
Other(4)(5)	5	1	—	—	6
Total	$2,647	$3,343	$5,136	$ 13,102	$24,228

(1) Includes $4.4 billion of natural gas purchase obligations at market prices at our Exploration & Production segment. The purchased natural gas can be sold at market prices.

(2) The obligations for physical and financial derivatives are based on market information as of December 31, 2007. Because market information changes daily and has the potential to be volatile, significant changes to the values in this category may occur.

(3) Expected offsetting cash inflows of $5.6 billion at December 31, 2007, resulting from product sales or net positive settlements, are not reflected in these amounts. In addition, product sales may require additional purchase obligations to fulfill sales obligations that are not reflected in these amounts.

(4) Does not include estimated contributions to our pension and other postretirement benefit plans. We made contributions to our pension and other postretirement benefit plans of $56 million in 2007 and $57 million in 2006. In 2008, we expect to contribute approximately $56 million to these plans (see Note 7 of Notes to Consolidated Financial Statements), including $40 million to our tax-qualified pension plans. There were no minimum funding requirements to our tax-qualified pension plans in 2007 or 2006, and we do not expect any minimum funding requirements in 2008. We anticipate that future contributions will not vary significantly from recent historical contributions, assuming actual results do not differ significantly from estimated results for assumptions such as discount rates, returns on plan assets, retirement rates, mortality and other significant assumptions, and assuming no further changes in current and prospective legislation and regulations. Based on these anticipated levels of future contributions, we do not expect to trigger any minimum funding requirements in the future; however, we may elect to make contributions to increase the funded status of our plans.

(5) On January 1, 2007, we adopted FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes." As of December 31, 2007, we have accrued approximately $76 million for unrecognized tax benefits. We cannot make reasonably reliable estimates of the timing of the future payments of these liabilities. Therefore, these liabilities have been excluded from the table above. See Note 5 of Notes to Consolidated Financial Statements for information regarding our contingent tax liability reserves.

Effects of Inflation

Our operations have benefited from relatively low inflation rates. Approximately 42 percent of our gross property, plant and equipment is at Gas Pipeline and the remainder is at other operating units. Gas Pipeline is subject to regulation, which limits recovery to historical cost. While amounts in excess of historical cost are not recoverable under current FERC practices, we anticipate being allowed to recover and earn a return based on increased actual cost incurred to replace existing assets. Cost-based regulation, along with competition and other market factors, may limit our ability to recover such increased costs. For the other operating units, operating costs are influenced to a greater extent by both competition for specialized services and specific price changes in oil and natural gas and related commodities than by changes in general inflation. Crude, natural gas, and natural gas liquids prices are particularly sensitive to OPEC production levels and/or the market perceptions concerning the supply and demand balance in the near future. However, our exposure to these price changes is reduced through the use of hedging instruments.

Environmental

We are a participant in certain environmental activities in various stages including assessment studies, cleanup operations and/or remedial processes at certain sites, some of which we currently do not own. (See Note 15 of Notes to Consolidated Financial Statements.) We are monitoring these sites in a coordinated effort with other potentially responsible parties, the U.S. Environmental Protection Agency (EPA), or other governmental authorities. We are jointly and severally liable along with unrelated third parties in some of these activities and solely responsible in others. Current estimates of the most likely costs of such activities are approximately $46 million, all of which are recorded as liabilities on our balance sheet at December 31, 2007. We will seek recovery of approximately $13 million of the accrued costs through future natural gas transmission rates. The remainder of these costs will be funded from operations. During 2007, we paid approximately $14 million for cleanup and/or remediation and monitoring activities. We expect to pay approximately $15 million in 2008 for these activities. Estimates of the most likely costs of cleanup are generally based on completed assessment studies, preliminary results of studies or our experience with other similar cleanup operations. At December 31, 2007, certain assessment studies were still in process for which the ultimate outcome may yield significantly different estimates of most likely costs. Therefore, the actual costs incurred will depend on the final amount, type and extent of contamination discovered at these sites, the final cleanup standards mandated by the EPA or other governmental authorities, and other factors.

We are subject to the federal Clean Air Act and to the federal Clean Air Act Amendments of 1990, which require the EPA to issue new regulations. We are also subject to regulation at the state and local level. In September 1998, the EPA promulgated rules designed to mitigate the migration of ground-level ozone in certain states. In March 2004 and June 2004, the EPA promulgated additional regulation regarding hazardous air pollutants, which may impose additional controls. Capital expenditures necessary to install emission control devices on our Transco gas pipeline system to comply with rules were approximately $3 million in 2007 and are estimated to be between $25 million and $30 million through 2010. The actual costs incurred will depend on the final implementation plans developed by each state to comply with these regulations. We consider these costs on our Transco system associated with compliance with these environmental laws and regulations to be prudent costs incurred in the ordinary course of business and, therefore, recoverable through its rates.

Item 7A. ***Quantitative and Qualitative Disclosures About Market Risk***

Interest Rate Risk

Our current interest rate risk exposure is related primarily to our debt portfolio. The majority of our debt portfolio is comprised of fixed rate debt in order to mitigate the impact of fluctuations in interest rates. The maturity of our long-term debt portfolio is partially influenced by the expected lives of our operating assets.

The tables below provide information about our interest rate risk-sensitive instruments as of December 31, 2007 and 2006. Long-term debt in the tables represents principal cash flows, net of (discount) premium, and weighted-average interest rates by expected maturity dates. The fair value of our publicly traded long-term debt is valued using indicative year-end traded bond market prices. Private debt is valued based on the prices of similar securities with similar terms and credit ratings.

	2008	2009	2010	2011	2012	Thereafter(1)	Total	Fair Value December 31, 2007
	(Dollars in millions)							
Long-term debt, including current portion(4):								
Fixed rate	$ 53	$ 41	$ 27	$948	$971	$ 5,111	$7,151	$ 7,994
Interest rate	7.7%	7.7%	7.4%	7.4%	7.3%	7.7%		
Variable rate	$ 85	$ 12	$ 12	$ 7	$605(5)	$ 18	$ 739	$ 735
Interest rate(2)								

	2007	2008	2009	2010	2011	Thereafter(1)	Total	Fair Value December 31, 2006
	(Dollars in millions)							
Long-term debt, including current portion(4):								
Fixed rate	$381	$153	$ 41	$205	$1,161	$ 5,922	$7,863	$ 8,343
Interest rate	7.7%	7.7%	7.7%	7.5%	7.6%	7.8%		
Variable rate	$ 10	$ 85	$ 12	$ 12	$ 7	$ 23	$ 149	$ 137
Interest rate(3)								

(1) Includes unamortized discount and premium.

(2) The interest rate at December 31, 2007, is LIBOR plus 1 percent.

(3) The interest rate at December 31, 2006 was LIBOR plus 1 percent.

(4) Excludes capital leases.

(5) Includes Transco's subsequent refinancing of its $100 million notes, due on January 15, 2008, under our $1.5 billion revolving credit facility. (See Note 11 of Notes to Consolidated Financial Statements.)

Commodity Price Risk

We are exposed to the impact of fluctuations in the market price of natural gas and natural gas liquids, as well as other market factors, such as market volatility and commodity price correlations. We are exposed to these risks in connection with our owned energy-related assets, our long-term energy-related contracts and our proprietary trading activities. We manage the risks associated with these market fluctuations using various derivatives and nonderivative energy-related contracts. The fair value of derivative contracts is subject to changes in energy-commodity market prices, the liquidity and volatility of the markets in which the contracts are transacted, and changes in interest rates. We measure the risk in our portfolios using a value-at-risk methodology to estimate the potential one-day loss from adverse changes in the fair value of the portfolios.

Value at risk requires a number of key assumptions and is not necessarily representative of actual losses in fair value that could be incurred from the portfolios. Our value-at-risk model uses a Monte Carlo method to simulate hypothetical movements in future market prices and assumes that, as a result of changes in commodity prices, there is a 95 percent probability that the one-day loss in fair value of the portfolios will not exceed the value at risk. The simulation method uses historical correlations and market forward prices and volatilities. In applying the value-at-risk methodology, we do not consider that the simulated hypothetical movements affect the positions or would cause any potential liquidity issues, nor do we consider that changing the portfolio in response to market conditions could affect market prices and could take longer than a one-day holding period to execute. While a one-day holding period has historically been the industry standard, a longer holding period could more accurately represent the true market risk given market liquidity and our own credit and liquidity constraints.

We segregate our derivative contracts into trading and nontrading contracts, as defined in the following paragraphs. We calculate value at risk separately for these two categories. Derivative contracts designated as normal purchases or sales under SFAS 133 and nonderivative energy contracts have been excluded from our estimation of value at risk.

Trading

Our trading portfolio consists of derivative contracts entered into for purposes other than economically hedging our commodity price-risk exposure. Our value at risk for contracts held for trading purposes was approximately $1 million at both December 31, 2007 and 2006. During the year ended December 31, 2007, our value at risk for these contracts ranged from a high of $2 million to a low of $1 million.

Nontrading

Our nontrading portfolio consists of derivative contracts that hedge or could potentially hedge the price risk exposure from the following activities:

Segment	Commodity Price Risk Exposure
Exploration & Production	• Natural gas sales
Midstream	• Natural gas purchases
	• NGL sales
Gas Marketing Services	• Natural gas purchases and sales

The value at risk for derivative contracts held for nontrading purposes was $24 million at December 31, 2007 and $12 million at December 31, 2006. During the year ended December 31, 2007, our value at risk for these contracts ranged from a high of $24 million to a low of $7 million. The increase in value at risk reflects the impact on our nontrading portfolio of the sale of substantially all of our power business in November 2007.

Certain of the derivative contracts held for nontrading purposes are accounted for as cash flow hedges under SFAS 133. Though these contracts are included in our value-at-risk calculation, any change in the fair value of these hedge contracts would generally not be reflected in earnings until the associated hedged item affects earnings.

Foreign Currency Risk

We have international investments that could affect our financial results if the investments incur a permanent decline in value as a result of changes in foreign currency exchange rates and/or the economic conditions in foreign countries.

International investments accounted for under the cost method totaled $24 million at December 31, 2007, and $42 million at December 31, 2006. These investments are primarily in nonpublicly traded companies for which it is not practicable to estimate fair value. We believe that we can realize the carrying value of these investments considering the status of the operations of the companies underlying these investments. If a 20 percent change occurred in the value of the underlying currencies of these investments against the U.S. dollar, the fair value at December 31, 2007, could change by approximately $5 million assuming a direct correlation between the currency fluctuation and the value of the investments.

Net assets of consolidated foreign operations, whose functional currency is the local currency, are located primarily in Canada and approximate 7 percent and 6 percent of our net assets at December 31, 2007 and 2006, respectively. These foreign operations do not have significant transactions or financial instruments denominated in other currencies. However, these investments do have the potential to impact our financial position, due to fluctuations in these local currencies arising from the process of re-measuring the local functional currency into the U.S. dollar. As an example, a 20 percent change in the respective functional currencies against the U.S. dollar could have changed *stockholders' equity* by approximately $88 million at December 31, 2007.

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Item 8. ***Financial Statements and Supplementary Data***

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Williams' management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934) and for the assessment of the effectiveness of internal control over financial reporting. Our internal control system was designed to provide reasonable assurance to our management and board of directors regarding the preparation and fair presentation of financial statements in accordance with accounting principles generally accepted in the United States. Our internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets; (ii) provide reasonable assurance that transactions are recorded as to permit preparation of financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorization of our management and board of directors; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on our financial statements.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Our management assessed the effectiveness of Williams' internal control over financial reporting as of December 31, 2007. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control — Integrated Framework.* Management's assessment included an evaluation of the design of our internal control over financial reporting and testing of the operational effectiveness of our internal control over financial reporting. Based on our assessment we believe that, as of December 31, 2007, Williams' internal control over financial reporting is effective based on those criteria.

Ernst & Young LLP, our independent registered public accounting firm, has audited our internal control over financial reporting, as stated in their report which is included in this Annual Report on Form 10-K.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The Board of Directors and Stockholders of
The Williams Companies, Inc.

We have audited The Williams Companies, Inc.'s internal control over financial reporting as of December 31, 2007, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). The Williams Companies, Inc.'s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, The Williams Companies, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of The Williams Companies, Inc. as of December 31, 2007 and 2006, and the related consolidated statements of income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2007 of The Williams Companies, Inc. and our report dated February 22, 2008 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Tulsa, Oklahoma
February 22, 2008

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders of
The Williams Companies, Inc.

We have audited the accompanying consolidated balance sheet of The Williams Companies, Inc. as of December 31, 2007 and 2006, and the related consolidated statements of income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2007. Our audits also included the financial statement schedule listed in the index at Item 15(a). These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of The Williams Companies, Inc. at December 31, 2007 and 2006, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2007, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

As explained in Note 5 to the consolidated financial statements, effective January 1, 2007 the Company adopted FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes, an Interpretation of FASB Statement No. 109*. Also, as explained in Note 1 to the consolidated financial statements, effective January 1, 2006, the Company adopted Statement of Financial Accounting Standards No. 123(R), *Share-Based Payment*.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), The Williams Companies, Inc.'s internal control over financial reporting as of December 31, 2007, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 22, 2008 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Tulsa, Oklahoma
February 22, 2008

THE WILLIAMS COMPANIES, INC.

CONSOLIDATED STATEMENT OF INCOME

	Years Ended December 31,		
	2007	2006	2005
	(Millions, except per-share amounts)		
Revenues:			
Exploration & Production	$ 2,093	$ 1,488	$ 1,269
Gas Pipeline	1,610	1,348	1,413
Midstream Gas & Liquids	5,180	4,159	3,291
Gas Marketing Services	4,633	5,049	6,335
Other	26	27	27
Intercompany eliminations	(2,984)	(2,695)	(2,554)
Total revenues	10,558	9,376	9,781
Segment costs and expenses:			
Costs and operating expenses	8,079	7,566	7,885
Selling, general and administrative expenses	471	389	277
Other (income) expense — net	(18)	34	57
Total segment costs and expenses	8,532	7,989	8,219
General corporate expenses	161	132	145
Securities litigation settlement and related costs	—	167	9
Operating income (loss):			
Exploration & Production	731	530	568
Gas Pipeline	622	430	542
Midstream Gas & Liquids	1,011	635	455
Gas Marketing Services	(337)	(195)	9
Other	(1)	(13)	(12)
General corporate expenses	(161)	(132)	(145)
Securities litigation settlement and related costs	—	(167)	(9)
Total operating income	1,865	1,088	1,408
Interest accrued	(685)	(670)	(667)
Interest capitalized	32	17	7
Investing income	257	168	25
Early debt retirement costs	(19)	(31)	—
Minority interest in income of consolidated subsidiaries	(90)	(40)	(26)
Other income — net	11	26	27
Income from continuing operations before income taxes and cumulative effect of change in accounting principle	1,371	558	774
Provision for income taxes	524	211	301
Income from continuing operations	847	347	473
Income (loss) from discontinued operations	143	(38)	(157)
Income before cumulative effect of change in accounting principle	990	309	316
Cumulative effect of change in accounting principle	—	—	(2)
Net income	$ 990	$ 309	$ 314
Basic earnings (loss) per common share:			
Income from continuing operations	$ 1.42	$ .58	$ .82
Income (loss) from discontinued operations	.24	(.06)	(.27)
Income before cumulative effect of change in accounting principle	1.66	.52	.55
Cumulative effect of change in accounting principle	—	—	—
Net income	$ 1.66	$ .52	$ .55
Weighted-average shares (thousands)	596,174	595,053	570,420
Diluted earnings (loss) per common share:			
Income from continuing operations	$ 1.40	$ .57	$ .79
Income (loss) from discontinued operations	.23	(.06)	(.26)
Income before cumulative effect of change in accounting principle	1.63	.51	.53
Cumulative effect of change in accounting principle	—	—	—
Net income	$ 1.63	$ .51	$ .53
Weighted-average shares (thousands)	609,866	608,627	605,847

See accompanying notes.

THE WILLIAMS COMPANIES, INC.

CONSOLIDATED BALANCE SHEET

	December 31, 2007	December 31, 2006
	(Dollars in millions, except per-share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,699	$ 2,269
Accounts and notes receivable (net of allowance of $27 in 2007 and $15 in 2006)	1,192	981
Inventories	209	238
Derivative assets	1,736	1,286
Assets of discontinued operations	185	837
Deferred income taxes	199	337
Other current assets and deferred charges	318	374
Total current assets	5,538	6,322
Investments	901	866
Property, plant and equipment — net	15,981	14,158
Derivative assets	859	1,844
Goodwill	1,011	1,011
Assets of discontinued operations	—	565
Other assets and deferred charges	771	636
Total assets	$25,061	$25,402
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 1,131	$ 906
Accrued liabilities	1,158	1,353
Derivative liabilities	1,824	1,304
Liabilities of discontinued operations	175	739
Long-term debt due within one year	143	392
Total current liabilities	4,431	4,694
Long-term debt	7,757	7,622
Deferred income taxes	2,996	2,880
Derivative liabilities	1,139	1,920
Liabilities of discontinued operations	—	147
Other liabilities and deferred income	933	985
Contingent liabilities and commitments (Note 15)		
Minority interests in consolidated subsidiaries	1,430	1,081
Stockholders' equity:		
Common stock (960 million shares authorized at $1 par value; 608 million shares issued at December 31, 2007, and 603 million shares issued at December 31, 2006)	608	603
Capital in excess of par value	6,748	6,605
Accumulated deficit	(293)	(1,034)
Accumulated other comprehensive loss	(121)	(60)
	6,942	6,114
Less treasury stock, at cost (22 million shares of common stock in 2007 and 6 million shares of common stock in 2006)	(567)	(41)
Total stockholders' equity	6,375	6,073
Total liabilities and stockholders' equity	$25,061	$25,402

See accompanying notes.

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THE WILLIAMS COMPANIES, INC.

CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY

	Common Stock	Capital in Excess of Par Value	Accumulated Deficit	Accumulated Other Comprehensive Loss	Other	Treasury Stock	Total
	(Dollars in millions, except per-share amounts)						
Balance, December 31, 2004	$ 564	$ 6,006	$ (1,307)	$ (244)	$ (22)	$ (41)	$4,956
Comprehensive income:							
Net income — 2005	—	—	314	—	—	—	314
Other comprehensive loss:							
Net unrealized losses on cash flow hedges, net of reclassification adjustments	—	—	—	(66)	—	—	(66)
Foreign currency translation adjustments	—	—	—	11	—	—	11
Minimum pension liability adjustment	—	—	—	1	—	—	1
Total other comprehensive loss							(54)
Total comprehensive income							260
Issuance of common stock and settlement of forward contracts as a result of FELINE PACS exchange	11	262	—	—	—	—	273
Cash dividends — Common stock ($.25 per share)	—	—	(143)	—	—	—	(143)
Allowance for and repayment of stockholders' notes	—	—	—	—	17	—	17
Stock award transactions, including tax benefit	4	60	—	—	—	—	64
Balance, December 31, 2005	579	6,328	(1,136)	(298)	(5)	(41)	5,427
Comprehensive income:							
Net income — 2006	—	—	309	—	—	—	309
Other comprehensive income:							
Net unrealized gains on cash flow hedges, net of reclassification adjustments	—	—	—	394	—	—	394
Foreign currency translation adjustments	—	—	—	(4)	—	—	(4)
Minimum pension liability adjustment	—	—	—	(1)	—	—	(1)
Total other comprehensive income							389
Total comprehensive income							698
Adjustment to initially apply SFAS No. 158, net of tax:							
Pension benefits:							
Prior service cost	—	—	—	(4)	—	—	(4)
Net actuarial loss	—	—	—	(150)	—	—	(150)
Minimum pension liability	—	—	—	5	—	—	5
Other postretirement benefits:							
Prior service cost	—	—	—	(4)	—	—	(4)
Net actuarial gain	—	—	—	2	—	—	2
Issuance of common stock from 5.5% debentures conversion (Note 12)	20	193	—	—	—	—	213
Cash dividends — Common stock ($.35 per share)	—	—	(207)	—	—	—	(207)
Repayment of stockholders' notes	—	—	—	—	5	—	5
Stock award transactions, including tax benefit	4	84	—	—	—	—	88
Balance, December 31, 2006	603	6,605	(1,034)	(60)	—	(41)	6,073
Comprehensive income:							
Net income — 2007	—	—	990	—	—	—	990
Other comprehensive loss:							
Net unrealized losses on cash flow hedges, net of reclassification adjustments	—	—	—	(177)	—	—	(177)
Foreign currency translation adjustments	—	—	—	53	—	—	53
Pension benefits:							
Net actuarial gain	—	—	—	53	—	—	53
Other postretirement benefits:							
Prior service cost	—	—	—	1	—	—	1
Net actuarial gain	—	—	—	9	—	—	9
Total other comprehensive loss							(61)
Total comprehensive income							929
Cash dividends — Common stock ($.39 per share)	—	—	(233)	—	—	—	(233)
FIN 48 adjustment (Note 5)	—	—	(17)	—	—	—	(17)
Purchase of treasury stock (Note 12)	—	—	—	—	—	(526)	(526)
Stock award transactions, including tax benefit	5	143	—	—	—	—	148
Other	—	—	1	—	—	—	1
Balance, December 31, 2007	$ 608	$ 6,748	$ (293)	$ (121)	$ —	$ (567)	$6,375

See accompanying notes.

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THE WILLIAMS COMPANIES, INC.

CONSOLIDATED STATEMENT OF CASH FLOWS

	Years Ended December 31, 2007	2006	2005
		(Millions)	
OPERATING ACTIVITIES:			
Net income	$ 990	$ 309	$ 314
Adjustments to reconcile to net cash provided by operations:			
Cumulative effect of change in accounting principle	—	—	2
Reclassification of deferred net hedge gains to earnings related to sale of power business	(429)	—	—
Depreciation, depletion and amortization	1,082	866	740
Provision (benefit) for deferred income taxes	370	154	(47)
Provision for loss on investments, property and other assets	162	26	119
Net (gain) loss on dispositions of assets and business	16	(23)	(59)
Early debt retirement costs	19	31	—
Minority interest in income of consolidated subsidiaries	90	40	26
Amortization of stock-based awards	70	44	13
Cash provided (used) by changes in current assets and liabilities:			
Accounts and notes receivable	(122)	386	(242)
Inventories	29	31	(10)
Margin deposits and customer margin deposits payable	(135)	98	86
Other current assets and deferred charges	(10)	(30)	(8)
Accounts payable	26	(184)	233
Accrued liabilities	(200)	(110)	27
Changes in current and noncurrent derivative assets and liabilities	370	303	174
Other, including changes in noncurrent assets and liabilities	(91)	(51)	82
Net cash provided by operating activities	2,237	1,890	1,450
FINANCING ACTIVITIES:			
Proceeds from long-term debt	684	1,299	—
Payments of long-term debt	(806)	(777)	(251)
Proceeds from issuance of common stock	56	34	310
Proceeds from sale of limited partner units of consolidated partnership	333	863	111
Tax benefit of stock-based awards	32	16	—
Dividends paid	(233)	(207)	(143)
Purchase of treasury stock	(526)	—	—
Payments for debt issuance costs and amendment fees	(4)	(37)	(30)
Premiums paid on early debt retirements and tender offer	(27)	(26)	—
Dividends and distributions paid to minority interests	(75)	(36)	(21)
Changes in cash overdrafts	52	(25)	63
Other — net	3	(1)	(3)
Net cash provided (used) by financing activities	(511)	1,103	36
INVESTING ACTIVITIES:			
Property, plant and equipment:			
Capital expenditures	(2,816)	(2,509)	(1,299)
Net proceeds from dispositions	12	23	47
Proceeds from contract termination payment	—	3	88
Changes in accounts payable and accrued liabilities	(52)	105	65
Purchases of investments/advances to affiliates	(60)	(49)	(116)
Purchases of auction rate securities	(304)	(386)	(224)
Proceeds from sales of auction rate securities	353	414	138
Proceeds from sales of businesses	471	—	31
Proceeds from dispositions of investments and other assets	92	62	64
Proceeds received on sale of note from WilTel	—	—	55
Proceeds from Gulfstream recapitalization	—	—	310
Other — net	8	16	22
Net cash used by investing activities	(2,296)	(2,321)	(819)
Increase (decrease) in cash and cash equivalents	(570)	672	667
Cash and cash equivalents at beginning of year	2,269	1,597	930
Cash and cash equivalents at end of year	$ 1,699	$ 2,269	$ 1,597

See accompanying notes.

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1. Description of Business, Basis of Presentation, and Summary of Significant Accounting Policies

Description of Business

Operations of our company are located principally in the United States and are organized into the following reporting segments: Exploration & Production, Gas Pipeline, Midstream Gas & Liquids (Midstream), and Gas Marketing Services (Gas Marketing).

Exploration & Production includes natural gas development, production and gas management activities primarily in the Rocky Mountain and Mid-Continent regions of the United States and oil and natural gas interests in Argentina.

Gas Pipeline is comprised primarily of two interstate natural gas pipelines, as well as investments in natural gas pipeline-related companies. The Gas Pipeline operating segments have been aggregated for reporting purposes and include Northwest Pipeline GP (Northwest Pipeline), formerly Northwest Pipeline Corporation, which extends from the San Juan basin in northwestern New Mexico and southwestern Colorado to Oregon and Washington, and Transcontinental Gas Pipe Line Corporation (Transco), which extends from the Gulf of Mexico region to the northeastern United States. In addition, we own a 50 percent interest in Gulfstream Natural Gas System L.L.C. (Gulfstream). Gulfstream is a natural gas pipeline system extending from the Mobile Bay area in Alabama to markets in Florida.

Midstream is comprised of natural gas gathering and processing and treating facilities in the Rocky Mountain and Gulf Coast regions of the United States, oil gathering and transportation facilities in the Gulf Coast region of the United States, majority-owned natural gas compression facilities in Venezuela, and assets in Canada, consisting primarily of a natural gas liquids extraction facility and a fractionation plant.

Gas Marketing primarily supports our natural gas businesses by providing marketing and risk management services, which include marketing and hedging the gas produced by Exploration & Production, and procuring fuel and shrink gas and hedging natural gas liquids sales for Midstream. In addition, Gas Marketing manages various natural gas-related contracts such as transportation, storage, and related hedges, and provides services to third parties, such as producers.

Basis of Presentation

In accordance with the provisions related to discontinued operations within Statement of Financial Accounting Standards (SFAS) No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" (SFAS No. 144), the accompanying consolidated financial statements and notes reflect the results of operations and financial position of our power business as discontinued operations. (See Note 2.) These operations include a 7,500-megawatt portfolio of power-related contracts that were sold to Bear Energy, LP, a unit of The Bear Stearns Companies, Inc. and our natural gas-fired electric generating plant located in Hazleton, Pennsylvania (Hazleton), in addition to other power-related assets.

Unless indicated otherwise, the information in the Notes to the Consolidated Financial Statements relates to our continuing operations.

Williams Partners L.P. is a limited partnership engaged in the business of gathering, transporting and processing natural gas and fractionating and storing natural gas liquids. We currently own approximately 23.6 percent of Williams Partners L.P., including the interests of the general partner, which is wholly owned by us, and incentive distribution rights. Considering the presumption of control of the general partner in accordance with Emerging Issues Task Force (EITF) Issue No. 04-5, "Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights," Williams Partners L.P. is consolidated within our Midstream segment.

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Summary of Significant Accounting Policies

Principles of consolidation

The consolidated financial statements include the accounts of our corporate parent and our majority-owned or controlled subsidiaries and investments. We apply the equity method of accounting for investments in unconsolidated companies in which we and our subsidiaries own 20 to 50 percent of the voting interest, or otherwise exercise significant influence over operating and financial policies of the company.

Use of estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and accompanying notes. Actual results could differ from those estimates.

Significant estimates and assumptions include:

- Impairment assessments of investments, long-lived assets and goodwill;
- Litigation-related contingencies;
- Valuations of derivatives;
- Environmental remediation obligations;
- Hedge accounting correlations and probability;
- Realization of deferred income tax assets;
- Valuation of Exploration & Production's reserves;
- Asset retirement obligations;
- Pension and postretirement valuation variables.

These estimates are discussed further throughout these notes.

Cash and cash equivalents

Cash and cash equivalents includes demand and time deposits, money market funds, and other marketable securities with maturities of three months or less when acquired.

Restricted cash

Restricted cash within *current assets* is included in *other current assets and deferred charges* in the Consolidated Balance Sheet and consists primarily of collateral required by certain loan agreements for our Venezuelan operations, and escrow accounts established to fund payments required by our California settlement. (See Note 15). Restricted cash within noncurrent assets is included in *other assets and deferred charges* in the Consolidated Balance Sheet and relates primarily to certain borrowings by our Venezuelan operations as previously mentioned and letters of credit. We do not expect this cash to be released within the next twelve months. The current and noncurrent restricted cash is primarily invested in short-term money market accounts with financial institutions.

The classification of restricted cash is determined based on the expected term of the collateral requirement and not necessarily the maturity date of the investment.

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Auction rate securities

Auction rate securities are instruments with long-term underlying maturities, but for which an auction is conducted periodically, as specified, to reset the interest rate and allow investors to buy or sell the instruments. Because auctions generally occur more often than annually, and because we hold these investments in order to meet short-term liquidity needs, we classify auction rate securities as short-term and include them in *other current assets and deferred charges* on our Consolidated Balance Sheet. Our Consolidated Statement of Cash Flows reflects the gross amount of the *purchases of auction rate securities* and the *proceeds from sales of auction rate securities.*

Accounts receivable

Accounts receivable are carried on a gross basis, with no discounting, less the allowance for doubtful accounts. We estimate the allowance for doubtful accounts based on existing economic conditions, the financial conditions of the customers and the amount and age of past due accounts. Receivables are considered past due if full payment is not received by the contractual due date. Interest income related to past due accounts receivable is generally recognized at the time full payment is received or collectibility is assured. Past due accounts are generally written off against the allowance for doubtful accounts only after all collection attempts have been exhausted.

Inventory valuation

All *inventories* are stated at the lower of cost or market. We determine the cost of certain natural gas inventories held by Transco using the last-in, first-out (LIFO) cost method. We determine the cost of the remaining inventories primarily using the average-cost method.

Property, plant and equipment

Property, plant and equipment is recorded at cost. We base the carrying value of these assets on estimates, assumptions and judgments relative to capitalized costs, useful lives and salvage values.

As regulated entities, Northwest Pipeline and Transco provide for depreciation using the straight-line method at Federal Energy Regulatory Commission (FERC)-prescribed rates. Depreciation rates used for major regulated gas plant facilities for all years presented, are as follows:

Category of Property	Depreciation Rates
Gathering facilities	.01% - 3.8%
Storage facilities	.15% - 3.3%
Onshore transmission facilities	.15% - 7.25%
Offshore transmission facilities	.01% - 1.5%
General plant	2.95% - 50%

Depreciation for nonregulated entities is provided primarily on the straight-line method over estimated useful lives, except as noted below for oil and gas exploration and production activities. The estimated useful lives are as follows:

Category of Property	Estimated Useful Lives (In years)
Natural gas gathering and processing facilities	15 to 40
Transportation equipment	3 to 10
Building and improvements	5 to 45
Right of way	4 to 40
Office furnishings, computer software and hardware and other	3 to 30

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Gains or losses from the ordinary sale or retirement of property, plant and equipment for regulated pipelines are credited or charged to accumulated depreciation; other gains or losses are recorded in *other (income) expense — net* included in *operating income*.

Ordinary maintenance and repair costs are generally expensed as incurred. Costs of major renewals and replacements are capitalized as *property, plant, and equipment — net*.

Oil and gas exploration and production activities are accounted for under the successful efforts method. Costs incurred in connection with the drilling and equipping of exploratory wells, as applicable, are capitalized as incurred. If proved reserves are not found, such costs are charged to expense. Other exploration costs, including lease rentals, are expensed as incurred. All costs related to development wells, including related production equipment and lease acquisition costs, are capitalized when incurred. *Depreciation, depletion and amortization* is provided under the units of production method on a field basis.

Unproved properties with individually significant acquisition costs are assessed annually, or as conditions warrant, and any impairment in value is recognized. Unproved properties with acquisition costs that are not individually significant are aggregated, and the portion of such costs estimated to be nonproductive, based on historical experience or other information, is amortized over the average holding period. If the unproved properties are determined to be productive, the appropriate related costs are transferred to proved oil and gas properties.

Proved properties, including developed and undeveloped, and costs associated with unproven reserves, are assessed for impairment using estimated future cash flows on a field basis. Estimating future cash flows involves the use of complex judgments such as estimation of the proved and unproven oil and gas reserve quantities, risk associated with the different categories of oil and gas reserves, timing of development and production, expected future commodity prices, capital expenditures, and production costs.

We record an asset and a liability upon incurrence equal to the present value of each expected future asset retirement obligation (ARO). The ARO asset is depreciated in a manner consistent with the depreciation of the underlying physical asset. We measure changes in the liability due to passage of time by applying an interest method of allocation. This amount is recognized as an increase in the carrying amount of the liability and as a corresponding accretion expense included in *other (income) expense — net* included in *operating income*, except for regulated entities, for which the liability is offset by a regulatory asset.

Goodwill

Goodwill represents the excess of cost over fair value of the assets of businesses acquired. It is evaluated annually for impairment by first comparing our management's estimate of the fair value of a reporting unit with its carrying value, including goodwill. If the carrying value of the reporting unit exceeds its fair value, a computation of the implied fair value of the goodwill is compared with its related carrying value. If the carrying value of the reporting unit goodwill exceeds the implied fair value of that goodwill, an impairment loss is recognized in the amount of the excess. We have *goodwill* of approximately $1 billion at December 31, 2007, and 2006, at our Exploration & Production segment.

When a reporting unit is sold or classified as held for sale, any goodwill of that reporting unit is included in its carrying value for purposes of determining any impairment or gain/loss on sale. If a portion of a reporting unit with goodwill is sold or classified as held for sale and that asset group represents a business, a portion of the reporting unit's goodwill is allocated to and included in the carrying value of that asset group. None of the operations sold during 2007 or 2005 represented reporting units with goodwill or businesses within reporting units to which goodwill was required to be allocated.

Judgments and assumptions are inherent in our management's estimate of undiscounted future cash flows used to determine the estimate of the reporting unit's fair value. The use of alternate judgments and/or assumptions could result in the recognition of different levels of impairment charges in the financial statements.

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Treasury stock

Treasury stock purchases are accounted for under the cost method whereby the entire cost of the acquired stock is recorded as treasury stock. Gains and losses on the subsequent reissuance of shares are credited or charged to *capital in excess of par value* using the average-cost method.

Derivative instruments and hedging activities

We utilize derivatives to manage our commodity price risk. These instruments consist primarily of futures contracts, swap agreements, option contracts, and forward contracts involving short- and long-term purchases and sales of a physical energy commodity. We execute most of these transactions on an organized commodity exchange or in over-the-counter markets in which quoted prices exist for active periods. For contracts with terms that exceed the time period for which actively quoted prices are available, we determine fair value by estimating commodity prices during the illiquid periods utilizing internally developed valuations incorporating information obtained from commodity prices in actively quoted markets, quoted prices in less active markets, prices reflected in current transactions, and other market fundamental analysis.

We report the fair value of derivatives, except for those for which the normal purchases and normal sales exception has been elected, on the Consolidated Balance Sheet in *derivative assets* and *derivative liabilities* as either current or noncurrent. We determine the current and noncurrent classification based on the timing of expected future cash flows of individual contracts.

The accounting for changes in the fair value of a commodity derivative is governed by SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," (SFAS No. 133), as amended and depends on whether the derivative has been designated in a hedging relationship and whether we have elected the normal purchases and normal sales exception. The accounting for the change in fair value can be summarized as follows:

Derivative Treatment	Accounting Method
Normal purchases and normal sales exception	Accrual accounting
Designated in a qualifying hedging relationship	Hedge accounting
All other derivatives	Mark-to-market accounting

We may elect the normal purchases and normal sales exception for certain short- and long-term purchases and sales of a physical energy commodity. Under accrual accounting, any change in the fair value of these derivatives is not reflected on the balance sheet after the initial election of the exception.

We have also designated a hedging relationship for certain commodity derivatives. For a derivative to qualify for designation in a hedging relationship, it must meet specific criteria and we must maintain appropriate documentation. We establish hedging relationships pursuant to our risk management policies. We evaluate the hedging relationships at the inception of the hedge and on an ongoing basis to determine whether the hedging relationship is, and is expected to remain, highly effective in achieving offsetting changes in fair value or cash flows attributable to the underlying risk being hedged. We also regularly assess whether the hedged forecasted transaction is probable of occurring. If a derivative ceases to be or is no longer expected to be highly effective, or if we believe the likelihood of occurrence of the hedged forecasted transaction is no longer probable, hedge accounting is discontinued prospectively, and future changes in the fair value of the derivative are recognized currently in *revenues*.

For commodity derivatives designated as a cash flow hedge, the effective portion of the change in fair value of the derivative is reported in *other comprehensive income (loss)* and reclassified into earnings in the period in which the hedged item affects earnings. Any ineffective portion of the derivative's change in fair value is recognized currently in *revenues*. Gains or losses deferred in *accumulated other comprehensive loss* associated with terminated derivatives, derivatives that cease to be highly effective hedges, derivatives for which the forecasted transaction is reasonably possible but no longer probable of occurring, and cash flow hedges that have been otherwise

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

discontinued remain in *accumulated other comprehensive loss* until the hedged item affects earnings. If it becomes probable that the forecasted transaction designated as the hedged item in a cash flow hedge will not occur, any gain or loss deferred in *accumulated other comprehensive loss* is recognized in *revenues* at that time. The change in likelihood is a judgmental decision that includes qualitative assessments made by management.

For commodity derivatives that are not designated in a hedging relationship, and for which we have not elected the normal purchases and normal sales exception, we report changes in fair value currently in *revenues*.

Certain gains and losses on derivative instruments included in the Consolidated Statement of Income are netted together to a single net gain or loss, while other gains and losses are reported on a gross basis. Gains and losses recorded on a net basis include:

- Unrealized gains and losses on all derivatives that are not designated as hedges and for which we have not elected the normal purchases and normal sales exception;
- The ineffective portion of unrealized gains and losses on derivatives that are designated as cash flow hedges;
- Realized gains and losses on all derivatives that settle financially;
- Realized gains and losses on derivatives held for trading purposes;
- Realized gains and losses on derivatives entered into as a pre-contemplated buy/sell arrangement.

Realized gains and losses on derivatives that require physical delivery, and which are not held for trading purposes nor were entered into as a pre-contemplated buy/sell arrangement, are recorded on a gross basis. In reaching our conclusions on this presentation, we evaluated the indicators in EITF Issue No. 99-19 "Reporting Revenue Gross as a Principal versus as an Agent," including whether we act as principal in the transaction; whether we have the risks and rewards of ownership, including credit risk; and whether we have latitude in establishing prices.

Gas Pipeline revenues

Revenues from the transportation of gas are recognized in the period the service is provided, and revenues for sales of products are recognized in the period of delivery. Gas Pipeline is subject to FERC regulations and, accordingly, certain revenues collected may be subject to possible refunds upon final orders in pending rate cases. Gas Pipeline records estimates of rate refund liabilities considering Gas Pipeline and other third-party regulatory proceedings, advice of counsel and estimated total exposure, as discounted and risk weighted, as well as collection and other risks.

Exploration & Production revenues

Revenues from the domestic production of natural gas in properties for which Exploration & Production has an interest with other producers are recognized based on the actual volumes sold during the period. Any differences between volumes sold and entitlement volumes, based on Exploration & Production's net working interest, that are determined to be nonrecoverable through remaining production are recognized as accounts receivable or accounts payable, as appropriate. Cumulative differences between volumes sold and entitlement volumes are not significant.

All other revenues

Revenues generally are recorded when services are performed or products have been delivered.

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Impairment of long-lived assets and investments

We evaluate the long-lived assets of identifiable business activities for impairment when events or changes in circumstances indicate, in our management's judgment, that the carrying value of such assets may not be recoverable. When an indicator of impairment has occurred, we compare our management's estimate of undiscounted future cash flows attributable to the assets to the carrying value of the assets to determine whether an impairment has occurred. We apply a probability-weighted approach to consider the likelihood of different cash flow assumptions and possible outcomes including selling in the near term or holding for the remaining estimated useful life. If an impairment of the carrying value has occurred, we determine the amount of the impairment recognized in the financial statements by estimating the fair value of the assets and recording a loss for the amount that the carrying value exceeds the estimated fair value.

For assets identified to be disposed of in the future and considered held for sale in accordance with SFAS No. 144, we compare the carrying value to the estimated fair value less the cost to sell to determine if recognition of an impairment is required. Until the assets are disposed of, the estimated fair value, which includes estimated cash flows from operations until the assumed date of sale, is recalculated when related events or circumstances change.

We evaluate our investments for impairment when events or changes in circumstances indicate, in our management's judgment, that the carrying value of such investments may have experienced an other-than-temporary decline in value. When evidence of loss in value has occurred, we compare our estimate of fair value of the investment to the carrying value of the investment to determine whether an impairment has occurred. If the estimated fair value is less than the carrying value and we consider the decline in value to be other-than-temporary, the excess of the carrying value over the fair value is recognized in the consolidated financial statements as an impairment.

Judgments and assumptions are inherent in our management's estimate of undiscounted future cash flows and an asset's fair value. Additionally, judgment is used to determine the probability of sale with respect to assets considered for disposal. The use of alternate judgments and/or assumptions could result in the recognition of different levels of impairment charges in the consolidated financial statements.

Capitalization of interest

We capitalize interest during construction on major projects with construction periods of at least three months and a total project cost in excess of $1 million. Interest is capitalized on borrowed funds and, where regulation by the FERC exists, on internally generated funds as a component of *other income — net*. The rates used by regulated companies are calculated in accordance with FERC rules. Rates used by unregulated companies are based on the average interest rate on debt. The benefit of interest capitalized on internally generated funds for regulated entities is reported in *other income — net* below *operating income*.

Employee stock-based awards

Prior to January 1, 2006, we accounted for stock-based awards to employees and nonmanagement directors (see Note 13) under the recognition and measurement provisions of Accounting Principles Board (APB) Opinion No. 25, "Accounting for Stock Issued to Employees," and related interpretations, as permitted by SFAS No. 123, "Accounting for Stock-Based Compensation" (SFAS No. 123). Compensation cost for stock options was not recognized in the Consolidated Statement of Income for the years prior to 2006 as all options granted had an exercise price equal to the market value of the underlying common stock on the date of the grant. Prior to January 1, 2006, compensation cost was recognized for restricted stock units. Effective January 1, 2006, we adopted the fair

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

value recognition provisions of SFAS No. 123(R), "Share-Based Payment" (SFAS No. 123(R)), using the modified-prospective method. Under this method, compensation cost recognized in periods subsequent to December 31, 2005, includes: (1) compensation cost for all share-based payments granted through December 31, 2005, but for which the requisite service period had not been completed as of December 31, 2005, based on the grant date fair value estimated in accordance with the provisions of SFAS No. 123, and (2) compensation cost for most share-based payments granted subsequent to December 31, 2005, based on the grant date fair value estimated in accordance with the provisions of SFAS No. 123(R). The performance targets for certain performance-based restricted stock units have not been established and therefore expense is not currently recognized. Expense associated with these performance-based awards will be recognized in future periods when performance targets are established. Results for prior periods have not been restated.

Total stock-based compensation expense for the years ending December 31, 2007 and 2006, was $70 million and $44 million, respectively, of which $9 million and $3 million, respectively, is included in *income (loss) from discontinued operations*. The 2006 amount reflects a reduction of $.3 million of previously recognized compensation cost for restricted stock units related to the estimated number of awards expected to be forfeited. This adjustment is not considered material for reporting as a cumulative effect of a change in accounting principle. Measured but unrecognized stock-based compensation expense at December 31, 2007, was approximately $62 million, which does not include the effect of estimated forfeitures of $3 million. This amount is comprised of approximately $7 million related to stock options and approximately $55 million related to restricted stock units. These amounts are expected to be recognized over a weighted-average period of 1.9 years.

The following table illustrates the effect on *net income* and *earnings per common share* for the year ending December 31, 2005, if we had applied the fair value recognition provisions of SFAS No. 123 to options granted. For purposes of this pro forma disclosure, the value of the options was estimated using a Black-Scholes option pricing model and amortized to expense over the vesting period of the options.

	Year Ended December 31, 2005 (Dollars in millions, except per share amounts)
Net income, as reported	$ 314
Add: Stock-based employee compensation expense included in the consolidated statement of income, net of related tax effects	9
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(17)
Pro forma net income	$ 306
Earnings per common share:	
Basic — as reported	$ .55
Basic — pro forma	$ .54
Diluted — as reported	$ .53
Diluted — pro forma	$ .52

Pro forma amounts for 2005 include compensation expense from awards of our company stock made in 2005, 2004, 2003, and 2002.

Income taxes

We include the operations of our subsidiaries in our consolidated tax return. Deferred income taxes are computed using the liability method and are provided on all temporary differences between the financial basis and the tax basis of our assets and liabilities. Our management's judgment and income tax assumptions are used to determine the levels, if any, of valuation allowances associated with deferred tax assets.

Earnings (loss) per common share

Basic earnings (loss) per common share is based on the sum of the weighted-average number of common shares outstanding and issuable restricted stock units. *Diluted earnings (loss) per common share* includes any dilutive effect of stock options, nonvested restricted stock units and, for applicable periods presented, convertible debt, unless otherwise noted.

Foreign currency translation

Certain of our foreign subsidiaries and equity method investees use their local currency as their functional currency. These foreign currencies include the Canadian dollar, British pound and Euro. Assets and liabilities of certain foreign subsidiaries and equity investees are translated at the spot rate in effect at the applicable reporting date, and the combined statements of operations and our share of the results of operations of our equity affiliates are translated into the U.S. dollar at the average exchange rates in effect during the applicable period. The resulting cumulative translation adjustment is recorded as a separate component of *other comprehensive income (loss)*.

Transactions denominated in currencies other than the functional currency are recorded based on exchange rates at the time such transactions arise. Subsequent changes in exchange rates result in transaction gains and losses which are reflected in the Consolidated Statement of Income.

Issuance of equity of consolidated subsidiary

Sales of residual equity interests in a consolidated subsidiary are accounted for as capital transactions. No adjustments to capital are made for sales of preferential interests in a subsidiary. No gain or loss is recognized on these transactions.

Recent Accounting Standards

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements" (SFAS No. 157). This Statement establishes a framework for fair value measurements in the financial statements by providing a definition of fair value, provides guidance on the methods used to estimate fair value and expands disclosures about fair value measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007. In February 2008, the FASB issued FASB Staff Position (FSP) No. FAS 157-2, permitting entities to delay application of SFAS No. 157 to fiscal years beginning after November 15, 2008 for nonfinancial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). SFAS No. 157 requires two distinct transition approaches; (i) cumulative-effect adjustment to beginning retained earnings for certain financial instrument transactions and (ii) prospectively as of the date of adoption through earnings or other comprehensive income, as applicable. On January 1, 2008, we partially applied SFAS No. 157 through a prospective transition for our assets and liabilities that are measured at fair value on a recurring basis, primarily our commodity derivatives, with no material impact to our Consolidated Financial Statements. We did not have financial instrument transactions that required a cumulative-effect adjustment to beginning retained earnings upon the adoption of SFAS No. 157. Beginning January 1, 2009, we will apply SFAS No. 157 fair value requirements to nonfinancial assets and nonfinancial liabilities that are not recognized or disclosed on a recurring basis. SFAS No. 157 expands disclosures about assets and liabilities measured at fair value on a recurring basis effective beginning with first-quarter 2008 reporting.

In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities — Including an Amendment of FASB Statement No. 115" (SFAS No. 159). SFAS No. 159 establishes a fair value option permitting entities to elect to measure eligible financial instruments and certain other items at fair value. Unrealized gains and losses on items for which the fair value option has been elected will be reported in earnings. The fair value option may be applied on an instrument-by-instrument basis, is irrevocable and is applied to the entire instrument. SFAS No. 159 is effective as of the beginning of the first fiscal year beginning after November 15, 2007, and should not be applied retrospectively to fiscal years beginning prior to the effective date. On the adoption date, an entity may elect the fair value option for eligible items existing at that date and the adjustment for the initial remeasurement of those items to fair value should be reported as a cumulative effect adjustment to the opening balance of retained earnings. Subsequent to January 1, 2008, the fair value option can only be elected when a financial instrument or certain other item is entered into. On January 1, 2008, we did not elect the fair value option for any existing eligible financial instruments or certain other items.

In April 2007, the FASB issued an FSP on a previously issued FASB Interpretation (FIN), FSP FIN 39-1, "Amendment of FASB Interpretation No. 39." FSP FIN 39-1 amends FIN 39, "Offsetting of Amounts Related to Certain Contracts (as amended)" by requiring the offsetting of fair value amounts recognized for the right to reclaim or obligation to return cash collateral if the related derivative instruments have been offset pursuant to a master netting arrangement. The FSP requires disclosure of the accounting policy related to offsetting fair value amounts pursuant to master netting arrangements as well as disclosure of amounts recognized for the right to reclaim or obligation to return cash collateral. This FSP is effective for fiscal years beginning after November 15, 2007, with early application permitted, and is applied retrospectively as a change in accounting principle for all financial statements presented. We do not offset derivative instruments subject to master netting arrangements for financial statement presentation purposes; therefore, there is no change to our accounting policy and no financial impact on our Consolidated Financial Statements.

In June 2007, the FASB ratified EITF Issue No. 06-11 "Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards" (EITF 06-11). EITF 06-11 requires that the income tax benefits received on dividends or dividend equivalents paid to employees holding equity-classified nonvested shares be recorded as additional paid-in capital when the dividends or dividend equivalents are charged to retained earnings pursuant to SFAS No. 123(R). This EITF is applied prospectively and is effective for fiscal years beginning after December 15, 2007, and interim periods within those years. EITF 06-11 requires the disclosure of any change in accounting policy for income tax benefits of dividends or dividend equivalents on share-based payment awards as a result of adoption. We began applying the provisions of EITF 06-11 on January 1, 2008 with no material impact on our Consolidated Financial Statements.

In December 2007, the FASB issued SFAS No. 141(R) "Business Combinations" (SFAS No. 141(R)). SFAS No. 141 (R) applies to all business combinations and establishes guidance for recognizing and measuring identifiable assets acquired, liabilities assumed, noncontrolling interests in the acquiree and goodwill. Most of these items are recognized at their full fair value on the acquisition date, including acquisitions where the acquirer obtains control but less than 100 percent ownership in the acquiree. SFAS No. 141(R) also requires expensing of transaction costs as incurred and establishes disclosure requirements to enable the evaluation of the nature and financial effects of the business combination. SFAS No. 141(R) is effective for business combinations with an acquisition date in fiscal years beginning after December 15, 2008.

In December 2007, the FASB issued SFAS No. 160 "Noncontrolling Interests in Consolidated Financial Statements — an amendment of Accounting Research Bulletin No. 51" (SFAS No. 160). SFAS No. 160 establishes accounting and reporting standards for noncontrolling ownership interests in subsidiaries (previously referred to as minority interests). Noncontrolling ownership interests in consolidated subsidiaries will be presented in the consolidated balance sheet within stockholders' equity as a separate component from the parent's equity. Earnings attributable to the noncontrolling interests will be reported as a part of consolidated net income and not as a separate income or expense item. Earnings per share will continue to be based on earnings attributable to only the parent company and does not change upon adoption of SFAS No. 160. SFAS No. 160 provides guidance on accounting for changes in the parent's ownership interest in a subsidiary, including transactions where control is retained and where control is relinquished. SFAS No. 160 also requires additional disclosure of information related to noncontrolling interests. SFAS No. 160 is effective for fiscal years beginning after December 15, 2008, and early adoption is prohibited. The Statement will be applied prospectively to transactions involving noncontrolling interests, including noncontrolling interests that arose prior to the effective date, as of the beginning of the fiscal year it is initially adopted. However, the presentation of noncontrolling interests within stockholders' equity and the inclusion of earnings attributable to the noncontrolling interests in consolidated net income requires retrospective application to all periods presented. We will assess the impact on our Consolidated Financial Statements.

Note 2. Discontinued Operations

The businesses discussed below represent components that have been sold or approved for sale by our Board of Directors and are classified as discontinued operations. Therefore, their results of operations (including any impairments, gains or losses) and financial position have been reflected in the consolidated financial statements and notes as discontinued operations.

In November, 2007, we completed the sale of substantially all of our power business to Bear Energy, LP, a unit of The Bear Stearns Companies, Inc., for approximately $496 million in cash, subject to the final purchase price adjustments. Included in the sale was our portfolio of power-related contracts, which consisted of tolling contracts, full requirement contracts, tolling resales, heat rate options, related hedges and other related assets.

Summarized Results of Discontinued Operations

The following table presents the summarized results of discontinued operations for the years ended December 31, 2007, 2006, and 2005.

	2007	2006	2005
		(Millions)	
Revenues	$2,436	$2,437	$2,802
Income (loss) from discontinued operations before income taxes	$ 392	$ (58)	$ (247)
(Impairments) and gain (loss) on sales	(162)	—	1
Benefit (provision) for income taxes	(87)	20	89
Income (loss) from discontinued operations	$ 143	$ (38)	$ (157)

Income (loss) from discontinued operations before income taxes for the year ended December 31, 2007, includes a gain of $429 million (reported in *revenues* of discontinued operations) associated with the reclassification of deferred net hedge gains from *accumulated other comprehensive income* to earnings in second-quarter 2007. This reclassification was based on the determination that the forecasted transactions related to the derivative cash flow hedges being sold to Bear Energy, LP, were probable of not occurring. This gain is partially offset by current year unrealized mark-to-market losses of approximately $23 million. *Income (loss) from discontinued operations before income taxes* for the year ended December 31, 2006, includes charges of $19 million for an adverse arbitration award related to our former chemical fertilizer business, $6 million for a loss contingency in connection with a former exploration business, and $15 million associated with an oil purchase contract related to our former Alaska refinery. In addition, we recorded income of $13 million related to the reduction of contingent obligations associated with our former distributive power business. *Income (loss) from discontinued operations before income taxes* includes the results of our former power business operations in each year.

(Impairments) and gain (loss) on sales for the year ended December 31, 2007, includes a pre-tax loss on the sale of substantially all of our power business of approximately $37 million. We have also recognized impairments of approximately $111 million related to the carrying value of certain derivative contracts for which we had previously elected the normal purchases and normal sales exception under SFAS No. 133, and, accordingly, were no longer recording at fair value, and approximately $14 million related to our natural gas-fired electric generating

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plant near Hazelton, Pennsylvania (Hazleton). These impairments were based on our comparison of the carrying value to the estimate of fair value less cost to sell.

Summarized Assets and Liabilities of Discontinued Operations

The following table presents the summarized assets and liabilities of discontinued operations as of December 31, 2007 and 2006.

The December 31, 2007, balances for *derivative assets* and *derivative liabilities* represent contracts remaining to be assigned to Bear Energy, LP, entirely offset by reciprocal positions with Bear Energy, LP. We expect to complete the assignment of all such contracts in 2008. The December 31, 2007, balance of *property, plant and equipment — net* includes Hazelton, which is under contract to be sold.

	December 31, 2007	December 31, 2006
	(Millions)	
Derivative assets	$ 114	$ 593
Accounts receivable — net	55	232
Other current assets	3	12
Total current assets	172	837
Property, plant and equipment — net	8	23
Derivative assets	—	541
Other noncurrent assets	5	1
Total noncurrent assets	13	565
Total assets	$ 185	$ 1,402
Reflected on balance sheet as:		
Current assets	$ 185	$ 837
Noncurrent assets	—	565
Total assets	$ 185	$ 1,402
Derivative liabilities	$ 114	$ 479
Other current liabilities	61	260
Total current liabilities	175	739
Derivative liabilities	—	124
Other noncurrent liabilities	—	23
Total noncurrent liabilities	—	147
Total liabilities	$ 175	$ 886
Reflected on balance sheet as:		
Current liabilities	$ 175	$ 739
Noncurrent liabilities	—	147
Total liabilities	$ 175	$ 886

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Note 3. Investing Activities

Investing Income

Investing income for the years ended December 31, 2007, 2006 and 2005, is as follows:

	2007	2006 (Millions)	2005
Equity earnings*	$137	$ 99	$ 66
Loss from investments*	—	—	(109)
Impairments of cost-based investments	(1)	(20)	(2)
Interest income and other	121	89	70
Total	$257	$168	$ 25

* Items also included in *segment profit*. (See Note 17.)

Loss from investments for the year ended December 31, 2005, includes:

- An $87 million impairment of our investment in Longhorn Partners Pipeline L.P. (Longhorn), which is included in our Other segment;
- A $23 million impairment of our investment in Aux Sable Liquid Products, L.P. (Aux Sable), which is included in our Midstream segment.

Impairments of cost-based investments for the year ended December 31, 2006, includes a $16 million impairment of a Venezuelan investment primarily due to a decline in reserve estimates. In 2006, our 10 percent direct working interest in an operating contract was converted to a 4 percent equity interest in a Venezuelan corporation which owns and operates oil and gas activities. Our 4 percent equity interest is reported as a cost method investment; previously, we accounted for our working interest using the proportionate consolidation method.

Interest income and other for the year ended December 31, 2007, includes $14 million of gains from sales of cost-based investments.

Investments

Investments at December 31, 2007 and 2006, are as follows:

	2007 (Millions)	2006
Equity method:		
Gulfstream Natural Gas System, L.L.C. — 50%	$439	$387
Discovery Producer Services, L.L.C. — 60%*	215	221
Petrolera Entre Lomas S.A. — 40.8%	65	59
ACCROVEN — 49.3%	62	57
Other	95	90
	876	814
Cost method	25	52
	$901	$866

* We own 60 percent indirectly through Williams Partners L.P., of which we own approximately 23.6 percent. We continue to account for this investment under the equity method due to the voting provisions of Discovery's limited liability company which provide the other member of Discovery significant participatory rights such that we do not control the investment.

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Differences between the carrying value of our equity investments and the underlying equity in the net assets of the investees is primarily related to impairments previously recognized.

Dividends and distributions, including those presented below, received from companies accounted for by the equity method were $118 million in 2007 and $116 million in 2006. These transactions reduced the carrying value of our investments. These dividends and distributions primarily included:

	2007	2006
	(Millions)	
Discovery Producer Services, L.L.C.	$ 36	$ 27
Gulfstream Natural Gas System L.L.C.	34	42
Aux Sable Liquid Products L.P.	22	13
Petrolera Entre Lomas S.A.	12	14

In addition in 2007, we contributed $38 million to Gulfstream Natural Gas System L.L.C. (Gulfstream).

Summarized Financial Position and Results of Operations of Equity Method Investments

Financial position at December 31:

	2007	2006
	(Millions)	
Current assets	$ 395	$ 296
Noncurrent assets	3,482	3,302
Current liabilities	232	198
Noncurrent liabilities	1,483	1,311

Results of operations for the years ended December 31:

	2007	2006	2005
		(Millions)	
Gross revenue	$1,183	$970	$1,338
Operating income	533	401	236
Net income (loss)	392	(15)	105

Summarized results of operations of equity method investments in 2006 reflect the impact of a loss incurred by Longhorn on the sale of its pipeline.

Guarantees on Behalf of Investees

We have guaranteed commercial letters of credit totaling $20 million on behalf of ACCROVEN. These expire in January 2009 and have no carrying value.

We have provided guarantees on behalf of certain entities in which we have an equity ownership interest. These generally guarantee operating performance measures and the maximum potential future exposure cannot be determined. There are no expiration dates associated with these guarantees. No amounts have been accrued at December 31, 2007 and 2006.

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Note 4. Asset Sales and Other Accruals

The following table presents significant gains or losses from asset sales and other accruals or adjustments reflected in *other (income) expense — net* within *segment costs and expenses.*

	Years Ended December 31,		
	2007	2006	2005
		(Millions)	
Exploration & Production			
Gains on sales of certain natural gas properties	$ —	$ —	$ (30)
Gas Pipeline			
Change in estimate related to a regulatory liability	(17)	—	—
Income associated with payments received for a terminated firm transportation agreement on Grays Harbor lateral. Associated with this gain is interest income of $2 million, which is included in *investing income*	(18)	—	—
Midstream			
Income from favorable litigation outcome	(12)	—	—
Loss on impairment of Carbonate Trend pipeline	10	—	—
Accrual for Gulf Liquids litigation contingency. Associated with this contingency is an interest expense accrual of $25 million, which is included in *interest accrued* (see Note 15)	—	73	—
Gas Marketing Services			
Accrual for litigation contingencies	20	—	82

Additional Items

Costs and operating expenses within our Gas Pipeline segment reported in 2005 includes:

- An adjustment to reduce costs by $12 million to correct the carrying value of certain liabilities recorded in prior periods;
- Adjustments of $37 million reflected as increases in costs and operating expenses related to $32 million of prior period accounting and valuation corrections for certain inventory items and an accrual of $5 million for contingent refund obligations.

Selling, general and administrative expenses within our Gas Pipeline segment in 2005 includes:

- An adjustment to reduce costs by $6 million to correct the carrying value of certain liabilities recorded in prior periods;
- A $17 million reduction in pension expense for the cumulative impact of a correction of an error attributable to 2003 and 2004. (See Note 7.)

Note 5. Provision for Income Taxes

The *provision for income taxes* from continuing operations includes:

	2007	2006	2005
		(Millions)	
Current:			
Federal	$ 29	$ (9)	$225
State	9	3	3
Foreign	46	43	31
	84	37	259
Deferred:			
Federal	422	146	23
State	(4)	4	27
Foreign	22	24	(8)
	440	174	42
Total provision	$524	$211	$301

Reconciliations from the *provision for income taxes* from continuing operations at the federal statutory rate to the realized *provision for income taxes* are as follows:

	2007	2006	2005
		(Millions)	
Provision at statutory rate	$480	$195	$271
Increases (decreases) in taxes resulting from:			
State income taxes (net of federal benefit)	4	7	29
Foreign operations — net	18	23	2
Utilization/valuation/expiration of charitable contributions	(6)	(9)	8
Federal income tax litigation	—	(40)	4
Non-deductible convertible debenture expenses	—	10	—
Adjustment of excess deferred taxes	2	7	(20)
Non-deductible penalties	—	—	18
Other — net	26	18	(11)
Provision for income taxes	$524	$211	$301

Utilization of foreign operating loss carryovers reduced the provision for income taxes by $5 million, $3 million and $13 million in 2007, 2006 and 2005, respectively.

Income from continuing operations before income taxes and cumulative effect of change in accounting principle includes $169 million, $144 million, and $72 million of international income in 2007, 2006, and 2005, respectively.

We provide for income taxes using the asset and liability method as required by SFAS No. 109, "Accounting for Income Taxes." As a result of additional analysis of our tax basis and book basis assets and liabilities, we recorded a tax provision of $2 million and $7 million for 2007 and 2006, respectively, and a tax benefit of $20 million in 2005, to adjust the overall deferred income tax liabilities on the Consolidated Balance Sheet.

During the course of audits of our business by domestic and foreign tax authorities, we frequently face challenges regarding the amount of taxes due. These challenges include questions regarding the timing and amount

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

of deductions and the allocation of income among various tax jurisdictions. In evaluating the liability associated with our various tax filing positions, we apply the two-step process of recognition and measurement as required by FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109" (FIN 48). In association with this liability, we record an estimate of related interest and tax exposure as a component of our tax provision. The impact of this accrual is included within *other — net* in our reconciliation of the tax provision to the federal statutory rate.

Significant components of *deferred tax liabilities* and *deferred tax assets* as of December 31, 2007, and 2006, are as follows:

	2007	2006
	(Millions)	
Deferred tax liabilities:		
Property, plant and equipment	$3,192	$2,899
Derivatives — net	—	223
Investments	176	210
Other	89	101
Total deferred tax liabilities	3,457	3,433
Deferred tax assets:		
Minimum tax credits	8	146
Accrued liabilities	433	510
Derivatives — net	173	—
Federal carryovers	—	183
Foreign carryovers	50	36
Other	53	51
Total deferred tax assets	717	926
Less valuation allowance	57	36
Net deferred tax assets	660	890
Overall net deferred tax liabilities	$2,797	$2,543

The *valuation allowance* at December 31, 2007 and December 31, 2006, serves to reduce the recognized tax benefit associated with foreign carryovers to an amount that will, more likely than not, be realized. We do not expect to be able to utilize our $57 million foreign deferred tax assets primarily related to carryovers.

Undistributed earnings of certain consolidated foreign subsidiaries at December 31, 2007, totaled approximately $262 million. No provision for deferred U.S. income taxes has been made for these subsidiaries because we intend to permanently reinvest such earnings in foreign operations.

Cash payments for income taxes (net of refunds) were $384 million, $79 million, and $230 million in 2007, 2006, and 2005, respectively. Cash tax payments include settlements with taxing authorities associated with prior period audits of $94 million, $42 million, and $204 million in 2007, 2006 and 2005, respectively.

Effective January 1, 2007, we adopted FIN 48 and, as required by the Interpretation, recognized the net impact of the cumulative effect of adoption as a $17 million increase to *accumulated deficit*. The Interpretation prescribes guidance for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. To recognize a tax position, the enterprise determines whether it is more likely than not that the tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. A tax position that meets the more likely than not recognition threshold is measured to determine the amount of benefit to recognize in the financial statements. The tax position is measured as the largest amount of benefit, determined on a cumulative probability basis, that is greater than 50 percent likely of being realized upon ultimate settlement.

As of December 31, 2007, we had approximately $76 million of unrecognized tax benefits. If recognized, approximately $64 million, net of federal tax expense, would be recorded as a reduction of income tax expense. A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

	(Millions)
Balance at January 1, 2007	$ 93
Additions based on tax positions related to the current year	—
Additions for tax positions for prior years	5
Reductions for tax positions of prior years	(19)
Settlement with taxing authorities	(3)
Lapse of applicable statute of limitations	—
Balance at December 31, 2007	$ 76

We recognize related interest and penalties as a component of income tax expense. During 2007, approximately $60 million of interest and penalties were included in the provision for income taxes. As of December 31, 2007, approximately $86 million of interest and penalties primarily relating to uncertain tax positions have been accrued.

As of December 31, 2007, the Internal Revenue Service (IRS) examination of our consolidated U.S. income tax return for 2002 through 2005 was in process. IRS examinations for 1996 through 2001 have been completed but the years remain open while certain issues are under review with the Appeals Division of the IRS. The statute of limitations for most states expires one year after IRS audit settlement.

Generally, tax returns for our Venezuela and Canadian entities are open to audit from 2003 through 2007. Tax returns for our Argentine entities are open to audit from 2001 through 2007. Certain Canadian entities are currently under examination.

During the next twelve months, we do not expect settlement of any unrecognized tax benefit associated with domestic or international matters under audit to have a material impact on our financial position.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Note 6. Earnings Per Common Share from Continuing Operations

Basic and diluted earnings per common share for the years ended December 31, 2007, 2006 and 2005, are:

	2007	2006	2005
	(Dollars in millions, except per-share amounts; shares in thousands)		
Income from continuing operations available to common stockholders for basic and diluted earnings per share(1)	$ 847	$ 347	$ 473
Basic weighted-average shares(2)	596,174	595,053	570,420
Effect of dilutive securities:			
Nonvested restricted stock units(3)	1,627	1,029	2,890
Stock options	4,743	4,440	4,989
Convertible debentures	7,322	8,105	27,548
Diluted weighted-average shares	609,866	608,627	605,847
Earnings per common share from continuing operations:			
Basic	$ 1.42	$ .58	$ .82
Diluted	$ 1.40	$ .57	$ .79

(1) The years ended December 31, 2007, 2006 and 2005, include $3 million, $3 million and $10 million of interest expense, net of tax, associated with our convertible debentures. (See Note 12.) These amounts have been added back to *income from continuing operations available to common stockholders* to calculate diluted earnings per common share.

(2) During January 2006, we issued 20 million shares of common stock related to a conversion offer for our 5.5 percent convertible debentures. In February 2005, we issued 11 million common shares associated with our FELINE PACS units.

(3) The nonvested restricted stock units outstanding at December 31, 2007, will vest over the period from January 2008 to January 2012.

The table below includes information related to stock options that were outstanding at the end of each respective year but have been excluded from the computation of weighted-average stock options due to the option exercise price exceeding the fourth quarter weighted-average market price of our common shares.

	2007	2006	2005
Options excluded (millions)	.8	3.6	4.7
Weighted-average exercise prices of options excluded	$40.07	$36.14	$35.22
Exercise price ranges of options excluded	$36.66 - $42.29	$26.79 - $42.29	$22.68 - $42.29
Fourth quarter weighted-average market price	$35.14	$25.77	$22.41

Note 7. Employee Benefit Plans

We have noncontributory defined benefit pension plans in which all eligible employees participate. Currently, eligible employees earn benefits primarily based on a cash balance formula. Various other formulas, as defined in the plan documents, are utilized to calculate the retirement benefits for plan participants not covered by the cash balance formula. At the time of retirement, participants may receive annuity payments, a lump sum payment or a combination of lump sum and annuity payments. In addition to our pension plans, we currently provide subsidized

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

medical and life insurance benefits (other postretirement benefits) to certain eligible participants. Generally, employees hired after December 31, 1991, are not eligible for the subsidized medical benefits, except for participants that were employees of Transco Energy Company on December 31, 1995, and other miscellaneous defined participant groups. Certain of these other postretirement benefit plans, particularly the subsidized medical benefit plans, provide for retiree contributions and contain other cost-sharing features such as deductibles, co-payments, and co-insurance. The accounting for these plans anticipates future cost-sharing that is consistent with our expressed intent to increase the retiree contribution level generally in line with health care cost increases.

Benefit Obligations

The following table presents the changes in benefit obligations and plan assets for pension benefits and other postretirement benefits for the years indicated. The annual measurement date for our plans is December 31. The sale of our power business did not have a significant impact on our employee benefit plans. (See Note 2.)

	Pension Benefits		Other Postretirement Benefits	
	2007	2006	2007	2006
	(Millions)			
Change in benefit obligation:				
Benefit obligation at beginning of year	$ 931	$ 897	$312	$ 375
Service cost	23	22	3	3
Interest cost	54	51	17	17
Plan participants' contributions	—	—	5	5
Benefits paid	(64)	(52)	(23)	(24)
Actuarial (gain) loss	(48)	13	(30)	(64)
Benefit obligation at end of year	896	931	284	312
Change in plan assets:				
Fair value of plan assets at beginning of year	1,005	888	180	164
Actual return on plan assets	92	126	15	21
Employer contributions	41	43	15	14
Plan participants' contributions	—	—	5	5
Benefits paid	(64)	(52)	(23)	(24)
Fair value of plan assets at end of year	1,074	1,005	192	180
Funded status — overfunded (underfunded)	$ 178	$ 74	$ (92)	$(132)
Accumulated benefit obligation	$ 838	$ 872		

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The net underfunded/overfunded status of our pension plans and other postretirement benefit plans presented in the previous table are recognized in the Consolidated Balance Sheet within the following accounts:

	December 31,	
	2007	2006
	(Millions)	
Overfunded pension plans:		
Noncurrent assets	$203	$114
Underfunded pension plans:		
Current liabilities	1	1
Noncurrent liabilities	24	39
Underfunded other postretirement benefit plans:		
Current liabilities	9	9
Noncurrent liabilities	83	123

The plan assets within our other postretirement benefit plans are intended to be used for the payment of benefits for certain groups of participants. The *current liabilities* for the other postretirement benefit plans represent the actuarial present value of benefits included in the benefit obligation payable in the subsequent year for the groups of participants whose benefits are not expected to be paid from plan assets.

The 2007 *actuarial gain* of $48 million for our pension plans included in the table of changes in benefit obligation is due primarily to the impact of changes in the discount rate assumptions utilized to calculate the benefit obligation. The 2006 *actuarial loss* of $13 million for our pension plans included in the table of changes in benefit obligation is due primarily to the impact of actual results differing from assumed results such as compensation and participant deaths, offset by the net impact of changes in assumptions utilized to calculate the benefit obligation including the discount rate, mortality and expected form of benefit payments. The 2007 *actuarial gain* of $30 million for our other postretirement benefit plans included in the table of changes in benefit obligation is due primarily to the impact of the increase in the discount rate used to calculate the benefit obligation and a decrease in the number of eligible participants in the plan. The 2006 *actuarial gain* of $64 million for our other postretirement benefit plans included in the table of changes in benefit obligation is due primarily to the impact of changes in assumptions utilized to calculate the benefit obligation including claims costs, health care cost trend rates and the discount rate, as well as actual results differing from assumed results such as participant deaths and terminations prior to retirement.

The current accounting rules for the determination of *net periodic benefit expense* allow for the delayed recognition of gains and losses caused by differences between actual and assumed outcomes for items such as estimated return on plan assets, or caused by changes in assumptions for items such as discount rates or estimated future compensation levels. The *net actuarial gains (losses)* presented in the following table and recorded in *accumulated other comprehensive loss* and *net regulatory liabilities* represents the cumulative net deferred gains (losses) from these types of differences or changes which have not yet been recognized in the Consolidated Statement of Income. A portion of the *net actuarial gains (losses)* are amortized over the participants' average

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

remaining future years of service, which is approximately 12 years for both our pension plans and our other postretirement benefit plans.

Accumulated other comprehensive loss at December 31 includes the following:

	Pension Benefits		Other Postretirement Benefits	
	2007	2006	2007	2006
	(Millions)			
Amounts not yet recognized in net periodic benefit expense:				
Prior service cost	$ (6)	$ (6)	$ (5)	$ (7)
Net actuarial gains (losses)	(156)	(242)	7	(8)

At December 31, 2007, *net regulatory liabilities* includes prior service credits of $3 million and net actuarial gains of $26 million for our other postretirement benefit plans associated with our FERC-regulated gas pipelines. These amounts have not yet been recognized in *net periodic benefit expense.* At December 31, 2006, prior service credits of $5 million and net actuarial gains of $8 million were included in *net regulatory liabilities*.

We have multiple pension plans that are aggregated as prescribed for reporting purposes including both overfunded and underfunded pension plans.

Information for pension plans with a projected benefit obligation in excess of plan assets:

	December 31,	
	2007	2006
	(Millions)	
Projected benefit obligation	$ 25	$ 480
Fair value of plan assets	—	440

At December 31, 2007, the pension plans with a projected benefit obligation in excess of plan assets includes only our unfunded nonqualified pension plans. At December 31, 2006, the pension plans with a projected benefit obligation in excess of plan assets included one of our funded tax-qualified pension plans and our unfunded nonqualified pension plans.

Information for pension plans with an accumulated benefit obligation in excess of plan assets:

	December 31,	
	2007	2006
	(Millions)	
Accumulated benefit obligation	$ 22	$ 19
Fair value of plan assets	—	—

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Net Periodic Benefit Expense (Income) and Items Recognized in Other Comprehensive Income (Loss)

Net periodic benefit expense (income) and other changes in plan assets and benefit obligations recognized in *other comprehensive income (loss)* for the years ended December 31, 2007, 2006, and 2005, consist of the following:

	Pension Benefits			Other Postretirement Benefits		
	2007	2006	2005	2007	2006	2005
	(Millions)					
Components of net periodic benefit expense (income):						
Service cost	$ 23	$ 22	$ 21	$ 3	$ 3	$ 3
Interest cost	54	51	47	17	17	20
Expected return on plan assets	(73)	(67)	(71)	(12)	(11)	(11)
Amortization of prior service credit	—	(1)	—	—	—	(4)
Amortization of net actuarial (gain) loss	19	21	(5)	—	—	3
Regulatory asset amortization	1	—	1	5	7	7
Settlement/curtailment expense	—	—	3	—	—	—
Net periodic benefit expense (income)	$ 24	$ 26	$ (4)	$ 13	$ 16	$ 18
Other changes in plan assets and benefit obligations recognized in *other comprehensive income (loss):*						
Net actuarial gain	$ (68)			$ (15)		
Amortization of net actuarial losses	(19)			—		
Amortization of prior service costs	—			(2)		
Other changes in plan assets and benefit obligations recognized in *other comprehensive income (loss)*	(87)			(17)		
Total recognized in *net periodic benefit expense* and *other comprehensive income (loss)*	$ (63)			$ (4)		

Other changes in plan assets and benefit obligations for our other postretirement benefit plans associated with our FERC-regulated gas pipelines are recognized in *net regulatory liabilities* at December 31, 2007, and include *net actuarial gains* of $18 million and *amortization of prior service credits* of $2 million.

Net actuarial losses of $8 million and prior service costs of $1 million related to our pension plans that are included in *accumulated other comprehensive loss* at December 31, 2007, are expected to be amortized in *net periodic benefit expense* in 2008. Prior service costs of $1 million related to our other postretirement benefit plans that are included in *accumulated other comprehensive loss* at December 31, 2007, are expected to be amortized in *net periodic benefit expense* in 2008. No net actuarial losses related to our other postretirement benefit plans that are included in *accumulated other comprehensive loss* at December 31, 2007, are expected to be amortized in *net periodic benefit expense* in 2008.

The prior service credit related to our other postretirement benefit plans that is included in *net regulatory liabilities* at December 31, 2007, and expected to be recognized in *net periodic benefit expense (income)* in 2008 is $1 million. No net actuarial gains related to our other postretirement benefit plans and included in *net regulatory liabilities* are expected to be recognized in *net periodic benefit expense* in 2008.

Net periodic benefit expense (income) for our pension plans for 2005 includes a $17 million reduction to expense to record the cumulative impact of a correction of an error determined to have occurred in 2003 and 2004.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The error was associated with the actuarial computation of annual *net periodic benefit expense (income)* which resulted from the identification of errors in certain Transco participant data involving annuity contract information utilized for 2003 and 2004. The adjustment is reflected as $16 million within *amortization of net actuarial (gain) loss* and $1 million within *regulatory asset amortization*.

The differences in the amount of actuarially determined *net periodic benefit expense* for our other postretirement benefit plans and the other postretirement benefit costs recovered in rates for our FERC-regulated gas pipelines are deferred as a regulatory asset or liability. At December 31, 2007, we have regulatory liabilities of $10 million for Transco and $18 million for Northwest Pipeline related to these deferrals. At December 31, 2006, we had a regulatory asset of $9 million for Transco and a regulatory liability of $13 million at Northwest Pipeline related to these deferrals. These amounts will be reflected in future rates based on Transco and Northwest Pipeline's rate structures.

Key Assumptions

The weighted-average assumptions utilized to determine benefit obligations as of December 31, 2007, and 2006, are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2007	2006	2007	2006
Discount rate	6.41%	5.80%	6.40%	5.80%
Rate of compensation increase	5.00	5.00	N/A	N/A

The weighted-average assumptions utilized to determine *net periodic benefit expense* for the years ended December 31, 2007, 2006, and 2005, are as follows:

	Pension Benefits			Other Postretirement Benefits		
	2007	2006	2005	2007	2006	2005
Discount rate	5.80%	5.65%	5.86%	5.80%	5.60%	5.63%
Expected long-term rate of return on plan assets	7.75	7.75	8.50	6.97	6.95	7.45
Rate of compensation increase	5.00	5.00	5.00	N/A	N/A	N/A

The discount rates for our pension and other postretirement benefit plans were determined separately based on an approach specific to our plans and their respective expected benefit cash flows. The plans were analyzed and the year-end discount rates were determined based on a yield curve comprised of high-quality corporate bonds published by a large securities firm.

The expected long-term rates of return on plan assets were determined by combining a review of the historical returns realized within the portfolio, the investment strategy included in the plans' Investment Policy Statement, and capital market projections for the asset classifications in which the portfolio is invested and the target weightings of each asset classification.

The mortality assumptions used to determine the obligations for our pension and other postretirement benefit plans are related to the experience of the plans and the best estimate of expected plan mortality. The selected mortality tables are among the most recent tables available.

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The assumed health care cost trend rate for 2008 is 9.6 percent, and systematically decreases to 5.4 percent by 2015. The health care cost trend rate assumption has a significant effect on the amounts reported. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	Point increase	Point decrease
	(Millions)	
Effect on total of service and interest cost components	$ 3	$ (4)
Effect on other postretirement benefit obligation	55	(44)

Plan Assets

The investment policy for our pension and other postretirement benefit plans articulates an investment philosophy in accordance with ERISA which governs the investment of the assets in a diversified portfolio. The investment strategy for the assets of the pension plans and approximately one half of the assets of the other postretirement benefit plans include maximizing returns with reasonable and prudent levels of risk. The investment returns on the approximate one half of remaining assets of the other postretirement benefit plans is subject to federal income tax, therefore the investment strategy also includes investing in a tax efficient manner.

The following table presents the weighted-average asset allocations at December 31, 2007, and 2006 and target asset allocation at December 31, 2007, by asset category.

	Pension Benefits			Other Postretirement Benefits		
	2007	2006	Target	2007	2006	Target
Equity securities	84%	82%	84%	79%	77%	80%
Debt securities	12	12	16	12	12	20
Other	4	6	—	9	11	—
	100%	100%	100%	100%	100%	100%

Included in equity securities are investments in commingled funds that invest entirely in equity securities and comprise 40 percent at December 31, 2007, and 38 percent at December 31, 2006, of the pension plans' weighted-average assets, and 29 percent at December 31, 2007, and 27 percent at December 31, 2006, of the other postretirement benefit plans' weighted-average assets. Other assets are comprised primarily of cash and cash equivalents.

The assets are invested in accordance with the target allocations identified in the previous table. The investment policy provides for minimum and maximum ranges for the broad asset classes in the previous table. Additional target allocations are identified for specific classes of equity securities. The asset allocation ranges established by the investment policy are based upon a long-term investment perspective. The ranges are more heavily weighted toward equity securities since the liabilities of the pension and other postretirement benefit plans are long-term in nature and historically equity securities have significantly outperformed other asset classes over long periods of time.

Equity security investments are restricted to high-quality, readily marketable securities that are actively traded on the major U.S. and foreign national exchanges. Investment in Williams' securities or an entity in which Williams has a majority ownership is prohibited except where these securities may be owned in a commingled investment vehicle in which the pension plans' trust invests. No more than five percent of the total stock portfolio valued at market may be invested in the common stock of any one corporation. The following securities and transactions are not authorized: unregistered securities, commodities or commodity contracts, short sales or margin transactions or other leveraging strategies. Investment strategies using options or futures are not authorized.

Debt security investments are restricted to high-quality, marketable securities that include U.S. Treasury, federal agencies and U.S. Government guaranteed obligations, and investment grade corporate issues. The overall

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rating of the debt security assets is required to be at least "A", according to the Moody's or Standard & Poor's rating system. No more than five percent of the total portfolio at the time of purchase may be invested in the debt securities of any one issuer. U.S. Government guaranteed and agency securities are exempt from this provision.

During 2007, 11 active investment managers and one passive investment manager managed substantially all of the pension and other postretirement benefit plans' funds, each of whom had responsibility for managing a specific portion of these assets.

Plan Benefit Payments and Employer Contributions

The following are the expected benefits to be paid by the plan and the expected federal prescription drug subsidy to be received in the next ten years. These estimates are based on the same assumptions previously discussed and reflect future service as appropriate. The actuarial assumptions are based on long-term expectations and include, but are not limited to, assumptions as to average expected retirement age and form of benefit payment. Actual benefit payments could differ significantly from expected benefit payments if near-term participant behaviors differ significantly from the actuarial assumptions.

	Pension Benefits	Other Postretirement Benefits	Federal Prescription Drug Subsidy
		(Millions)	
2008	$ 46	$ 20	$ (2)
2009	40	21	(2)
2010	36	21	(2)
2011	37	22	(2)
2012	43	21	(2)
2013 - 2017	265	110	(15)

We expect to contribute approximately $41 million to our pension plans and approximately $15 million to our other postretirement benefit plans in 2008.

Defined Contribution Plans

We also maintain defined contribution plans for the benefit of substantially all of our employees. Generally, plan participants may contribute a portion of their compensation on a pre-tax and after-tax basis in accordance with the plan's guidelines. We match employees' contributions up to certain limits. Costs recognized for these plans were $22 million in 2007, $19 million in 2006, and $17 million in 2005. One of our defined contribution plans was amended as of July 1, 2005, to convert one of the funds within the plan to a nonleveraged employee stock ownership plan (ESOP). The 2005 compensation cost related to the ESOP of $1 million is included in the $17 million of contributions, previously mentioned above, and represents the contribution made in consideration for employee services rendered in 2005. It is measured by the amount of cash contributed to the ESOP. The shares held by the ESOP are treated as outstanding when computing earnings per share and the dividends on the shares held by the ESOP are recorded as a component of retained earnings. For 2006 and future years, there were and will be no contributions to this ESOP, other than dividend reinvestment, as contributions for purchase of our stock is now restricted within this defined contribution plan.

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Note 8. Inventories

Inventories at December 31, 2007, and 2006, are as follows:

	2007	2006
	(Millions)	
Natural gas liquids	$ 66	$ 78
Natural gas in underground storage	45	78
Materials, supplies and other	98	82
	$209	$238

Inventories determined using the LIFO cost method were less than 1 percent and 11 percent of *inventories* at December 31, 2007 and 2006, respectively. The remaining *inventories* were primarily determined using the average-cost method.

If *inventories* valued using the LIFO cost method at December 31, 2007 and 2006, were valued at current replacement cost, the amounts would increase by less than $1 million and $22 million, respectively.

Note 9. Property, Plant and Equipment

Property, plant and equipment — net at December 31, 2007, and 2006, is as follows:

	2007	2006
	(Millions)	
Cost:		
Exploration & Production	$ 7,660	$ 5,918
Gas Pipeline	9,525	9,127
Midstream Gas & Liquids(1)	5,285	4,590
Gas Marketing Services	63	69
Other	254	245
	22,787	19,949
Accumulated depreciation, depletion and amortization	(6,806)	(5,791)
	$15,981	$14,158

(1) Certain assets above are currently pledged as collateral to secure debt. (See Note 11.)

Depreciation, depletion and amortization expense for *property, plant and equipment — net* was $1.1 billion in 2007, $863 million in 2006, and $736 million in 2005.

Property, plant and equipment — net includes approximately $980 million at December 31, 2007, and $685 million at December 31, 2006, of construction in progress which is not yet subject to depreciation. In addition, property of Exploration & Production includes approximately $378 million at December 31, 2007, and $414 million at December 31, 2006, of capitalized costs related to properties with unproven reserves not yet subject to depletion.

Property, plant and equipment — net includes approximately $1.1 billion at December 31, 2007 and 2006 related to amounts in excess of the original cost of the regulated facilities within Gas Pipeline as a result of our prior acquisitions. This amount is being amortized over 40 years using the straight-line amortization method. Current FERC policy does not permit recovery through rates for amounts in excess of original cost of construction.

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THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Asset Retirement Obligations

The asset retirement obligation at December 31, 2007 and 2006 is $399 million and $333 million, respectively. The increases in the obligation in 2007 are due to revisions in our estimation of our asset retirement obligation in our Midstream segment, increased asset additions in our Exploration and Production segment and increased accretion in our Gas Pipeline segment. The increases in the obligation in 2006 were due primarily to obtaining additional information that revised our estimation of our asset retirement obligation for certain assets in our Exploration & Production, Gas Pipeline, and Midstream segments. Factors affected by the additional information included estimated settlement dates, estimated settlement costs, and inflation rates.

The accrued obligations relate to producing wells, underground storage caverns, offshore platforms, fractionation facilities, gas gathering well connections and pipelines, and gas transmission facilities. At the end of the useful life of each respective asset, we are legally obligated to plug both producing wells and storage caverns and remove any related surface equipment, remove surface equipment and restore land at fractionation facilities, to dismantle offshore platforms, to cap certain gathering pipelines at the wellhead connection and remove any related surface equipment, and to remove certain components of gas transmission facilities from the ground.

Note 10. Accounts Payable and Accrued Liabilities

Under our cash-management system, certain cash accounts reflected negative balances to the extent checks written have not been presented for payment. These negative balances represent obligations and have been reclassified to *accounts payable. Accounts payable* includes approximately $96 million of these negative balances at December 31, 2007, and $44 million at December 31, 2006.

Accrued liabilities at December 31, 2007, and 2006, are as follows:

	2007	2006
	(Millions)	
Interest	$ 208	$ 243
Employee costs	174	155
Taxes other than income taxes	169	152
Estimated rate refund liability	96	2
Accrual for Gulf Liquids litigation contingency	94**	95*
Income taxes	75	81
Guarantees and payment obligations related to WilTel	39	41
Customer margin deposits payable	10	129
Structured indemnity settlement	—	34
Other, including other loss contingencies	293	421
	$1,158	$1,353

* Includes $22 million of interest.

** Includes $25 million of interest.

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Note 11. Debt, Leases and Banking Arrangements

Long-Term Debt

Long-term debt at December 31, 2007 and 2006, is:

	Weighted-Average Interest Rate(1)	December 31, 2007(2)	December 31, 2006
		(Millions)	
Secured(3)			
6.62%-9.45%, payable through 2016	8.0%	$ 148	$ 172
Adjustable rate, payable through 2016	6.3%	64	74
Capital lease obligations	6.7%	10	2
Unsecured			
5.5%-10.25%, payable through 2033(4)	7.6%	7,103	7,691
Revolving credit loans	5.7%	250	—
Adjustable rate, payable through 2012	6.2%	325	75
Total long-term debt, including current portion		7,900	8,014
Long-term debt due within one year		(143)	(392)
Long-term debt		$ 7,757	$7,622

(1) At December 31, 2007.

(2) Certain of our debt agreements contain covenants that restrict or limit, among other things, our ability to create liens, sell assets, make certain distributions, repurchase equity and incur additional debt.

(3) Includes $212 million and $246 million at December 31, 2007 and 2006, respectively, collateralized by certain fixed assets of two of our Venezuelan subsidiaries with a net book value of $351 million and $380 million at December 31, 2007 and 2006, respectively.

(4) 2007 includes Transco's $100 million 6.25 percent notes, due on January 15, 2008, that were reclassified as long-term debt as a result of a subsequent refinancing under the $1.5 billion revolving credit facility.

Revolving credit and letter of credit facilities (credit facilities)

We have an unsecured, $1.5 billion revolving credit facility with a maturity date of May 1, 2012. Northwest Pipeline and Transco each have access to $400 million under the facility to the extent not otherwise utilized by us. Interest is calculated based on a choice of two methods: a fluctuating rate equal to the lender's base rate plus an applicable margin or a periodic fixed rate equal to LIBOR plus an applicable margin. We are required to pay a commitment fee (currently 0.125 percent) based on the unused portion of the facility. The margins and commitment fee are generally based on the specific borrower's senior unsecured long-term debt ratings. Significant financial covenants under the credit agreement include the following:

- Our ratio of debt to capitalization must be no greater than 65 percent. At December 31, 2007, we are in compliance with this covenant as our ratio of debt to capitalization, as calculated under this covenant, is approximately 51 percent.
- Ratio of debt to capitalization must be no greater than 55 percent for Northwest Pipeline and Transco. At December 31, 2007, we are in compliance with this covenant as our ratio of debt to capitalization, as calculated under this covenant, is approximately 36 percent for Northwest Pipeline and 31 percent for Transco.

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Our $500 million and $700 million facilities provide for both borrowings and issuing letters of credit but are expected to be used primarily for issuing letters of credit. These facilities mature in 2009 and 2010, respectively. We are required to pay the funding bank fixed fees at a weighted-average interest rate of 3.64 percent and 2.29 percent for the $500 million and $700 million facilities, respectively, on the total committed amount of the facilities. In addition, we pay interest on any borrowings at a fluctuating rate comprised of either a base rate or LIBOR.

The funding bank syndicated its associated credit risk through a private offering that allows for the resale of certain restricted securities to qualified institutional buyers. To facilitate the syndication of these facilities, the bank established trusts funded by the institutional investors. The assets of the trusts serve as collateral to reimburse the bank for our borrowings in the event that the facilities are delivered to the investors as described below. Thus, we have no asset securitization or collateral requirements under the facilities. Upon the occurrence of certain credit events, letters of credit under the agreement become cash collateralized creating a borrowing under the facilities. Concurrently, the funding bank can deliver the facilities to the institutional investors, whereby the investors replace the funding bank as lender under the facilities. Upon such occurrence, we will pay:

	$500 Million Facility		$700 Million Facility	
	$400 million	$100 million	$500 million	$200 million
Interest Rate	3.57 percent	LIBOR	4.35 percent	LIBOR
Facility Fixed Fee	3.19 percent		2.29 percent	

In December 2007, Williams Partners L.P. acquired certain of our membership interests in Wamsutter LLC, the limited liability company that owns the Wamsutter system, from us for $750 million. Williams Partners L.P completed the transaction after successfully closing a public equity offering of 9.25 million common units that yielded net proceeds of approximately $335 million. The partnership financed the remainder of the purchase price primarily through utilizing $250 million of term loan borrowings and issuing approximately $157 million of common units to us. The $250 million term loan is under Williams Partners L.P.'s new $450 million five-year senior unsecured credit facility that became effective simultaneous with the closing of the Wamsutter transaction. This $450 million credit facility is comprised initially of a $200 million revolving credit facility available for borrowings and letters of credit and a $250 million term loan. Under certain conditions, the revolving credit facility may be increased up to an additional $100 million. Interest on borrowings under this agreement will be payable at rates per annum equal to either (1) a fluctuating base rate equal to the lender's prime rate plus the applicable margin, or (2) a periodic fixed rate equal to LIBOR plus the applicable margin. At December 31, 2007, there were no amounts outstanding under the $200 million revolving credit facility.

In December 2007, Northwest Pipeline borrowed $250 million under the $1.5 billion revolving credit facility to retire its $250 million 6.625 percent notes that matured on December 1, 2007.

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Letters of credit issued under our credit facilities are:

	Letters of Credit at December 31, 2007 (Millions)
$500 million unsecured credit facilities	$ 243
$700 million unsecured credit facilities	$ 99
$1.5 billion unsecured credit facility	$ 28

Exploration & Production's credit agreement

In February 2007, Exploration & Production entered into a five-year unsecured credit agreement with certain banks in order to reduce margin requirements related to our hedging activities as well as lower transaction fees. Under the credit agreement, Exploration & Production is not required to post collateral as long as the value of its domestic natural gas reserves, as determined under the provisions of the agreement, exceeds by a specified amount certain of its obligations including any outstanding debt and the aggregate out-of-the-money positions on hedges entered into under the credit agreement. Exploration & Production is subject to additional covenants under the credit agreement including restrictions on hedge limits, the creation of liens, the incurrence of debt, the sale of assets and properties, and making certain payments, such as dividends, under certain circumstances.

Issuances and retirements

On May 28, 2003, we issued $300 million of 5.5 percent junior subordinated convertible debentures due 2033. These notes, which are callable after seven years, are convertible at the option of the holder into our common stock at a conversion price of approximately $10.89 per share. In November 2005, we initiated an offer to convert these debentures to shares of our common stock. In January 2006, we converted approximately $220 million of the debentures. (See Note 12.)

In June 2006, Williams Partners L.P. acquired 25.1 percent of our interest in Williams Four Corners LLC for $360 million. The acquisition was completed after Williams Partners L.P. successfully closed a $150 million private debt offering of 7.5 percent senior unsecured notes due 2011 and a public equity offering of approximately $225 million in net proceeds.

In December 2006, Williams Partners L.P. acquired the remaining 74.9 percent interest in Williams Four Corners LLC for $1.223 billion. The acquisition was completed after Williams Partners L.P. successfully closed a $600 million private debt offering of 7.25 percent senior unsecured notes due 2017, a private equity offering of approximately $350 million of common and Class B units, and a public equity offering of approximately $294 million in net proceeds.

In connection with the issuance of the $150 million 7.5 percent notes and the $600 million 7.25 percent notes discussed above, Williams Partners L.P. entered into registration rights agreements with the initial purchasers of the senior unsecured notes. In these agreements they agreed to conduct a registered exchange offer for the senior unsecured notes or cause to become effective a shelf registration statement providing for resale of the senior unsecured notes. Williams Partners L.P. initiated exchange offers for both series on April 10, 2007. The exchange offers were completed and closed on May 11, 2007.

In connection with the issuance of approximately $350 million of common and Class B units in a private equity offering discussed above, Williams Partners L.P. entered into a registration rights agreement with the initial purchasers whereby Williams Partners L.P. agreed to file a shelf registration statement providing for the resale of the common units purchased. Additionally, the registration rights agreement provides for the registration of common units that would be issued upon conversion of the Class B units. Williams Partners L.P. filed the shelf registration statement on January 12, 2007, and it became effective on March 13, 2007. On May 21, 2007, Williams Partners L.P.'s outstanding Class B units were converted into common units on a one-for-one basis. If the shelf registration

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statement is unavailable for a period that exceeds an aggregate of 30 days in any 90-day period or 105 days in any 365-day period, the purchasers are entitled to receive liquidated damages. Liquidated damages are calculated as 0.25 percent of the Liquidated Damages Multiplier per 30-day period for the first 60 days following the 90th day, increasing by an additional 0.25 percent of the Liquidated Damages Multiplier per 30-day period for each subsequent 60 days, up to a maximum of 1.00 percent of the Liquidated Damages Multiplier per 30-day period, provided the aggregate amount of liquidated damages payable to any purchaser is capped at 10 percent of the Liquidated Damages Multiplier. The Liquidated Damages Multiplier is (i) the product of $36.59 times the number of common units purchased plus (ii) the product of $35.81 times the number of Class B units purchased. Due to amendments made to Rule 144 of the Securities Act in February 2008, related to securities acquired by non-affiliates from an issuer subject to public reporting requirements, Williams Partners L.P. no longer has an obligation to keep their shelf registration statement effective and would have no liability for a failure to do so.

The debt and equity issued to third parties by Williams Partners L.P. is reported as a component of our consolidated debt balance and minority interest balance, respectively.

On April 4, 2007, Northwest Pipeline retired $175 million of 8.125 percent senior unsecured notes due 2010. Northwest Pipeline paid premiums of approximately $7 million in conjunction with the early debt retirement. These premiums are considered recoverable through rates and are therefore deferred as a component of *other assets and deferred charges* on our consolidated balance sheet, amortizing over the life of the original debt.

On April 5, 2007, Northwest Pipeline issued $185 million aggregate principal amount of 5.95 percent senior unsecured notes due 2017 to certain institutional investors in a private debt placement. In August 2007, Northwest Pipeline completed an exchange of these notes for substantially identical new notes that are registered under the Securities Act of 1933, as amended.

Under the terms of the Northwest Pipeline $185 million 5.95 percent senior unsecured notes mentioned above, Northwest Pipeline was obligated to file a registration statement for an offer to exchange the notes for a new issue of substantially identical notes registered under the Securities Act of 1933, as amended, within 180 days from closing and use its commercially reasonable efforts to cause the registration statement to be declared effective within 270 days after closing. Northwest Pipeline initiated an exchange offer on July 26, 2007, which expired on August 23, 2007. Northwest Pipeline received full participation in the exchange offer.

During December 2007, we repurchased $22 million of our 8.125 percent senior unsecured notes due March 2012 and $213 million of our 7.125 percent senior unsecured notes due September 2011. In conjunction with these early retirements, we paid premiums of approximately $19 million. These premiums, as well as related fees and expenses are recorded as *early debt retirement costs* in the Consolidated Statement of Income.

Aggregate minimum maturities of *long-term debt* (excluding capital leases and unamortized discount and premium) for each of the next five years are as follows:

	(Millions)
2008	$ 138
2009	53
2010	39
2011	955
2012	1,576

Cash payments for interest (net of amounts capitalized) were as follows: 2007 — $634 million; 2006 — $611 million; and 2005 — $625 million.

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Leases-Lessee

Future minimum annual rentals under noncancelable operating leases as of December 31, 2007, are payable as follows:

	(Millions)
2008	$ 83
2009	63
2010	30
2011	15
2012	13
Thereafter	19
Total	$ 223

Total rent expense was $68 million in 2007, $68 million in 2006, and $65 million in 2005. Rent expense reported as discontinued operations, primarily related to a tolling agreement, was $148 million in 2007, $175 million in 2006, and $161 million in 2005. Rent expense in discontinued operations was offset by approximately $276 million in 2007, $264 million in 2006, and $172 million in 2005 resulting from sales and other transactions made possible by the tolling agreement. This tolling agreement was included in the sale of our power business to Bear Energy, LP. (See Note 2.)

Note 12. Stockholders' Equity

In July 2007, our Board of Directors authorized the repurchase of up to $1 billion of our common stock. We intend to purchase shares of our stock from time to time in open-market transactions or through privately negotiated or structured transactions at our discretion, subject to market conditions and other factors. This stock-repurchase program does not have an expiration date. During 2007, we purchased approximately 16 million shares for $526 million (including transaction costs) under the program at an average cost of $33.08 per share. This stock repurchase is recorded in *treasury stock* on the Consolidated Balance Sheet.

In November 2005, we initiated an offer to convert our 5.5 percent junior subordinated convertible debentures into our common stock. In January 2006, we converted approximately $220 million of the debentures in exchange for 20 million shares of common stock, a $26 million cash premium, and $2 million of accrued interest.

We maintain a Stockholder Rights Plan, as amended and restated on September 21, 2004, and further amended May 18, 2007, and October 12, 2007, under which each outstanding share of our common stock has a right (as defined in the plan) attached. Under certain conditions, each right may be exercised to purchase, at an exercise price of $50 (subject to adjustment), one two-hundredth of a share of Series A Junior Participating Preferred Stock. The rights may be exercised only if an Acquiring Person acquires (or obtains the right to acquire) 15 percent or more of our common stock or commences an offer for 15 percent or more of our common stock. The plan contains a mechanism to divest of shares of common stock if such stock in excess of 14.9 percent was acquired inadvertently or without knowledge of the terms of the rights. The rights, which until exercised do not have voting rights, expire in 2014 and may be redeemed at a price of $.01 per right prior to their expiration, or within a specified period of time after the occurrence of certain events. In the event a person becomes the owner of more than 15 percent of our common stock, each holder of a right (except an Acquiring Person) shall have the right to receive, upon exercise, our common stock having a value equal to two times the exercise price of the right. In the event we are engaged in a merger, business combination, or 50 percent or more of our assets, cash flow or earnings power is sold or transferred, each holder of a right (except an Acquiring Person) shall have the right to receive, upon exercise, common stock of the acquiring company having a value equal to two times the exercise price of the right.

Note 13. Stock-Based Compensation

Plan Information

Effective May 17, 2007, our stockholders approved a new plan that provides common-stock-based awards to both employees and nonmanagement directors. The new plan generally contains terms and provisions consistent with the previous plans. The new plan reserves 19 million shares for issuance. Awards outstanding in all prior plans remain in those plans with their respective terms and provisions. No new grants will be made from the prior plans. The new plan permits the granting of various types of awards including, but not limited to, restricted stock units and stock options. Restricted stock units are generally valued at market value on the grant date of the award and generally vest over three years. The purchase price per share for stock options generally may not be less than the market price of the underlying stock on the date of grant. Stock options generally become exercisable over a three-year period from the date of the grant and can be subject to accelerated vesting if certain future stock prices or if specific financial performance targets are achieved. Stock options generally expire 10 years after grant. At December 31, 2007, 37 million shares of our common stock were reserved for issuance pursuant to existing and future stock awards, of which 19 million shares were available for future grants.

Additionally, on May 17, 2007, our stockholders approved an Employee Stock Purchase Plan (ESPP) which authorizes up to 2 million shares of our common stock to be available for sale under the plan. The ESPP enables eligible participants to purchase our common stock through payroll deductions not exceeding an annual amount of $15,000 per participant. The ESPP provides for offering periods during which shares may be purchased and continues until the earliest of: (1) the Board of Directors terminates the ESPP, (2) the sale of all shares available under the ESPP, or (3) the tenth anniversary of the date the Plan was approved by the stockholders. The first offering under the ESPP commenced on October 1, 2007 and ended on December 31, 2007. Subsequent offering periods will be from January through June and from July through December. Generally, all employees are eligible to participate in the ESPP, with the exception of executives and international employees. The number of shares eligible for an employee to purchase during each offering period is limited to 750 shares. The purchase price of the stock is 85 percent of the lower closing price of either the first or the last day of the offering period. The ESPP requires a one-year holding period before the stock can be sold. Approximately 2 million shares were available for purchase under the ESPP at December 31, 2007.

Stock Options

Stock options are valued at the date of award, which does not precede the approval date, and compensation cost is recognized on a straight-line basis, net of estimated forfeitures, over the requisite service period. Stock options generally become exercisable over a three-year period from the date of grant and generally expire ten years after the grant.

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The following summary reflects stock option activity and related information for the year ending December 31, 2007.

Stock Options	Options	Weighted-Average Exercise Price	Aggregate Intrinsic Value
	(Millions)		(Millions)
Outstanding at December 31, 2006	17.7	$ 16.96	
Granted	1.2	$ 28.32	
Exercised	(4.1)	$ 13.78	$ 74
Cancelled	(1.6)	$ 36.04	
Outstanding at December 31, 2007	13.2	$ 16.62	$ 256
Exercisable at December 31, 2007	10.4	$ 14.79	$ 222

The total intrinsic value of options exercised during the years ended December 31, 2007, 2006, and 2005 was $74 million, $36 million, and $42 million, respectively.

The following summary provides additional information about stock options that are outstanding and exercisable at December 31, 2007.

	Stock Options Outstanding			Stock Options Exercisable		
Range of Exercise Prices	Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Life	Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Life
	(Millions)		(Years)	(Millions)		(Years)
$2.27 to $12.92	6.0	$ 6.98	4.9	6.0	$ 6.98	4.9
$12.93 to $23.72	4.4	$ 19.41	6.9	2.8	$ 18.87	6.5
$23.73 to $34.52	1.4	$ 28.25	7.7	.3	$ 28.00	2.2
$34.53 to $45.32	1.4	$ 37.68	1.9	1.3	$ 37.68	1.9
Total	13.2	$ 16.62	5.6	10.4	$ 14.79	4.9

The estimated fair value at date of grant of options for our common stock granted in 2007, 2006, and 2005, using the Black-Scholes option pricing model, is as follows:

	2007	2006	2005
Weighted-average grant date fair value of options for our common stock granted during the year	$9.09	$8.36	$6.70
Weighted-average assumptions:			
Dividend yield	1.5%	1.4%	1.6%
Volatility	28.7%	36.3%	33.3%
Risk-free interest rate	4.6%	4.7%	4.1%
Expected life (years)	6.3	6.5	6.5

The expected dividend yield is based on the average annual dividend yield as of the grant date. Expected volatility is based on the historical volatility of our stock and the implied volatility of our stock based on traded options. In calculating historical volatility, returns during calendar year 2002 were excluded as the extreme volatility during that time is not reasonably expected to be repeated in the future. The risk-free interest rate is based on the U.S. Treasury Constant Maturity rates as of the grant date. The expected life of the option is based on historical exercise behavior and expected future experience.

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Cash received from stock option exercises was $56 million, $34 million and $39 million during 2007, 2006 and 2005, respectively. The tax benefit realized from stock options exercised during 2007 was $27 million and $14 million for both 2006 and 2005.

Nonvested Restricted Stock Units

Restricted stock units are generally valued at market value on the grant date and generally vest over three years. Restricted stock unit expense, net of estimated forfeitures, is generally recognized over the vesting period on a straight-line basis.

The following summary reflects nonvested restricted stock unit activity and related information for the year ended December 31, 2007.

Restricted Stock Units	Shares (Millions)	Weighted-Average Fair Value*
Nonvested at December 31, 2006	3.7	$ 20.57
Granted	1.8	$ 30.79
Forfeited	(0.1)	$ 23.53
Vested	(1.0)	$ 15.39
Nonvested at December 31, 2007	4.4	$ 27.78

* Performance-based shares are valued at the end-of-period market price until certification that the performance objectives have been completed. Upon certification, these shares are valued at that day's end-of-period market price. All other shares are valued at the grant-date market price.

Other restricted stock unit information

	2007	2006	2005
Weighted-average grant date fair value of restricted stock units granted during the year, per share	$30.79	$23.39	$19.35
Total fair value of restricted stock units vested during the year ($'s in millions)	$ 33	$ 15	$ 14

Performance-based shares granted under the Plan represent 38 percent of nonvested restricted stock units outstanding at December 31, 2007. These grants are generally earned at the end of a three-year period based on actual performance against a performance target. Expense associated with these performance-based grants is recognized in periods after performance targets are established. Based on the extent to which certain financial targets are achieved, vested shares may range from zero percent to 200 percent of the original grant amount.

Note 14. Financial Instruments, Derivatives, Guarantees and Concentration of Credit Risk

Financial Instruments

Fair-value methods

We use the following methods and assumptions in estimating our fair-value disclosures for financial instruments:

Cash and cash equivalents and restricted cash: The carrying amounts reported in the balance sheet approximate fair value due to the short-term maturity of these instruments.

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Other securities, notes and other noncurrent receivables, structured indemnity settlement obligation, margin deposits, and customer margin deposits payable: The carrying amounts reported in the balance sheet approximate fair value as these instruments have interest rates approximating market. *Other securities* in the table below consists of auction rate securities and held-to-maturity securities and are reported, along with margin deposits, in *other current assets and deferred charges* in the Consolidated Balance Sheet.

Long-term debt: The fair value of our publicly traded long-term debt is valued using indicative year-end traded bond market prices. Private debt is valued based on the prices of similar securities with similar terms and credit ratings. At December 31, 2007 and 2006, approximately 90 percent and 87 percent, respectively, of our long-term debt was publicly traded.

Guarantees: The *guarantees* represented in the table below consist primarily of guarantees we have provided in the event of nonpayment by our previously owned communications subsidiary, Williams Communications Group (WilTel), on certain lease performance obligations. To estimate the fair value of the guarantees, the estimated default rate is determined by obtaining the average cumulative issuer-weighted corporate default rate for each guarantee based on the credit rating of WilTel's current owner and the term of the underlying obligation. The default rates are published by Moody's Investors Service.

Energy derivatives: Energy derivatives include:

- Futures contracts;
- Forward contracts;
- Swap agreements;
- Option contracts.

The fair value of energy derivatives is determined based on the nature of the underlying transaction and the market in which the transaction is executed. We execute most of these transactions on an organized commodity exchange or in over-the-counter markets in which quoted prices exist for active periods. For contracts with terms that exceed the time period for which actively quoted prices are available, we determine fair value by estimating commodity prices during the illiquid periods utilizing internally developed valuations incorporating information obtained from commodity prices in actively quoted markets, quoted prices in less active markets, prices reflected in current transactions, and other market fundamental analysis.

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Carrying amounts and fair values of our financial instruments

Asset (Liability)	2007 Carrying Amount	2007 Fair Value	2006 Carrying Amount	2006 Fair Value
	(Millions)			
Cash and cash equivalents	$ 1,699	$ 1,699	$ 2,269	$ 2,269
Restricted cash (current and noncurrent)	127	127	126	126
Other securities	20	20	103	103
Notes and other noncurrent receivables	4	4	4	4
Cost based investments (see Note 3)	25	(a)	52	(a)
Long-term debt, including current portion (see Note 11)(b)	(7,890)	(8,729)	(8,012)	(8,480)
Structured indemnity settlement obligation	—	—	(34)	(34)
Margin deposits	76	76	59	59
Customer margin deposits payable	(10)	(10)	(129)	(129)
Guarantees	(40)	(34)	(42)	(35)
Net energy derivatives:				
Energy commodity cash flow hedges(d)	(268)	(268)	365	365
Other energy derivatives(d)	(100)	(100)	70	70
Other derivatives(c)	—	—	2	2

(a) These investments are primarily in nonpublicly traded companies for which it is not practicable to estimate fair value.

(b) Excludes capital leases.

(c) Consists of nonenergy cash flow hedges.

(d) A portion of these derivatives is included in assets and liabilities of discontinued operations. (See Note 2.)

Energy Derivatives

Our energy derivative contracts include the following:

Futures contracts: Futures contracts are standardized commitments through an organized commodity exchange to either purchase or sell a commodity at a future date for a specified price. Futures are generally settled in cash, but may be settled through delivery of the underlying commodity. The fair value of these contacts is generally determined using quoted prices.

Forward contracts: Forward contracts are over-the-counter commitments to either purchase or sell a commodity at a future date for a specified price, which involve physical delivery of energy commodities, and may contain either fixed or variable pricing terms. Forward contracts are valued based on prices of the underlying energy commodities over the contract life and contractual or notional volumes with the resulting expected future cash flows discounted to a present value using a risk-free market interest rate.

Swap agreements: Swap agreements require us to make payments to (or receive payments from) counterparties based upon the differential between a fixed and variable price or between variable prices of energy commodities at different locations. Swap agreements are valued based on prices of the underlying energy commodities over the contract life and contractual or notional volumes with the resulting expected future cash flows discounted to a present value using a risk-free market interest rate.

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Option contracts: Physical and financial option contracts give the buyer the right to exercise the option and receive the difference between a predetermined strike price and a market price at the date of exercise. An option to purchase and an option to sell can be combined in an instrument called a collar to set a minimum and maximum transaction price. These contracts are valued based on option pricing models considering prices of the underlying energy commodities over the contract life, volatility of the commodity prices, contractual volumes, estimated volumes under option and other arrangements, and a risk-free market interest rate.

Energy commodity cash flow hedges

We are exposed to market risk from changes in energy commodity prices within our operations. We utilize derivatives to manage our exposure to the variability in expected future cash flows from forecasted purchases and sales of natural gas and forecasted sales of natural gas liquids (NGLs) attributable to commodity price risk. Certain of these derivatives have been designated as cash flow hedges under SFAS No. 133.

Our Exploration & Production segment produces, buys and sells natural gas at different locations throughout the United States. To reduce exposure to a decrease in revenues from fluctuations in natural gas market prices, we enter into natural gas futures contracts, swap agreements, and financial option contracts to mitigate the price risk on forecasted sales of natural gas. We have also entered into basis swap agreements to reduce the locational price risk associated with our producing basins. Exploration & Production's cash flow hedges are expected to be highly effective in offsetting cash flows attributable to the hedged risk during the term of the hedge. However, ineffectiveness may be recognized primarily as a result of locational differences between the hedging derivative and the hedged item.

Our Midstream segment produces and sells NGLs at different locations throughout the United States. To reduce exposure to a decrease in revenues from fluctuations in NGL market prices, we hedge price risk by entering into NGL swap agreements, financial forward contracts, and financial option contracts to mitigate the price risk on forecasted sales of NGLs. Midstream's cash flow hedges are expected to be highly effective in offsetting cash flows attributable to the hedged risk during the term of the hedge. However, ineffectiveness may be recognized primarily as a result of locational differences between the hedging derivative and the hedged item.

Changes in the fair value of our cash flow hedges are deferred in other comprehensive income and are reclassified into *revenues* in the same period or periods in which the hedged forecasted purchases or sales affect earnings, or when it is probable that the hedged forecasted transaction will not occur by the end of the originally specified time period. During 2006, we reclassified approximately $1 million of net gains from other comprehensive income to earnings as a result of the discontinuance of cash flow hedges because the forecasted transaction did not occur by the end of the originally specified time period. In second-quarter 2007, we recognized a net gain of $429 million (reported in *revenues* of discontinued operations) associated with the reclassification of deferred net hedge gains of our former power business from *accumulated other comprehensive income/loss* to earnings. This reclassification was based on the determination that the forecasted transactions related to the derivative cash flow hedges being sold to Bear Energy, LP were probable of not occurring. See Note 2 for further discussion. Approximately $14 million of net losses and $17 million of net gains from hedge ineffectiveness are included in *revenues* during 2007 and 2006, respectively. For 2007 and 2006, there are no derivative gains or losses excluded from the assessment of hedge effectiveness. As of December 31, 2007, we have hedged portions of future cash flows associated with anticipated energy commodity purchases and sales for up to three years. Based on recorded values at December 31, 2007, approximately $35 million of net losses (net of income tax benefit of $22 million) will be reclassified into earnings within the next year. These recorded values are based on market prices of the commodities as of December 31, 2007. Due to the volatile nature of commodity prices and changes in the creditworthiness of counterparties, actual gains or losses realized in 2008 will likely differ from these values. These gains or losses will offset net losses or gains that will be realized in earnings from previous unfavorable or favorable market movements associated with underlying hedged transactions.

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Other energy derivatives

Our Gas Marketing Services and Exploration & Production segments have other energy derivatives that have not been designated or do not qualify as SFAS No. 133 hedges. As such, the net change in their fair value is recognized in *revenues* in the Consolidated Statement of Income. Even though they do not qualify for hedge accounting (see *derivative instruments and hedging activities* in Note 1 for a description of hedge accounting), certain of these derivatives hedge our future cash flows on an economic basis.

Other energy-related contracts

We also hold significant nonderivative energy-related contracts, such as storage and transportation agreements, in our Gas Marketing Services portfolio. These have not been included in the financial instruments table above or in our Consolidated Balance Sheet because they are not derivatives as defined by SFAS No. 133.

Guarantees

In addition to the guarantees and payment obligations discussed elsewhere in these footnotes (see Notes 3 and 15), we have issued guarantees and other similar arrangements with off-balance sheet risk as discussed below.

In connection with agreements executed prior to our acquisition of Transco to resolve take-or-pay and other contract claims and to amend gas purchase contracts, Transco entered into certain settlements with producers which may require the indemnification of certain claims for additional royalties that the producers may be required to pay as a result of such settlements. Transco, through its agent, Gas Marketing Services, continues to purchase gas under contracts which extend, in some cases, through the life of the associated gas reserves. Certain of these contracts contain royalty indemnification provisions that have no carrying value. Producers have received certain demands and may receive other demands, which could result in claims pursuant to royalty indemnification provisions. Indemnification for royalties will depend on, among other things, the specific lease provisions between the producer and the lessor and the terms of the agreement between the producer and Transco. Consequently, the potential maximum future payments under such indemnification provisions cannot be determined. However, management believes that the probability of material payments is remote.

In connection with the 1993 public offering of units in the Williams Coal Seam Gas Royalty Trust (Royalty Trust), our Exploration & Production segment entered into a gas purchase contract for the purchase of natural gas in which the Royalty Trust holds a net profits interest. Under this agreement, we guarantee a minimum purchase price that the Royalty Trust will realize in the calculation of its net profits interest. We have an annual option to discontinue this minimum purchase price guarantee and pay solely based on an index price. The maximum potential future exposure associated with this guarantee is not determinable because it is dependent upon natural gas prices and production volumes. No amounts have been accrued for this contingent obligation as the index price continues to substantially exceed the minimum purchase price.

We are required by certain foreign lenders to ensure that the interest rates received by them under various loan agreements are not reduced by taxes by providing for the reimbursement of any domestic taxes required to be paid by the foreign lender. The maximum potential amount of future payments under these indemnifications is based on the related borrowings. These indemnifications generally continue indefinitely unless limited by the underlying tax regulations and have no carrying value. We have never been called upon to perform under these indemnifications.

We have provided guarantees in the event of nonpayment by our previously owned communications subsidiary, WilTel, on certain lease performance obligations that extend through 2042. The maximum potential exposure is approximately $44 million at December 31, 2007, and $46 million at December 31, 2006. Our exposure declines systematically throughout the remaining term of WilTel's obligations. The carrying value of these guarantees is approximately $39 million at December 31, 2007.

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Former managing directors of Gulf Liquids are involved in litigation related to the construction of gas processing plants. Gulf Liquids has indemnity obligations to the former managing directors for legal fees and potential losses that may result from this litigation. Claims against these former managing directors have been settled and dismissed after payments on their behalf by directors and officers insurers. Some unresolved issues remain between us and these insurers, but no amounts have been accrued for any potential liability.

We have guaranteed the performance of a former subsidiary of our wholly owned subsidiary MAPCO Inc., under a coal supply contract. This guarantee was granted by MAPCO Inc. upon the sale of its former subsidiary to a third-party in 1996. The guaranteed contract provides for an annual supply of a minimum of 2.25 million tons of coal. Our potential exposure is dependent on the difference between current market prices of coal and the pricing terms of the contract, both of which are variable, and the remaining term of the contract. Given the variability of the terms, the maximum future potential payments cannot be determined. We believe that our likelihood of performance under this guarantee is remote. In the event we are required to perform, we are fully indemnified by the purchaser of MAPCO Inc.'s former subsidiary. This guarantee expires in December 2010 and has no carrying value.

Concentration of Credit Risk

Cash equivalents

Our cash equivalents consist of high-quality securities placed with various major financial institutions with credit ratings at or above BBB by Standard & Poor's or Baa1 by Moody's Investors Service.

Accounts and notes receivable

The following table summarizes concentration of receivables including those related to discontinued operations (see Note 2), net of allowances, by product or service at December 31, 2007 and 2006:

	2007	2006
	(Millions)	
Receivables by product or service:		
Sale or transportation of natural gas and related products	$1,139	$ 895
Sales of power and related services	55	270
Interest	5	39
Other	48	9
Total	$1,247	$1,213

Natural gas customers include pipelines, distribution companies, producers, gas marketers and industrial users primarily located in the eastern and northwestern United States, Rocky Mountains, Gulf Coast, Venezuela and Canada. Prior to the sale of substantially all of our power business, which was completed in November 2007, customers for power included the California Independent System Operator (ISO), the California Department of Water Resources, and other power marketers and utilities located throughout the United States. As a general policy, collateral is not required for receivables, but customers' financial condition and credit worthiness are evaluated regularly.

Derivative assets and liabilities

We have a risk of loss as a result of counterparties not performing pursuant to the terms of their contractual obligations. Counterparty performance can be influenced by changes in the economy and regulatory issues, among other factors. Risk of loss results from items including credit considerations and the regulatory environment for which a counterparty transacts. We attempt to minimize credit-risk exposure to derivative counterparties and brokers through formal credit policies, consideration of credit ratings from public ratings agencies, monitoring

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procedures, master netting agreements and collateral support under certain circumstances. Additional collateral support could include the following:

- Letters of credit;
- Payment under margin agreements;
- Guarantees of payment by credit worthy parties.

We also enter into master netting agreements to mitigate counterparty performance and credit risk.

The gross credit exposure from our derivative contracts, a portion of which is included in assets of discontinued operations (see Note 2), as of December 31, 2007, is summarized below.

Counterparty Type	Investment Grade(a)	Total
	(Millions)	
Gas and electric utilities	$ 78	$ 79
Energy marketers and traders	224	1,328
Financial institutions	1,302	1,302
Other	—	1
	$ 1,604	2,710
Credit reserves		(1)
Gross credit exposure from derivatives		$2,709

We assess our credit exposure on a net basis to reflect master netting agreements in place with certain counterparties. We offset our credit exposure to each counterparty with amounts we owe the counterparty under derivative contracts. The net credit exposure from our derivatives as of December 31, 2007, is summarized below.

Counterparty Type	Investment Grade(a)	Total
	(Millions)	
Gas and electric utilities	$ 17	$ 17
Energy marketers and traders	18	20
Financial institutions	45	45
Other	—	—
	$ 80	82
Credit reserves		(1)
Net credit exposure from derivatives		$ 81

(a) We determine investment grade primarily using publicly available credit ratings. We include counterparties with a minimum Standard & Poor's of BBB− or Moody's Investors Service rating of Baa3 in investment grade. We also classify counterparties that have provided sufficient collateral, such as cash, standby letters of credit, parent company guarantees, and property interests, as investment grade.

Revenues

In 2007, 2006 and 2005, there were no customers for which our sales exceeded 10 percent of our consolidated revenues.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Note 15. Contingent Liabilities and Commitments

Rate and Regulatory Matters and Related Litigation

Our interstate pipeline subsidiaries have various regulatory proceedings pending. As a result, a portion of the revenues of these subsidiaries has been collected subject to refund. We have accrued a liability for these potential refunds as of December 31, 2007, which we believe is adequate for any refunds that may be required.

We are party to pending matters involving pipeline transportation rates charged to our former Alaska refinery in prior periods. While we have no loss exposure in these matters, favorable resolution could result in refunds. In February 2008, the Alaska Supreme Court ruled in our favor in one of these cases. This ruling may be subject to further appeal.

Issues Resulting from California Energy Crisis

Our former power business was engaged in power marketing in various geographic areas, including California. Prices charged for power by us and other traders and generators in California and other western states in 2000 and 2001 were challenged in various proceedings, including those before the Federal Energy Regulatory Commission (FERC). These challenges included refund proceedings, summer 2002 90-day contracts, investigations of alleged market manipulation including withholding, gas indices and other gaming of the market, new long-term power sales to the State of California that were subsequently challenged and civil litigation relating to certain of these issues. We have entered into settlements with the State of California (State Settlement), major California utilities (Utilities Settlement), and others that substantially resolved each of these issues with these parties.

As a result of a 2006 Ninth Circuit Court of Appeals decision, which the U.S. Supreme Court has agreed to review, certain contracts that we entered into during 2000 and 2001 may be subject to partial refunds. These contracts, under which we sold electricity, totaled approximately $89 million in revenue. We expect the U.S. Supreme Court's decision in the second quarter 2008. While we are not a party to the cases involved in the appellate court decision under review, the buyer of electricity from us is a party to the cases and claims that we must refund to the buyer any loss it suffers due to the decision and the FERC's reconsideration of the contract terms at issue in the decision.

Certain other issues also remain open at the FERC and for other nonsettling parties.

Refund proceedings

Although we entered into the State Settlement and Utilities Settlement, which resolved the refund issues among the settling parties, we continue to have potential refund exposure to nonsettling parties, such as various California end users that did not participate in the Utilities Settlement. As a part of the Utilities Settlement, we funded escrow accounts that we anticipate will satisfy any ultimate refund determinations in favor of the nonsettling parties including interest on refund amounts that we might owe to settling and nonsettling parties. As part of the State Settlement, we were to pay an additional $45 million to the California Attorney General over three years. Upon the sale of our power business in November 2007 (see Note 2), we paid the entire remaining balance on a discounted basis.

We are also owed interest from counterparties in the California market during the refund period for which we have recorded a receivable totaling approximately $24 million at December 31, 2007. Collection of the interest and the payment of interest on refund amounts from the escrow accounts is subject to the conclusion of this proceeding. Therefore, we continue to participate in the FERC refund case and related proceedings.

Challenges to virtually every aspect of the refund proceedings, including the refund period, were and continue to be made to the Ninth Circuit Court of Appeals and the U.S. Supreme Court. In August 2006, the Ninth Circuit issued its order that largely upheld the FERC's prior rulings, but it expanded the types of transactions that were made subject to refund. This order is subject to further appeal. Because of our settlements, we do not expect that the

August 2006 decision will have a material impact on us. However, the final refund calculation has not been made because of the appeals and certain unclear aspects of the refund calculation process.

Reporting of Natural Gas-Related Information to Trade Publications

Civil suits based on allegations of manipulating published gas price indices have been brought against us and others, in each case seeking an unspecified amount of damages. We are currently a defendant in:

- State court litigation in California brought on behalf of certain business and governmental entities that purchased gas for their use.
- Class action litigation and other litigation originally filed in state court in Colorado, Kansas, Missouri, Tennessee and Wisconsin brought on behalf of direct and indirect purchasers of gas in those states. The Tennessee purchasers have appealed the Tennessee state court's February 2007 dismissal of their case. The Missouri case has been remanded to Missouri state court. The cases in the other jurisdictions have been removed and transferred to the federal court in Nevada. On February 19, 2008, the federal court granted summary judgment in the Colorado case in favor of us and most of the other defendants. We expect that the Colorado plaintiffs will appeal.

Mobile Bay Expansion

In December 2002, an administrative law judge at the FERC issued an initial decision in Transcontinental Gas Pipe Line Corporation's (Transco) 2001 general rate case which, among other things, rejected the recovery of the costs of Transco's Mobile Bay expansion project from its shippers on a "rolled-in" basis and found that incremental pricing for the Mobile Bay expansion project is just and reasonable. In March 2004, the FERC issued an Order on Initial Decision in which it reversed certain parts of the administrative law judge's decision and accepted Transco's proposal for rolled-in rates. Gas Marketing Services holds long-term transportation capacity on the Mobile Bay expansion project. If the FERC had adopted the decision of the administrative law judge on the pricing of the Mobile Bay expansion project and also required that the decision be implemented effective September 1, 2001, Gas Marketing Services could have been subject to surcharges of approximately $139 million, including interest, through December 31, 2007, in addition to increased costs going forward. Certain parties filed appeals in federal court seeking to overturn the FERC's ruling on the rolled-in rates. Gas Marketing Services has reached an agreement in principle to settle this matter for $10 million.

Environmental Matters

Continuing operations

Since 1989, our Transco subsidiary has had studies underway to test certain of its facilities for the presence of toxic and hazardous substances to determine to what extent, if any, remediation may be necessary. Transco has responded to data requests from the U.S. Environmental Protection Agency (EPA) and state agencies regarding such potential contamination of certain of its sites. Transco has identified polychlorinated biphenyl (PCB) contamination in compressor systems, soils and related properties at certain compressor station sites. Transco has also been involved in negotiations with the EPA and state agencies to develop screening, sampling and cleanup programs. In addition, Transco commenced negotiations with certain environmental authorities and other parties concerning investigative and remedial actions relative to potential mercury contamination at certain gas metering sites. The costs of any such remediation will depend upon the scope of the remediation. At December 31, 2007, we had accrued liabilities of $6 million related to PCB contamination, potential mercury contamination, and other toxic and hazardous substances. Transco has been identified as a potentially responsible party at various Superfund and state waste disposal sites. Based on present volumetric estimates and other factors, we have estimated our aggregate exposure for remediation of these sites to be less than $500,000, which is included in the environmental accrual discussed above.

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Beginning in the mid-1980s, our Northwest Pipeline subsidiary evaluated many of its facilities for the presence of toxic and hazardous substances to determine to what extent, if any, remediation might be necessary. Consistent with other natural gas transmission companies, Northwest Pipeline identified PCB contamination in air compressor systems, soils and related properties at certain compressor station sites. Similarly, Northwest Pipeline identified hydrocarbon impacts at these facilities due to the former use of earthen pits and mercury contamination at certain gas metering sites. The PCBs were remediated pursuant to a Consent Decree with the EPA in the late 1980s and Northwest Pipeline conducted a voluntary clean-up of the hydrocarbon and mercury impacts in the early 1990s. In 2005, the Washington Department of Ecology required Northwest Pipeline to reevaluate its previous mercury clean-ups in Washington. Consequently, Northwest Pipeline is conducting additional remediation activities at certain sites to comply with Washington's current environmental standards. At December 31, 2007, we have accrued liabilities totaling approximately $7 million for these costs. We expect that these costs will be recoverable through Northwest Pipeline's rates.

We also accrue environmental remediation costs for natural gas underground storage facilities, primarily related to soil and groundwater contamination. At December 31, 2007, we have accrued liabilities totaling approximately $4 million for these costs.

In July 2006, the Colorado Department of Public Health and Environment (CDPHE) issued a Notice of Violation (NOV) to Williams Production RMT Company related to operating permits for our Roan Cliffs and Hayburn gas plants in Garfield County, Colorado. We have met with the CDPHE to discuss the allegations contained in the NOV and have provided additional requested information to the agency.

On April 11, 2007, the New Mexico Environment Department's Air Quality Bureau (NMED) issued an NOV to Williams Four Corners, LLC that alleged various emission and reporting violations in connection with our Lybrook gas processing plant's flare and leak detection and repair program. The NMED proposed a penalty of approximately $3 million. We are discussing the basis for and the scope of the proposed penalty with the NMED.

On April 16, 2007, the CDPHE issued an NOV to Williams Production RMT Company related to alleged air permit violations at the Rifle Station natural gas dehydration facility located in Garfield County, Colorado. The Rifle Station facility had been shut down prior to our receipt of the NOV and, except for some minor operations, remains closed. We responded to the CDPHE's notice on May 15, 2007.

On April 27, 2007, the Wyoming Department of Environmental Quality (WDEQ) issued an NOV to Williams Production RMT Company that alleged violations of various Wyoming Pollution Discharge Elimination System permits for our coal bed methane gas production facilities in the state. We are discussing the matter with the WDEQ and expect the penalty to be approximately $48,000.

Williams Production RMT Company performed voluntary audits of its 2006 and 2007 compliance with state and federal air regulations. In June 2007, we disclosed to the CDPHE, pursuant to its audit immunity privilege, our facilities that were not in compliance. We also described corrective actions that had or would be taken to remedy the issues. In January 2008, the Colorado Attorney General's office informed us of its opinion that our disclosures do not qualify for the audit privilege immunity. We are currently negotiating with the CDPHE and the Attorney General's office about this matter.

By letter dated September 20, 2007, the EPA required our Transco subsidiary to provide information regarding natural gas compressor stations in the states of Mississippi and Alabama as part of the EPA's investigation of our compliance with the Clean Air Act. We have responded with the requested information.

Former operations, including operations classified as discontinued

In connection with the sale of certain assets and businesses, we have retained responsibility, through indemnification of the purchasers, for environmental and other liabilities existing at the time the sale was consummated, as described below.

Agrico

In connection with the 1987 sale of the assets of Agrico Chemical Company, we agreed to indemnify the purchaser for environmental cleanup costs resulting from certain conditions at specified locations to the extent such costs exceed a specified amount. At December 31, 2007, we have accrued liabilities of approximately $8 million for such excess costs.

Other

At December 31, 2007, we have accrued environmental liabilities totaling approximately $21 million related primarily to our:

- Potential indemnification obligations to purchasers of our former retail petroleum and refining operations;
- Former propane marketing operations, bio-energy facilities, petroleum products and natural gas pipelines;
- Discontinued petroleum refining facilities;
- Former exploration and production and mining operations.

In 2004, our Gulf Liquids subsidiary initiated a self-audit of all environmental conditions (air, water, and waste) at three facilities in Geismar, Sorrento, and Chalmette, Louisiana. The audit revealed numerous infractions of Louisiana environmental regulations and resulted in a Consolidated Compliance Order and Notice of Potential Penalty from the Louisiana Department of Environmental Quality (LDEQ). In October 2007, we paid the agreed $109,000 penalty to the LDEQ as a comprehensive multi-media settlement.

Certain of our subsidiaries have been identified as potentially responsible parties at various Superfund and state waste disposal sites. In addition, these subsidiaries have incurred, or are alleged to have incurred, various other hazardous materials removal or remediation obligations under environmental laws.

Summary of environmental matters

Actual costs incurred for these matters could be substantially greater than amounts accrued depending on the actual number of contaminated sites identified, the actual amount and extent of contamination discovered, the final cleanup standards mandated by the EPA and other governmental authorities and other factors, but the amount cannot be reasonably estimated at this time.

Other Legal Matters

Will Price (formerly Quinque)

In 2001, fourteen of our entities were named as defendants in a nationwide class action lawsuit in Kansas state court that had been pending against other defendants, generally pipeline and gathering companies, since 2000. The plaintiffs alleged that the defendants have engaged in mismeasurement techniques that distort the heating content of natural gas, resulting in an alleged underpayment of royalties to the class of producer plaintiffs and sought an unspecified amount of damages. The fourth amended petition, which was filed in 2003, deleted all of our defendant entities except two Midstream subsidiaries. All remaining defendants have opposed class certification and a hearing on plaintiffs' second motion to certify the class was held in April 2005. We are awaiting a decision from the court. The amount of any possible liability cannot be reasonably estimated at this time.

Grynberg

In 1998, the DOJ informed us that Jack Grynberg, an individual, had filed claims on behalf of himself and the federal government, in the United States District Court for the District of Colorado under the False Claims Act against us and certain of our wholly owned subsidiaries. The claims sought an unspecified amount of royalties allegedly not paid to the federal government, treble damages, a civil penalty, attorneys' fees, and costs. In

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

connection with our sales of Kern River Gas Transmission in 2002 and Texas Gas Transmission Corporation in 2003, we agreed to indemnify the purchasers for any liability relating to this claim, including legal fees. The maximum amount of future payments that we could potentially be required to pay under these indemnifications depends upon the ultimate resolution of the claim and cannot currently be determined. Grynberg had also filed claims against approximately 300 other energy companies alleging that the defendants violated the False Claims Act in connection with the measurement, royalty valuation and purchase of hydrocarbons. In 1999, the DOJ announced that it would not intervene in any of the Grynberg cases. Also in 1999, the Panel on Multi-District Litigation transferred all of these cases, including those filed against us, to the federal court in Wyoming for pre-trial purposes. Grynberg's measurement claims remained pending against us and the other defendants; the court previously dismissed Grynberg's royalty valuation claims. In May 2005, the court-appointed special master entered a report which recommended that the claims against our Gas Pipeline and Midstream subsidiaries be dismissed but upheld the claims against our Exploration & Production subsidiaries against our jurisdictional challenge. In October 2006, the District Court dismissed all claims against us and our wholly owned subsidiaries, and in November 2006, Grynberg filed his notice of appeal with the Tenth Circuit Court of Appeals.

In August 2002, Jack J. Grynberg, and Celeste C. Grynberg, Trustee on Behalf of the Rachel Susan Grynberg Trust, and the Stephen Mark Grynberg Trust, served us and one of our Exploration & Production subsidiaries with a complaint in the state court in Denver, Colorado. The complaint alleges that we have used mismeasurement techniques that distort the British Thermal Unit heating content of natural gas, resulting in the alleged underpayment of royalties to Grynberg and other independent natural gas producers. The complaint also alleges that we inappropriately took deductions from the gross value of their natural gas and made other royalty valuation errors. Under various theories of relief, the plaintiff is seeking actual damages of between $2 million and $20 million based on interest rate variations and punitive damages in the amount of approximately $1 million. In 2004, Grynberg filed an amended complaint against one of our Exploration & Production subsidiaries. This subsidiary filed an answer in January 2005, denying liability for the damages claimed. Trial in this case was originally set for May 2006, but the parties have negotiated an agreement dismissing the measurement claims and deferring further proceedings on the royalty claims until resolution of an appeal in another case. The amount of any possible liability cannot be reasonably estimated at this time.

Securities class actions

Numerous shareholder class action suits were filed against us in 2002 in the United States District Court for the Northern District of Oklahoma. The majority of the suits alleged that we and co-defendants, WilTel, previously an owned subsidiary known as Williams Communications, and certain corporate officers, acted jointly and separately to inflate the stock price of both companies. WilTel was dismissed as a defendant as a result of its bankruptcy. These cases were consolidated and an order was issued requiring separate amended consolidated complaints by our equity holders and WilTel equity holders. The underwriter defendants have requested indemnification and defense from these cases. If we grant the requested indemnifications to the underwriters, any related settlement costs will not be covered by our insurance policies. We covered the cost of defending the underwriters. In 2002, the amended complaints of the WilTel securities holders and of our securities holders added numerous claims. On February 9, 2007, the court gave its final approval to our settlement with our securities holders. We entered into indemnity agreements with certain of our insurers to ensure their timely payment related to this settlement. The carrying value of our estimated liability related to these agreements is immaterial because we believe the likelihood of any future performance is remote.

On July 6, 2007, the court granted various defendants' motions for summary judgment and entered judgment for us and the other defendants in the WilTel matter. The plaintiffs appealed the court's judgment. Any obligation of ours to the WilTel equity holders as a result of a settlement, or as a result of trial in the event of a successful appeal of the court's judgment, will not likely be covered by insurance because our insurance coverage has been fully utilized by the settlement described above. The extent of any such obligation is presently unknown and cannot be estimated, but it is reasonably possible that our exposure could materially exceed amounts accrued for this matter.

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

TAPS Quality Bank

One of our subsidiaries, Williams Alaska Petroleum, Inc. (WAPI), is actively engaged in administrative litigation being conducted jointly by the FERC and the Regulatory Commission of Alaska (RCA) concerning the Trans-Alaska Pipeline System (TAPS) Quality Bank. In 2004, the FERC and RCA presiding administrative law judges rendered their joint and individual initial decisions, and we accrued approximately $134 million based on our computation and assessment of ultimate ruling terms that were considered probable. Our additional potential refund liability terminated on March 31, 2004, when we sold WAPI's interests in the TAPS pipeline. We subsequently accrued additional amounts for interest.

In 2006, the FERC entered its final order (FERC Final Order), which the RCA adopted, and most of the parties appealed to the D.C. Circuit Court of Appeals. ExxonMobil also filed a similar appeal in the Alaska Superior Court. A key issue pending on appeal is the limited retroactive impact of the FERC Final Order that restricts our exposure for Quality Bank adjustment refunds to periods after February 1, 2000. ExxonMobil asserts that the FERC's reliance on the Highway Reauthorization Act as the basis for limiting the retroactive effect violates, among other things, the separation of powers under the U.S. Constitution by interfering with the FERC's independent decision-making role. We expect a decision from the U.S. Supreme Court on the constitutional issues in 2008.

On June 7, 2007, the FERC stated the Quality Bank Administrator was free to issue invoices without any further action by the FERC. The Quality Bank Administrator issued invoices on July 31, 2007. We estimate that our net obligation for these invoices could be as much as $124 million. This amount remains an estimate because WAPI has not received all invoices to be issued to WAPI that arise out of the Administrator's original invoices to third parties. Amounts accrued in excess of this estimated obligation will be retained pending resolution of all appeals.

Redondo Beach taxes

In February 2005, we and AES Redondo Beach, L.L.C. received a tax assessment letter from the city of Redondo Beach, California, in which the city asserted that approximately $33 million in back taxes and approximately $39 million in interest and penalties are owed related to natural gas used at the generating facility operated by AES Redondo Beach. Hearings were held in July 2005 and in September 2005 the tax administrator for the city issued a decision in which he found us jointly and severally liable with AES Redondo Beach for back taxes of approximately $36 million and interest and penalties of approximately $21 million. Both we and AES Redondo Beach filed notices of appeal that were heard at the city level. In December 2006, the city hearing officer for the appeal of the pre-2005 amounts issued a final decision affirming our utility user tax liability and reversing AES Redondo Beach's liability because the officer ruled that AES Redondo Beach is an exempt public utility. We appealed this decision to the Los Angeles Superior Court, and the city also appealed with respect to AES Redondo Beach. Those appeals were heard on January 25 and February 14, 2008. On April 30, 2007, we paid the city the protested amount of approximately $57 million in order to pursue its appeal. Despite the city hearing officer's unfavorable decision and the payment to preserve our appeal rights, we do not believe a contingent loss is probable.

The city's assessment of our liability for the periods from 1998 through September 2007 is approximately $72 million (inclusive of interest and penalties). We protested all these assessments and requested hearings on them. We and AES Redondo Beach also filed separate refund actions in Los Angeles Superior Court related to certain taxes paid since the initial 2005 notice of assessment. The refund actions are stayed pending the resolution of the appeals. In connection with the sale of our power business (see Note 2), we settled our dispute with AES Redondo Beach by equally sharing, for periods prior to the closing of the sale, any ultimate tax liability as well as the funding of amounts previously paid under protest.

Gulf Liquids litigation

Gulf Liquids contracted with Gulsby Engineering Inc. (Gulsby) and Gulsby-Bay for the construction of certain gas processing plants in Louisiana. National American Insurance Company (NAICO) and American Home

Assurance Company provided payment and performance bonds for the projects. In 2001, the contractors, and sureties filed multiple cases in Louisiana and Texas against Gulf Liquids and us.

In 2006, at the conclusion of the consolidated trial of the asserted contract and tort claims, the jury returned its actual and punitive damages verdict against us and Gulf Liquids. Based on our interpretation of the jury verdicts, we estimated exposure for actual damages of approximately $68 million plus potential interest of approximately $25 million, all of which have been accrued as of December 31, 2007. In addition, we concluded that it was reasonably possible that any ultimate judgment might have included additional amounts of approximately $199 million in excess of our accrual, which primarily represented our estimate of potential punitive damage exposure under Texas law.

From May through October 2007, the court entered seven post-trial orders in the case (interlocutory orders) which, among other things, overruled the verdict award of tort and punitive damages as well as any damages against us. The court also denied the plaintiffs' claims for attorneys' fees. On January 28, 2008, the court issued its judgment awarding damages against Gulf Liquids of approximately $11 million in favor of Gulsby and approximately $4 million in favor of Gulsby-Bay. If the judgment is upheld on appeal, our liability will be substantially less than the amount of our accrual for these matters.

Wyoming severance taxes

In August 2006, the Wyoming Department of Audit (DOA) assessed our subsidiary Williams Production RMT Company for additional severance tax and interest for the production years 2000 through 2002. In addition, the DOA notified us of an increase in the taxable value of our interests for ad valorem tax purposes. We disputed the DOA's interpretation of the statutory obligation and appealed this assessment to the Wyoming State Board of Equalization (SBOE). The SBOE upheld the assessment and remanded it to the DOA to address the disallowance of a credit. Apparently agreeing that we could not have known the DOA's position before January 2007, the SBOE did not award interest on the assessment. We estimate that the amount of the additional severance and ad valorem taxes to be approximately $4 million. The Wyoming Supreme Court has agreed to hear our appeal of the SBOE's determination. If the DOA prevails in its interpretation of our obligation and applies the same basis of assessment to subsequent periods, it is reasonably possible that we could owe a total of approximately $18 million to $20 million in additional taxes and interest from January 1, 2003, through December 31, 2007.

Royalty litigation

In September 2006, royalty interest owners in Garfield County, Colorado, filed a class action suit in Colorado state court alleging that we improperly calculated oil and gas royalty payments, failed to account for the proceeds that we received from the sale of gas and extracted products, improperly charged certain expenses, and failed to refund amounts withheld in excess of ad valorem tax obligations. The plaintiffs claim that the class might be in excess of 500 individuals and seek an accounting and damages. The parties have agreed to stay this action in order to participate in ongoing mediation.

Certain other royalty matters are currently being litigated by a federal regulatory agency and another Colorado producer. Although we are not a party to the litigation, the final outcome of that case might lead to a future unfavorable impact on our results of operations.

Other Divestiture Indemnifications

Pursuant to various purchase and sale agreements relating to divested businesses and assets, we have indemnified certain purchasers against liabilities that they may incur with respect to the businesses and assets acquired from us. The indemnities provided to the purchasers are customary in sale transactions and are contingent upon the purchasers incurring liabilities that are not otherwise recoverable from third parties. The indemnities

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

generally relate to breach of warranties, tax, historic litigation, personal injury, environmental matters, right of way and other representations that we have provided.

We sold a natural gas liquids pipeline system in 2002, and in July 2006, the purchaser of that system filed its complaint against us and our subsidiaries in state court in Houston, Texas. The purchaser alleges that we breached certain warranties under the purchase and sale agreement and seeks approximately $18 million in damages and our specific performance under certain guarantees. In 2006, we filed our answer to the purchaser's complaint denying all liability. The trial is scheduled to begin on September 15, 2008, and our prior suit filed against the purchaser in Delaware state court is stayed pending resolution of the Texas case.

At December 31, 2007, we do not expect any of the indemnities provided pursuant to the sales agreements to have a material impact on our future financial position. However, if a claim for indemnity is brought against us in the future, it may have a material adverse effect on results of operations in the period in which the claim is made.

In addition to the foregoing, various other proceedings are pending against us which are incidental to our operations.

Summary

Litigation, arbitration, regulatory matters, and environmental matters are subject to inherent uncertainties. Were an unfavorable ruling to occur, there exists the possibility of a material adverse impact on the results of operations in the period in which the ruling occurs. Management, including internal counsel, currently believes that the ultimate resolution of the foregoing matters, taken as a whole and after consideration of amounts accrued, insurance coverage, recovery from customers or other indemnification arrangements, will not have a materially adverse effect upon our future financial position.

Commitments

Commitments for construction and acquisition of property, plant and equipment are approximately $484 million at December 31, 2007.

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Note 16. Accumulated Other Comprehensive Loss

The table below presents changes in the components of *accumulated other comprehensive loss.*

	Income (Loss)							
				Pension Benefits		Other Postretirement Benefits		
	Cash Flow Hedges	Foreign Currency Translation	Minimum Pension Liability	Prior Service Cost	Net Actuarial Gain (Loss)	Prior Service Cost	Net Actuarial Gain	Total
	(Millions)							
Balance at December 31, 2004	$ (308)	$ 69	$ (5)	$ —	$ —	$ —	$ —	$(244)
2005 Change:								
Pre-income tax amount	(396)	11	1	—	—	—	—	(384)
Income tax benefit (provision)	151	—	—	—	—	—	—	151
Net reclassification into earnings of derivative instrument losses (net of a $111 million income tax benefit)	179	—	—	—	—	—	—	179
	(66)	11	1	—	—	—	—	(54)
Balance at December 31, 2005	(374)	80	(4)	—	—	—	—	(298)
2006 Change:								
Pre-income tax amount	423	(4)	(1)	—	—	—	—	418
Income tax benefit (provision)	(162)	—	—	—	—	—	—	(162)
Net reclassification into earnings of derivative instrument losses (net of a $82 million income tax benefit)	133	—	—	—	—	—	—	133
	394	(4)	(1)	—	—	—	—	389
Adjustment to initially apply SFAS No. 158:								
Pre-income tax amount	—	—	8	(6)	(243)*	(7)	(8)	(256)
Income tax benefit (provision)	—	—	(3)	2	93	3	10	105
	—	—	5	(4)	(150)	(4)	2	(151)
Balance at December 31, 2006	20	76	—	(4)	(150)	(4)	2	(60)
2007 Change:								
Pre-income tax amount	201	53	—	—	68	—	15	337
Income tax benefit (provision)	(77)	—	—	—	(26)	—	(6)	(109)
Net reclassification into earnings of derivative instrument gains (net of a $187 million income tax provision)	(301)**	—	—	—	—	—	—	(301)
Amortization included in net periodic benefit expense	—	—	—	—	19	2	—	21
Income tax benefit (provision) on amortization	—	—	—	—	(8)	(1)	—	(9)
	(177)	53	—	—	53	1	9	(61)
Balance at December 31, 2007	$ (157)	$ 129	$ —	$ (4)	$ (97)	$ (3)	$ 11	$(121)

* Includes $1 million for the Net Actuarial Loss of an equity method investee.

** Includes a $429 million reclassification into earnings of deferred net hedge gains related to the sale of our power business. (See Note 2.)

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Note 17. Segment Disclosures

Our reportable segments are strategic business units that offer different products and services. The segments are managed separately because each segment requires different technology, marketing strategies and industry knowledge. Our master limited partnership, Williams Partners L.P., is consolidated within our Midstream segment. (See Note 1.) Other primarily consists of corporate operations.

Performance Measurement

We currently evaluate performance based on *segment profit (loss)* from operations, which includes *segment revenues* from external and internal customers, *segment costs and expenses, depreciation, depletion and amortization, equity earnings (losses)* and *loss from investments* including impairments related to investments accounted for under the equity method. The accounting policies of the segments are the same as those described in Note 1. Intersegment sales are generally accounted for at current market prices as if the sales were to unaffiliated third parties.

Energy commodity hedging by our business units may be done through intercompany derivatives with our Gas Marketing Services segment which, in turn, enters into offsetting derivative contracts with unrelated third parties. Gas Marketing Services bears the counterparty performance risks associated with the unrelated third parties in these transactions. Additionally, beginning in the first quarter of 2007, hedges related to Exploration & Production may be entered into directly between Exploration & Production and third parties under its new credit agreement. (See Note 11.) Exploration & Production bears the counterparty performance risks associated with the unrelated third parties in these transactions.

Gas Marketing Services primarily supports our natural gas businesses by providing marketing and risk management services, which include marketing and hedging the gas produced by Exploration & Production, and procuring fuel and shrink gas and hedging natural gas liquids sales for Midstream. In addition, Gas Marketing manages various natural gas-related contracts such as transportation, storage, and related hedges, and provides services to third parties, such as producers.

External revenues of our Exploration & Production segment includes third-party oil and gas sales, which are more than offset by transportation expenses and royalties due third parties on intersegment sales.

The following geographic area data includes *revenues from external customers* based on product shipment origin and *long-lived assets* based upon physical location.

	United States	Other	Total
	(Millions)		
Revenues from external customers:			
2007	$ 10,137	$ 421	$10,558
2006	8,982	394	9,376
2005	9,466	315	9,781
Long-lived assets:			
2007	$ 16,279	$ 713	$16,992
2006	14,487	682	15,169
2005	12,667	740	13,407

Our foreign operations are primarily located in Venezuela, Canada, and Argentina. *Long-lived assets* are comprised of property, plant and equipment, goodwill and other intangible assets.

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The following table reflects the reconciliation of *segment revenues* and *segment profit (loss)* to *revenues* and *operating income (loss)* as reported in the Consolidated Statement of Income and *other financial information* related to *long-lived assets.*

	Exploration & Production	Gas Pipeline	Midstream Gas & Liquids	Gas Marketing Services	Other	Eliminations	Total
				(Millions)			
2007							
Segment revenues:							
External	$ (95)	$ 1,576	$ 5,142	$ 3,924	$ 11	$ —	$10,558
Internal	2,188	34	38	709	15	(2,984)	—
Total revenues	$ 2,093	$ 1,610	$ 5,180	$ 4,633	$ 26	$ (2,984)	$10,558
Segment profit (loss)	$ 756	$ 673	$ 1,072	$ (337)	$ (1)	$ —	$ 2,163
Less equity earnings	25	51	61	—	—	—	137
Segment operating income (loss)	$ 731	$ 622	$ 1,011	$ (337)	$ (1)	$ —	2,026
General corporate expenses							(161)
Total operating income							$ 1,865
Other financial information:							
Additions to long-lived assets	$ 1,717	$ 546	$ 610	$ —	$ 27	$ —	$ 2,900
Depreciation, depletion & amortization	$ 535	$ 315	$ 214	$ 7	$ 10	$ —	$ 1,081
2006							
Segment revenues:							
External	$ (189)	$ 1,336	$ 4,094	$ 4,128	$ 7	$ —	$ 9,376
Internal	1,677	12	65	921	20	(2,695)	—
Total revenues	$ 1,488	$ 1,348	$ 4,159	$ 5,049	$ 27	$ (2,695)	$ 9,376
Segment profit (loss)	$ 552	$ 467	$ 675	$ (195)	$ (13)	$ —	$ 1,486
Less equity earnings	22	37	40	—	—	—	99
Segment operating income (loss)	$ 530	$ 430	$ 635	$ (195)	$ (13)	$ —	1,387
General corporate expenses							(132)
Securities litigation settlement and related costs							(167)
Total operating income							$ 1,088
Other financial information:							
Additions to long-lived assets	$ 1,496	$ 913	$ 279	$ 1	$ 18	$ —	$ 2,707
Depreciation, depletion & amortization	$ 360	$ 282	$ 203	$ 7	$ 11	$ —	$ 863
2005							
Segment revenues:							
External	$ (202)	$ 1,395	$ 3,212	$ 5,366	$ 10	$ —	$ 9,781
Internal	1,471	18	79	969	17	(2,554)	—
Total revenues	$ 1,269	$ 1,413	$ 3,291	$ 6,335	$ 27	$ (2,554)	$ 9,781
Segment profit (loss)	$ 587	$ 586	$ 460	$ 9	$ (123)	$ —	$ 1,519
Less:							
Equity earnings (losses)	19	44	27	—	(24)	—	66
Loss from investments	—	—	(22)	—	(87)	—	(109)
Segment operating income (loss)	$ 568	$ 542	$ 455	$ 9	$ (12)	$ —	1,562
General corporate expenses							(145)
Securities litigation settlement and related costs							(9)
Total operating income							$ 1,408
Other financial information:							
Additions to long-lived assets	$ 795	$ 420	$ 133	$ 6	$ 5	$ —	$ 1,359
Depreciation, depletion & amortization	$ 254	$ 267	$ 194	$ 10	$ 12	$ —	$ 737

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The following table reflects *total assets* and *equity method investments* by reporting segment.

	Total Assets			Equity Method Investments		
	December 31, 2007	December 31, 2006	December 31, 2005	December 31, 2007	December 31, 2006	December 31, 2005
	(Millions)					
Exploration & Production(1)	$ 8,692	$ 7,851	$ 8,672	$ 72	$ 59	$ 58
Gas Pipeline	8,624	8,332	7,581	483	432	439
Midstream Gas & Liquids	6,604	5,562	4,772	321	323	333
Gas Marketing Services(2)	4,437	5,519	11,464	—	—	—
Other	3,592	3,923	3,571	—	—	1
Eliminations(3)	(7,073)	(7,187)	(10,109)	—	—	—
	24,876	24,000	25,951	876	814	831
Discontinued operations	185	1,402	3,492	—	—	—
Total	$ 25,061	$ 25,402	$ 29,443	$ 876	$ 814	$ 831

(1) The 2006 decrease in Exploration & Production's total assets is due primarily to the fluctuations in derivative assets as a result of the impact of changes in commodity prices on existing derivative contracts. Exploration & Production's derivatives are primarily comprised of intercompany transactions with the Gas Marketing Services segment.

(2) The decrease in Gas Marketing Services' total assets for both 2007 and 2006 is due primarily to the fluctuations in derivative assets as a result of the impact of changes in commodity prices on existing forward derivative contracts. Gas Marketing Services' derivative assets are substantially offset by their derivative liabilities.

(3) The 2006 decrease in Eliminations is due primarily to the fluctuations in the intercompany derivative balances.

Note 18. Subsequent Events

In January 2008, we sold a contractual right to a production payment on certain future international hydrocarbon production for approximately $148 million. We have received $118 million in cash and $29 million has been placed in escrow subject to certain post-closing conditions and adjustments. We will recognize a pre-tax gain of approximately $118 million in the first quarter of 2008 related to the initial cash received. As a result of the contract termination, we have no further interests associated with the crude oil concession, which is located in Peru. We had obtained these interests through our acquisition of Barrett Resources Corporation in 2001.

During third-quarter 2007, we formed Williams Pipeline Partners L.P. (WMZ) to own and operate natural gas transportation and storage assets. In January 2008, WMZ completed its initial public offering of 16.25 million common units at a price of $20.00 per unit. In February 2008, the underwriters also exercised their right to purchase an additional 1.65 million common units at the same price. A subsidiary of ours serves as the general partner of WMZ. The initial asset of the partnership is a 35 percent interest in Northwest Pipeline GP, formerly Northwest Pipeline Corporation. Upon completion of the transaction, we hold approximately 47.7 percent of the interests in WMZ including the interests of the general partner. In accordance with EITF Issue No. 04-5 (see Note 1), WMZ will continue to be consolidated within our Gas Pipeline segment due to our control through the general partner, which is wholly owned by us.

At December 31, 2007, we held all of Williams Partners L.P.'s seven million subordinated units outstanding. In February 2008, all of these subordinated units were converted into common units due to factors which resulted in the termination of the subordination period. As a result, we will recognize a decrease to minority interest and a corresponding increase to stockholders' equity of approximately $1.2 billion in the first quarter of 2008.

THE WILLIAMS COMPANIES, INC.

QUARTERLY FINANCIAL DATA
(Unaudited)

Summarized quarterly financial data are as follows (millions, except per-share amounts).

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2007				
Revenues	$ 2,368	$ 2,824	$ 2,860	$ 2,506
Costs and operating expenses	1,843	2,180	2,222	1,834
Income from continuing operations	170	243	228	206
Net income	134	433	198	225
Basic earnings per common share:				
Income from continuing operations	.28	.40	.38	.35
Diluted earnings per common share:				
Income from continuing operations	.28	.40	.38	.34
2006				
Revenues	$ 2,387	$ 2,220	$ 2,512	$ 2,257
Costs and operating expenses	1,962	1,777	2,040	1,787
Income (loss) from continuing operations	132	(59)	113	161
Net income (loss)	132	(76)	106	147
Basic earnings (loss) per common share:				
Income (loss) from continuing operations	.22	(.10)	.19	.27
Diluted earnings (loss) per common share:				
Income (loss) from continuing operations	.22	(.10)	.19	.26

The sum of earnings per share for the four quarters may not equal the total earnings per share for the year due to changes in the average number of common shares outstanding and rounding.

Net income for fourth-quarter 2007 includes a $23 million adjustment to increase the tax provision relating to an income tax contingency and the following pre-tax items:

- $156 million mark-to-market loss recognized at Gas Marketing Services on a legacy derivative natural gas sales contract that we expect to assign to another party in 2008 under an asset transfer agreement that we executed in December 2007;
- $20 million accrual for litigation contingencies at Gas Marketing Services (see Note 4);
- $19 million in premiums, fees and expenses related to early debt retirement (see Note 11);
- $12 million of income related to a favorable litigation outcome at Midstream (see Note 4);
- $10 million charge related to an impairment of the Carbonate Trend pipeline at Midstream (see Note 4);
- $9 million charge related to the reserve for certain international receivables at Midstream;
- $6 million net loss, including transaction expenses, related to the sale of our discontinued power business (see summarized results of discontinued operations at Note 2).

Net income for third-quarter 2007 includes the following pre-tax items:

- $17 million of expenses related to the sale of our discontinued power business (see summarized results of discontinued operations at Note 2);
- $12 million of income associated with the payments received for a terminated firm transportation agreement on Northwest Pipeline’s Grays Harbor lateral (see Note 4).

THE WILLIAMS COMPANIES, INC.

QUARTERLY FINANCIAL DATA — (Continued)
(Unaudited)

Net income for second-quarter 2007 includes the following pre-tax items:

- $429 million gain associated with the reclassification of deferred net hedge gains to earnings related to the sale of our discontinued power business (see summarized results of discontinued operations at Note 2);
- $111 million impairment of the carrying value of certain derivative contracts related to the sale of our discontinued power business (see summarized results of discontinued operations at Note 2);
- $17 million of income associated with a change in estimate related to a regulatory liability at Northwest Pipeline (see Note 4);
- $15 million impairment of our Hazelton facility included in discontinued operations (see summarized results of discontinued operations at Note 2);
- $14 million of gains from the sales of cost-based investments (see Note 3);
- $14 million of expenses related to the sale of our discontinued power business (see summarized results of discontinued operations at Note 2);
- $6 million of income associated with the payments received for a terminated firm transportation agreement on Northwest Pipeline's Grays Harbor lateral (see Note 4).

Net income for the first-quarter 2007 includes the following pre-tax items:

- $8 million of income due to the reversal of a planned major maintenance accrual at Midstream.

Net income (loss) for fourth-quarter 2006 includes a $40 million reduction to the tax provision associated with a favorable U.S. Tax Court ruling, a $7 million increase to the tax provision associated with an adjustment to deferred income taxes (see Note 5) and the following pre-tax items:

- A $16 million impairment of a Venezuelan cost-based investment at Exploration & Production (see Note 3);
- A $15 million charge associated with an oil purchase contract related to our former Alaska refinery (see summarized results of discontinued operations at Note 2).

Net income (loss) for third-quarter 2006 includes the following pre-tax items:

- $13 million of income due to a reduction of contingent obligations at our former distributive power generation business (see summarized results of discontinued operations at Note 2);
- $11 million of expense related to an adjustment of an accounts payable accrual at Midstream;
- $6 million accrual for a loss contingency related to a former exploration business (see summarized results of discontinued operations at Note 2).

Net income (loss) for second-quarter 2006 includes the following pre-tax items:

- $161 million accrual related to our securities litigation settlement (see Note 15);
- $88 million accrual for Gulf Liquids litigation contingency and associated interest expense at Midstream (see Note 4);
- $19 million accrual for an adverse arbitration award related to our former chemical fertilizer business (see summarized results of discontinued operations at Note 2).

THE WILLIAMS COMPANIES, INC.

QUARTERLY FINANCIAL DATA — (Continued)
(Unaudited)

Net income (loss) for the first-quarter 2006 includes the following pre-tax items:

- $27 million premium and conversion expenses related to the convertible debenture conversion (see Note 12);
- $24 million gain on sale of certain receivables at Gas Marketing Services;
- $9 million of income related to the settlement of an international contract dispute at Midstream;
- $7 million associated with the reversal of an accrued litigation contingency due to a favorable court ruling and the related accrued interest income at our Gas Pipeline segment.

THE WILLIAMS COMPANIES, INC.

SUPPLEMENTAL OIL AND GAS DISCLOSURES
(Unaudited)

The following information pertains to our oil and gas producing activities and is presented in accordance with SFAS No. 69, "Disclosures About Oil and Gas Producing Activities." The information is required to be disclosed by geographic region. We have significant oil and gas producing activities primarily in the Rocky Mountain and Mid-continent areas of the United States. Additionally, we have international oil- and gas-producing activities, primarily in Argentina. However, proved reserves and revenues related to international activities are approximately 3.6 percent and 3.1 percent, respectively, of our total international and domestic proved reserves and revenues. The following information relates only to the oil and gas activities in the United States.

Capitalized Costs

	As of December 31,	
	2007	2006
	(Millions)	
Proved properties	$ 6,409	$ 5,027
Unproved properties	542	500
	6,951	5,527
Accumulated depreciation, depletion and amortization and valuation provisions	(1,754)	(1,260)
Net capitalized costs	$ 5,197	$ 4,267

- Excluded from capitalized costs are equipment and facilities in support of oil and gas production of $505 million and $338 million, net, for 2007 and 2006, respectively. The capitalized cost amounts for 2007 and 2006 do not include approximately $1 billion of goodwill related to the purchase of Barrett Resources Corporation (Barrett) in 2001.
- Proved properties include capitalized costs for oil and gas leaseholds holding proved reserves; development wells including uncompleted development well costs; and successful exploratory wells.
- Unproved properties consist primarily of acreage related to probable/possible reserves acquired through the Barrett acquisition in 2001. The balance is unproved exploratory acreage.

Costs Incurred

	For the Year Ended December 31,		
	2007	2006	2005
		(Millions)	
Acquisition	$ 82	$ 84	$ 45
Exploration	38	20	8
Development	1,374	1,173	724
	$1,494	$1,277	$777

- Costs incurred include capitalized and expensed items.
- Acquisition costs are as follows: The 2007 cost is primarily for additional land and reserve acquisitions in the Piceance and Fort Worth basins. The 2006 cost is primarily for additional land and reserve acquisitions in the Fort Worth basin. The 2005 costs primarily consist of a land and reserve acquisition in the Fort Worth basin and an additional land acquisition in the Arkoma basin.

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THE WILLIAMS COMPANIES, INC.

SUPPLEMENTAL OIL AND GAS DISCLOSURES — (Continued)
(Unaudited)

- Exploration costs include the costs of geological and geophysical activity, drilling and equipping exploratory wells determined to be dry holes, and the cost of retaining undeveloped leaseholds including lease amortization and impairments.
- Development costs include costs incurred to gain access to and prepare development well locations for drilling and to drill and equip development wells.

Results of Operations

	For the Year Ended December 31,		
	2007	2006	2005
	(Millions)		
Revenues:			
Oil and gas revenues	$1,725	$1,238	$1,072
Other revenues	304	186	144
Total revenues	2,029	1,424	1,216
Costs:			
Production costs	360	309	230
General & administrative	144	111	80
Exploration expenses	21	18	8
Depreciation, depletion & amortization	523	351	245
(Gains)/Losses on sales of interests in oil and gas properties	(1)	—	(31)
Other expenses	270	136	141
Total costs	1,317	925	673
Results of operations	712	499	543
Provision for income taxes	(273)	(174)	(217)
Exploration and production net income	$ 439	$ 325	$ 326

- Results of operations for producing activities consist of all related domestic activities within the Exploration & Production reporting unit. Other expenses in 2005 include a $6 million gain on sales of securities associated with a coal seam royalty trust.
- Oil and gas revenues consist primarily of natural gas production sold to the Gas Marketing Services subsidiary and includes the impact of hedges, including intercompany hedges.
- Other revenues and other expenses consist of activities within the Exploration & Production segment that are not a direct part of the producing activities. These nonproducing activities include acquisition and disposition of other working interest and royalty interest gas and the movement of gas from the wellhead to the tailgate of the respective plants for sale to the Gas Marketing Services subsidiary or third-party purchasers. In addition, other revenues include recognition of income from transactions which transferred certain nonoperating benefits to a third party.
- Production costs consist of costs incurred to operate and maintain wells and related equipment and facilities used in the production of petroleum liquids and natural gas. These costs also include production taxes other than income taxes and administrative expenses in support of production activity. Excluded are depreciation, depletion and amortization of capitalized acquisition, exploration and development costs.

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THE WILLIAMS COMPANIES, INC.

SUPPLEMENTAL OIL AND GAS DISCLOSURES — (Continued)
(Unaudited)

- Exploration expenses include the costs of geological and geophysical activity, drilling and equipping exploratory wells determined to be dry holes, and the cost of retaining undeveloped leaseholds including lease amortization and impairments.
- Depreciation, depletion and amortization includes depreciation of support equipment.

Proved Reserves

	2007	2006	2005
		(Bcfe)	
Proved reserves at beginning of period	3,701	3,382	2,986
Revisions	(106)	(113)	(12)
Purchases	19	41	28
Extensions and discoveries	863	669	615
Production	(334)	(277)	(224)
Sale of minerals in place	—	(1)	(11)
Proved reserves at end of period	4,143	3,701	3,382
Proved developed reserves at end of period	2,252	1,945	1,643

- The SEC defines proved oil and gas reserves (Rule 4-10(a) of Regulation S-X) as the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty are recoverable in future years from known reservoirs under existing economic and operating conditions. Our proved reserves consist of two categories, proved developed reserves and proved undeveloped reserves. Proved developed reserves are currently producing wells and wells awaiting minor sales connection expenditure, recompletion, additional perforations or borehole stimulation treatments. Proved undeveloped reserves are those reserves which are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Proved reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled or where it can be demonstrated with certainty that there is continuity of production from the existing productive formation.
- Natural gas reserves are computed at 14.73 pounds per square inch absolute and 60 degrees Fahrenheit. Crude oil reserves are insignificant and have been included in the proved reserves on a basis of billion cubic feet equivalents (Bcfe).

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The following is based on the estimated quantities of proved reserves and the year-end prices and costs. The average year-end natural gas prices used in the following estimates were $5.78, $4.81, and $6.95 per MMcfe at December 31, 2007, 2006, and 2005, respectively. Future income tax expenses have been computed considering available carry forwards and credits and the appropriate statutory tax rates. The discount rate of 10 percent is as prescribed by SFAS No. 69. Continuation of year-end economic conditions also is assumed. The calculation is based on estimates of proved reserves, which are revised over time as new data becomes available. Probable or possible reserves, which may become proved in the future, are not considered. The calculation also requires assumptions as to the timing of future production of proved reserves, and the timing and amount of future development and production costs. Of the $3,497 million of future development costs, $1,135 million, $1,126 million and $468 million are estimated to be spent in 2008, 2009 and 2010, respectively.

THE WILLIAMS COMPANIES, INC.

SUPPLEMENTAL OIL AND GAS DISCLOSURES — (Continued)
(Unaudited)

Numerous uncertainties are inherent in estimating volumes and the value of proved reserves and in projecting future production rates and timing of development expenditures. Such reserve estimates are subject to change as additional information becomes available. The reserves actually recovered and the timing of production may be substantially different from the reserve estimates.

Standardized Measure of Discounted Future Net Cash Flows

	At December 31, 2007	2006
	(Millions)	
Future cash inflows	$23,937	$17,821
Less:		
Future production costs	5,345	5,207
Future development costs	3,497	3,070
Future income tax provisions	5,416	3,350
Future net cash flows	9,679	6,194
Less 10 percent annual discount for estimated timing of cash flows	4,876	3,338
Standardized measure of discounted future net cash flows	$ 4,803	$ 2,856

Sources of Change in Standardized Measure of Discounted Future Net Cash Flows

	2007	2006	2005
		(Millions)	
Standardized measure of discounted future net cash flows beginning of period	$ 2,856	$ 5,281	$ 3,147
Changes during the year:			
Sales of oil and gas produced, net of operating costs	(1,426)	(1,179)	(1,222)
Net change in prices and production costs	2,019	(4,052)	2,358
Extensions, discoveries and improved recovery, less estimated future costs	2,163	647	1,310
Development costs incurred during year	738	881	723
Changes in estimated future development costs	(931)	(1,022)	(300)
Purchase of reserves in place, less estimated future costs	48	63	78
Sales of reserves in place, less estimated future costs	—	(2)	(31)
Revisions of previous quantity estimates	(266)	(140)	(28)
Accretion of discount	434	790	488
Net change in income taxes	(1,108)	1,468	(1,272)
Other	276	121	30
Net changes	1,947	(2,425)	2,134
Standardized measure of discounted future net cash flows end of period	$ 4,803	$ 2,856	$ 5,281

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THE WILLIAMS COMPANIES, INC.

SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS

	Beginning Balance	ADDITIONS Charged to Cost and Expenses	ADDITIONS Other	Deductions	Ending Balance
			(Millions)		
Year ended December 31, 2007:					
Allowance for doubtful accounts — accounts and notes receivable(a)	$ 15	$ 12	$ —	$ —	$ 27
Deferred tax asset valuation allowance(a)	36	21	—	—	57
Price-risk management credit reserves(a)	7	(6)(e)	—	—	1
Processing plant major maintenance accrual(b)	8	—	—	8(c)	—
Year ended December 31, 2006:					
Allowance for doubtful accounts — accounts and notes receivable(a)	86	4	(66)(f)	9(d)	15
Deferred tax asset valuation allowance(a)	37	(1)	—	—	36
Price-risk management credit reserves(a)	15	(8)(e)	—	—	7
Processing plant major maintenance accrual(b)	7	2	—	1	8
Year ended December 31, 2005:					
Allowance for doubtful accounts — accounts and notes receivable(a)	98	3	—	15(d)	86
Deferred tax asset valuation allowance(a)	62	(25)	—	—	37
Price-risk management credit reserves(a)	3	12(e)	—	—	15
Processing plant major maintenance accrual(b)	6	1	—	—	7

(a) Deducted from related assets.

(b) Included in *accrued liabilities* in 2006 and *other liabilities and deferred income* in 2005.

(c) Effective January 1, 2007, we adopted FASB Staff Position (FSP) No. AUG AIR-1, *Accounting for Planned Major Maintenance Activities*. As a result, we recognized as other income an $8 million reversal of an accrual for major maintenance on our Geismar ethane cracker. We did not apply the FSP retrospectively because the impact to our 2007 earnings, as well as the impact to prior periods, is not material. We have adopted the deferral method of accounting for these costs going forward.

(d) Represents balances written off, reclassifications, and recoveries.

(e) Included in *revenues*.

(f) During 2006, $66 million in previously reserved Enron receivables were sold.

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Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure***

None.

Item 9A. ***Controls and Procedures***

Evaluation of Disclosure Controls and Procedures

An evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d – 15(e) of the Securities Exchange Act) (Disclosure Controls) was performed as of the end of the period covered by this report. This evaluation was performed under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that these Disclosure Controls are effective at a reasonable assurance level.

Our management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our Disclosure Controls will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. We monitor our Disclosure Controls and make modifications as necessary; our intent in this regard is that the Disclosure Controls will be modified as systems change and conditions warrant.

Management's Report on Internal Control over Financial Reporting

See "Management's Report on Internal Control over Financial Reporting" set forth in Item 8, "Financial Statements and Supplementary Data."

Changes in Internal Controls Over Financial Reporting

There have been no changes during the fourth quarter of 2007 that have materially affected, or are reasonably likely to materially affect, our Internal Control over financial reporting.

Item 9B. ***Other Information***

None.

PART III

Item 10. ***Directors, Executive Officers and Corporate Governance***

The information regarding our directors and nominees for director required by Item 401 of Regulation S-K will be presented under the headings "Board of Directors — Board Committees," and "Election of Directors" in our Proxy Statement prepared for the solicitation of proxies in connection with our Annual Meeting of Stockholders to be held May 15, 2008 (Proxy Statement), which information is incorporated by reference herein.

Information regarding our executive officers required by Item 401(b) of Regulation S-K is presented at the end of Part I herein and captioned "Executive Officers of the Registrant" as permitted by General Instruction G(3) to Form 10-K and Instruction 3 to Item 401(b) of Regulation S-K.

Information required by Item 405 of Regulation S-K will be included under the heading "Compliance with Section 16 (a) of the Securities Exchange Act of 1934" in our Proxy Statement, which information is incorporated by reference herein.

Information required by paragraphs (c)(3), (d)(4) and (d)(5) of Item 407 of Regulation S-K will be included under the heading "Corporate Governance" in our Proxy Statement, which information in incorporated by reference herein.

We have adopted a Code of Ethics that applies to our Chief Executive Officer, Chief Financial Officer, and Controller, or persons performing similar functions. The Code of Ethics, together with our Corporate Governance Guidelines, the charters for each of our board committees, and our Code of Business Conduct applicable to all employees are available on our Internet website at *http://www.williams.com.* We will provide, free of charge, a copy of our Code of Ethics or any of our other corporate documents listed above upon written request to our Secretary at Williams, One Williams Center, Suite 4700, Tulsa, Oklahoma 74172. We intend to disclose any amendments to or waivers of the Code of Ethics on behalf of our Chief Executive Officer, Chief Financial Officer, Controller, and persons performing similar functions on our Internet website at *http://www.williams.com* under the Investor Relations caption, promptly following the date of any such amendment or waiver.

Item 11. *Executive Compensation*

The information required by Item 402 and paragraphs (e)(4) and (e)(5) of Item 407 of Regulation S-K regarding executive compensation will be presented under the headings "Board of Directors," "Executive Compensation," "Compensation committee interlocks and insider participation," and "Compensation committee report" in our Proxy Statement, which information is incorporated by reference herein. Notwithstanding the foregoing, the information provided under the heading "Compensation Committee Report" in our Proxy Statement is furnished and shall not be deemed to be filed for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, is not subject to the liabilities of that section and is not deemed incorporated by reference in any filing under the Securities Act of 1933, as amended.

Item 12. *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters*

The information regarding securities authorized for issuance under equity compensation plans required by Item 201 (d) of Regulation S-K and the security ownership of certain beneficial owners and management required by Item 403 of Regulation S-K will be presented under the headings "Equity Compensation Stock Plans" and "Security Ownership of Certain Beneficial Owners and Management" in our Proxy Statement, which information is incorporated by reference herein.

Item 13. *Certain Relationships and Related Transactions, and Director Independence*

The information regarding certain relationships and related transactions required by Item 404 and Item 407(a) of Regulation S-K will be presented under the heading "Certain Relationships and Related Transactions" and "Corporate Governance" in our Proxy Statement, which information is incorporated by reference herein.

Item 14. *Principal Accounting Fees and Services*

The information regarding our principal accountant fees and services required by Item 9(e) of Schedule 14A will be presented under the heading "Principal Accountant Fees and Services" in our Proxy Statement, which information is incorporated by reference herein.

PART IV

Item 15. ***Exhibits, Financial Statement Schedules***

(a) 1 and 2.

All other schedules have been omitted since the required information is not present or is not present in amounts sufficient to require submission of the schedule, or because the information required is included in the financial statements and notes thereto.

(a) 3 and (b). The exhibits listed below are filed as part of this annual report.

INDEX TO EXHIBITS

Exhibit No.		Description
3.1*	—	Restated Certificate of Incorporation, as supplemented (filed as Exhibit 3.1 to our Form 10-K filed March 11, 2005).
3.2*	—	Restated By-Laws (filed as Exhibit 3.2 to our current report on Form 8-K filed May 22, 2007).
4.1*	—	Form of Senior Debt Indenture between Williams and Bank One Trust company, N.A. (formerly The First National Bank of Chicago), as Trustee (filed as Exhibit 4.1 to our Form S-3 filed September 8, 1997).
4.2*	—	Form of Floating Rate Senior Note (filed as Exhibit 4.3 to our Form S-3 filed September 8, 1997).
4.3*	—	Form of Fixed Rate Senior Note (filed as Exhibit 4.4 to our Form S-3 filed September 8, 1997).
4.4*	—	Trust Company, N.A., as Trustee, dated as of January 17, 2001 (filed as Exhibit 4(j) to Form 10-K for the fiscal year ended December 31, 2000).
4.5*	—	Fifth Supplemental Indenture between Williams and Bank One Trust Company, N.A., as Trustee, dated as of January 17, 2001 (filed as Exhibit 4(k) to our Form 10-K for the fiscal year ended December 31, 2000).
4.6*	—	Seventh Supplemental Indenture dated March 19, 2002, between The Williams Companies, Inc. as Issuer and Bank One Trust Company, National Association, as Trustee (filed as Exhibit 4.1 to our Form 10-Q filed May 9, 2002).
4.7*	—	Form of Senior Debt Indenture between Williams Holdings of Delaware, Inc. and Citibank, N.A., as Trustee (filed as Exhibit 4.1 to Williams Holdings of Delaware, Inc.'s our Form 10-Q filed October 18, 1995).

Exhibit No.		Description
4.8*	—	First Supplemental Indenture dated as of July 31, 1999, among Williams Holdings of Delaware, Inc., Citibank, N.A., as Trustee (filed as Exhibit 4(o) to Form 10-K for the fiscal year ended December 31, 1999).
4.9*	—	Senior Indenture dated February 25, 1997, between MAPCO Inc. and Bank One Trust Company, N.A. (formerly The First National Bank of Chicago), as Trustee (filed as Exhibit 4.4.1 to MAPCO Inc.'s Amendment No. 1 to Form S-3 dated February 25, 1997).
4.10*	—	Supplemental Indenture No. 1 dated March 5, 1997, between MAPCO Inc. and Bank One Trust Company, N.A. (formerly The First National Bank of Chicago), as Trustee (filed as Exhibit 4(o) to MAPCO Inc.'s Form 10-K for the fiscal year ended December 31, 1997).
4.11*	—	Supplemental Indenture No. 2 dated March 5, 1997, between MAPCO Inc. and Bank One Trust Company, N.A. (formerly The First National Bank of Chicago), as Trustee (filed as Exhibit 4(p) to MAPCO Inc.'s Form 10-K for the fiscal year ended December 31, 1997).
4.12*	—	Supplemental Indenture No. 3 dated March 31, 1998, among MAPCO Inc., Williams Holdings of Delaware, Inc. and Bank One Trust Company, N.A. (formerly The First National Bank of Chicago), as Trustee (filed as Exhibit 4(j) to Williams Holdings of Delaware, Inc.'s Form 10-K for the fiscal year ended December 31, 1998).
4.13*	—	Supplemental Indenture No. 4 dated as of July 31, 1999, among Williams Holdings of Delaware, Inc., Williams and Bank One Trust Company, N.A. (formerly The First National Bank of Chicago), as Trustee (filed as Exhibit 4(q) to our Form 10-K for the fiscal year ended December 31, 1999).
4.14*	—	Indenture dated as of May 28, 2003, by and between The Williams Companies, Inc. and JPMorgan Chase Bank, as Trustee for the issuance of the 5.50% Junior Subordinated Convertible Debentures due 2033 (filed as Exhibit 4.2 to our Form 10-Q filed August 12, 2003).
4.15*	—	Amended and Restated Rights Agreement dated September 21, 2004 by and between The Williams Companies, Inc. and EquiServe Trust Company, N.A., as Rights Agent (filed as Exhibit 4.1 to our Form 8-K filed September 21, 2004).
4.16*	—	Amendment No. 1 dated May 18, 2007 to the Amended and Restated Rights Agreement dated September 21, 2004 (filed as Exhibit 4.1 to our current report on Form 8-K filed May 22, 2007).
4.17*	—	Amendment No. 2 dated October 12, 2007 to the Amended and Restated Rights Agreement dated September 21, 2004 (filed as Exhibit 4.1 to our current report on Form 8-K filed October 15, 2007).
4.18*	—	Senior Indenture, dated as of November 30, 1995, between Northwest Pipeline Corporation and Chemical Bank, Trustee with regard to Northwest Pipeline's 7.125% Debentures, due 2025 (filed as Exhibit 4.1 to Northwest Pipeline's Form S-3 filed September 14, 1995).
4.19*	—	Indenture dated as of June 22, 2006, between Northwest Pipeline Corporation and JPMorgan Chase Bank, N.A., as Trustee, with regard to Northwest Pipeline's $175 million aggregate principal amount of 7.00% Senior Notes due 2016 (filed as Exhibit 4.1 to Northwest Pipeline's Form 8-K dated June 23, 2006).
4.20*	—	Indenture, dated as of April 5, 2007, between Northwest Pipeline Corporation and The Bank of New York (filed as Exhibit 4.1 to Northwest Pipeline Corporation's (Commission File number 001-07414) current report on Form 8-K filed April 5, 2007).
4.21*	—	Senior Indenture dated as of July 15, 1996 between Transcontinental Gas Pipe Line Corporation and Citibank, N.A., as Trustee (filed as Exhibit 4.1 to Transcontinental Gas Pipe Line Corporation's Form S-3 dated April 2, 1996).
4.22*	—	Senior Indenture dated as of January 16, 1998 between Transcontinental Gas Pipe Line Corporation and Citibank, N.A., as Trustee (filed as Exhibit 4.1 to Transcontinental Gas Pipe Line Corporation's Form S-3 dated September 8, 1997).
4.23*	—	Indenture dated as of August 27, 2001 between Transcontinental Gas Pipe Line Corporation and Citibank, N.A., as Trustee (filed as Exhibit 4.1 to Transcontinental Gas Pipe Line Corporation's Form S-4 dated November 8, 2001).

Exhibit No.		Description
4.24*	—	Indenture dated as of July 3, 2002 between Transcontinental Gas Pipe Line Corporation and Citibank, N.A., as Trustee (filed as Exhibit 4.1 to The Williams Companies Inc.'s Form 10-Q for the quarterly period ended June 30, 2002).
4.25*	—	Indenture dated December 17, 2004 between Transcontinental Gas Pipe Line Corporation and JPMorgan Chase Bank, N.A., as Trustee (filed as Exhibit 4.1 to Transcontinental Gas Pipe Line Corporation's Form 8-K filed December 21, 2004).
4.26*	—	Indenture dated as of April 11, 2006, between Transcontinental Gas Pipe Line Corporation and JPMorgan Chase Bank, N.A., as Trustee with regard to Transcontinental Gas Pipe Line's $200 million aggregate principal amount of 6.4% Senior Note due 2016 (filed as Exhibit 4.1 to Transcontinental Gas Pipe Line Corporation's Form 8-K dated April 11, 2006).
4.27*	—	Indenture dated June 20, 2006, by and among Williams Partners L.P., Williams Partners Finance Corporation and JPMorgan Chase Bank, N.A. (filed as Exhibit 4.1 to Williams Partners L.P. Form 8-K filed June 20, 2006).
4.28*	—	Indenture dated December 13, 2006, by and among Williams Partners L.P., Williams Partners Finance Corporation and The Bank of New York (filed as Exhibit 4.1 to Williams Partners L.P. filed December 19, 2006).
10.1*	—	The Williams Companies, Inc. Supplemental Retirement Plan effective as of January 1, 1988 (filed as Exhibit 10(iii)(c) to our Form 10-K for the fiscal year ended December 31, 1987).
10.2*	—	First Amendment to The Williams Companies, Inc. Supplemental Retirement Plan effective as of April 1, 1988 (filed as Exhibit 10.2 to our Form 10-K for the fiscal year ended December 31, 2003).
10.3*	—	Second Amendment to The Williams Companies, Inc. Supplemental Retirement Plan effective as of January 1, 2002 and January 1, 2003 (filed as Exhibit 10.3 to our Form 10-K filed March, 11, 2005).
10.4*	—	The Williams Companies, Inc. Stock Plan for Non-Officer Employees (filed as Exhibit 10(iii)(g) to our Form 10-K for the fiscal year ended December 31, 1995).
10.5*	—	The Williams Companies, Inc. 1996 Stock Plan (filed as Exhibit A to our Proxy Statement dated March 27, 1996).
10.6*	—	The Williams Companies, Inc. 1996 Stock Plan for Non-employee Directors (filed as Exhibit B to our Proxy Statement dated March 27, 1996).
10.7*	—	The Williams Companies, Inc. 2001 Stock Plan (filed as Exhibit 10.7 to our Form 10-K for the fiscal year ended December 31, 2006).
10.8*	—	The Williams Companies, Inc. 2002 Incentive Plan for Non-Employee Director Stock Option Agreement (filed as Exhibit 10.8 to our Form 10-K for the fiscal year ended December 31, 2006).
10.9*	—	Indemnification Agreement effective as of August 1, 1986, among Williams, members of the Board of Directors and certain officers of Williams (filed as Exhibit 10(iii)(e) to our Form 10-K for the year ended December 31, 1986).
10.10*	—	Form of 2004 Deferred Stock Agreement among Williams and certain employees and officers (filed as Exhibit 10.12 to our Form 10-K filed March 11, 2005).
10.11*	—	Form of 2004 Performance-Based Deferred Stock Agreement among Williams and executive officers (filed as Exhibit 10.13 to our Form 10-K filed March 11, 2005).
10.12*	—	Form of Stock Option Agreement among Williams and certain employees and officers (filed as Exhibit 99.1 to our Form 8-K filed March 2, 2005).
10.13*	—	Form of 2005 Deferred Stock Agreement among Williams and certain employees and officers (filed as Exhibit 99.2 to our Form 8-K filed March 2, 2005).
10.14*	—	Form of 2005 Performance-Based Deferred Stock Agreement among Williams and executive officers (filed as Exhibit 99.3 to our Form 8-K filed March 2, 2005).
10.15*	—	Form of 2006 Deferred Stock Agreement among Williams and certain employees and officers (filed as Exhibit 99.1 to our Form 8-K filed March 7, 2006).

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Exhibit No.		Description
10.16*	—	Form of 2006 Stock Option Agreement among Williams and certain employees and officers (filed as Exhibit 99.2 to our Form 8-K filed March 7, 2006).
10.17*	—	Form of 2006 Performance-Based Deferred Stock Agreement among Williams and certain employees and officers (filed as Exhibit 99.3 to our Form 8-K filed March 7, 2006).
10.18*	—	Form of 2007 Restricted Stock Unit Agreement among Williams and certain employees and officers (filed as Exhibit 99.1 to our current report on Form 8-K filed March 1, 2007).
10.19*	—	Form of 2007 Nonqualified Stock Option Agreement among Williams and certain employees and officers (filed as Exhibit 99.2 to our current report on Form 8-K filed March 1, 2007).
10.20*	—	Form of 2007 Performance-Based Restricted Stock Unit Agreement among Williams and certain employees and officers (filed as Exhibit 99.3 to our current report on Form 8-K filed March 1, 2007).
10.21*	—	The Williams Companies, Inc. 2001 Stock Plan (filed as Exhibit 4.1 to our Form S-8 filed August 1, 2001).
10.22*	—	The Williams Companies, Inc. 2002 Incentive Plan as amended and restated effective as of January 23, 2004 (filed as Exhibit 10.1 to our Form 10-Q filed on August 5, 2004).
10.23*	—	The Williams Companies, Inc. 2007 Incentive Plan (filed as Appendix C to our Definitive Proxy Statement 14A filed on April 10, 2007).
10.24*	—	The Williams Companies, Inc. Employee Stock Purchase Plan (filed as Appendix D to our Definitive Proxy Statement 14A filed on April 10, 2007).
10.25*	—	Form of Change in Control Severance Agreement between the Company and certain executive officers (filed as Exhibit 10.12 to our Form 10-Q filed November 14, 2002).
10.26*	—	Settlement Agreement, by and among the Governor of the State of California and the several other parties named therein and The Williams Companies, Inc. and Williams Energy Marketing & Trading Company dated November 11, 2002 (filed as Exhibit 10.79 to our Form 10-K for the fiscal year ended December 31, 2002).
10.27*	—	The Williams Companies, Inc. Severance Pay Plan as Amended and Restated effective October 28, 2003 (filed as Exhibit 10.21 to our Form 10-K for the fiscal year ended December 31, 2005).
10.28*	—	Amendment to The Williams Companies, Inc. Severance Pay Plan dated October 28, 2003 (filed as Exhibit 10.22 to our Form 10-K for the fiscal year ended December 31, 2005).
10.29*	—	Amendment to The Williams Companies, Inc. Severance Pay Plan dated June 1, 2004 (filed as Exhibit 10.23 to our Form 10-K for the fiscal year ended December 31, 2005).
10.30*	—	Amendment to The Williams Companies, Inc. Severance Pay Plan dated January 1, 2005 (filed as Exhibit 10.24 to our Form 10-K for the fiscal year ended December 31, 2005).
10.31*	—	Amendment Agreement, dated May 9, 2007, among The Williams Companies, Inc., Williams Partners L.P., Northwest Pipeline Corporation, Transcontinental Gas Pipe Line Corporation, certain banks, financial institutions and other institutional lenders and Citibank, N.A., as administrative agent (filed as Exhibit 10.1 to our current report on Form 8-K filed May 15, 2007).
10.32*	—	Amendment Agreement dated November 21, 2007 among The Williams Companies, Inc., Williams Partners L.P., Northwest Pipeline GP, Transcontinental Gas Pipe Line Corporation, certain banks, financial institutions and other institutional lenders and Citibank, N.A., as administrative agent (filed as Exhibit 10.1 to our Form 8-K filed November 28, 2007).
10.33*	—	Credit Agreement dated as of May 1, 2006, among The Williams Companies, Inc., Northwest Pipeline Corporation, Transcontinental Gas Pipe Line Corporation, and Williams Partners L.P., as Borrowers and Citibank, N.A., as Administrative Agent (filed as Exhibit 10.1 to our form 8-K filed May 1, 2006).
10.34*	—	U.S. $400,000,000 Five Year Credit Agreement dated January 20, 2005 among The Williams Companies, Inc., as Borrower, the Initial Lenders named herein, as Initial Lenders, the Initial Issuing Banks named herein, as Initial Issuing Banks and Citibank, N.A., as Agent (filed as Exhibit 10.3 to our Form 8-K filed on January 26, 2005).

Exhibit No.		Description
10.35*	—	U.S. $100,000,000 Five Year Credit Agreement dated January 20, 2005 among The Williams Companies, Inc., as Borrower, the Initial Lenders named herein, as Initial Lenders, the Initial Issuing Banks named herein, as Initial Issuing Banks and Citibank, N.A., as Agent (filed as Exhibit 10.4 to our Form 8-K filed on January 26, 2005).
10.36*	—	U.S. $500,000,000 Five Year Credit Agreement dated September 20, 2005 among The Williams Companies, Inc., as Borrower, the Initial Lenders named herein, as Initial Lenders, the Initial Issuing Banks named herein, as Initial Issuing Banks and Citibank, N.A., as Agent (filed as Exhibit 10.1 to our Form 8-K filed on September 26, 2005).
10.37*	—	U.S. $200,000,000 Five Year Credit Agreement dated September 20, 2005 among The Williams Companies, Inc., as Borrower, the Initial Lenders named herein, as Initial Lenders, the Initial Issuing Banks named herein, as Initial Issuing Banks and Citibank, N.A., as Agent (filed as Exhibit 10.2 to our Form 8-K filed on September 26, 2005).
10.38*	—	Assumption Agreement dated June 17, 2003 by and between The Williams Companies, Inc. and WEG Acquisitions, L.P. (filed as Exhibit 10.10 to our Form 10-Q filed August 12, 2003).
10.39*	—	Agreement for the Release of Certain Indemnification Obligations dated as of May 26, 2004 by and among Magellan Midstream Holdings, L.P., Magellan G.P. LLC and Magellan Midstream Partners, L.P., on the one hand, and The Williams Companies, Inc., Williams Energy Services, LLC, Williams Natural Gas Liquids, Inc. and Williams GP LLC, on the other hand (filed as Exhibit 10.6 to our Form 10-Q filed August 5, 2004).
10.40*	—	Master Professional Services Agreement dated as of June 1, 2004, by and between The Williams Companies, Inc. and International Business Machines Corporation (filed as Exhibit 10.2 to our Form 10-Q filed August 5, 2004).
10.41*	—	Amendment No. 1 to the Master Professional Services Agreement dated June 1, 2004, by and between The Williams Companies, Inc. and International Business Machines Corporation made as of June 1, 2004 (filed as Exhibit 10.3 to our Form 10-Q filed August 5, 2004).
10.42*	—	Purchase and Sale Agreement, dated November 16, 2006, by and among Williams Energy Services, LLC, Williams field Services Group, LLC, Williams Field Services Company, LLC Williams Partners GP LLC, Williams Partners L.P. and Williams Partners Operating LLC (incorporated by reference to Exhibit 2.1 to Williams Partners L.P.'s current report on Form 8-K (File No. 1-32599) filed on November 21, 2006) (filed as Exhibit 2.1 to our Form 8-K filed November 22, 2006).
10.43*	—	Credit Agreement dated February 23, 2007 among Williams Production RMT Company, Williams Production Company, LLC, Citibank, N.A., Citigroup Energy Inc., Calyon New York Branch, and the banks named therein, and Citigroup Global Markets Inc. and Calyon New York Branch as joint lead arrangers and co-book runners (filed as Exhibit 10.41 to our Form 10-K for the fiscal year ended December 31, 2006).
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10.45*	—	Credit Agreement dated as of December 11, 2007, by and among Williams Partners L.P., the lenders party hereto, Citibank, N.A., as Administrative Agent and Issuing Bank, and The Bank of Nova Scotia, as Swingline Lender (filed as Exhibit 10.5 to Williams Partners L.P. Form 8-K filed December 17, 2007).
10.46*	—	Contribution Conveyance and Assumption Agreement, dated January 24, 2008, among Williams Pipeline Partners L.P., Williams Pipeline Operating LLC, WPP Merger LLC, Williams Pipeline Partners Holdings LLC, Northwest Pipeline GP, Williams Pipeline GP LLC, Williams Gas Pipeline Company, LLC, WGPC Holdings LLC and Williams Pipeline Services Company (filed as Exhibit 10.2 to 1 to Williams Pipeline Partners L.P. Form 8-K filed January 30, 2008).
12	—	Computation of Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividend Requirements.
14*	—	Code of Ethics (filed as Exhibit 14 to Form 10-K for the fiscal year ended December 31, 2003).

Exhibit No.		Description
20*	—	Definitive Proxy Statement of Williams for 2008 (to be filed with the Securities and Exchange Commission on or before April 15, 2008).
21	—	Subsidiaries of the registrant.
23.1	—	Consent of Independent Registered Public Accounting Firm, Ernst & Young LLP.
23.2	—	Consent of Independent Petroleum Engineers and Geologists, Netherland, Sewell & Associates, Inc.
23.3	—	Consent of Independent Petroleum Engineers and Geologists, Miller and Lents, LTD.
24	—	Power of Attorney together with certified resolution.
31.1	—	Certification of the Chief Executive Officer pursuant to Rules 13a-14(a) and 15d-14(a) promulgated under the Securities Exchange Act of 1934, as amended, and Item 601(b)(31) of Regulation S-K, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	—	Certification of the Chief Financial Officer pursuant to Rules 13a-14(a) and 15d-14(a) promulgated under the Securities Exchange Act of 1934, as amended, and Item 601(b)(31) of Regulation S-K, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32	—	Certification of the Chief Executive Officer and the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Each such exhibit has heretofore been filed with the SEC as part of the filing indicated and is incorporated herein by reference.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

THE WILLIAMS COMPANIES, INC.
(Registrant)

By: /s/ BRIAN K. SHORE
Brian K. Shore
Attorney-in-Fact

Date: February 26, 2008

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ STEVEN J. MALCOLM* Steven J. Malcolm*	President, Chief Executive Officer and Chairman of the Board (Principal Executive Officer)	February 26, 2008
/s/ DONALD R. CHAPPEL* Donald R. Chappel*	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	February 26, 2008
/s/ TED T. TIMMERMANS* Ted T. Timmermans*	Controller (Principal Accounting Officer)	February 26, 2008
/s/ KATHLEEN B. COOPER* Kathleen B. Cooper*	Director	February 26, 2008
/s/ IRL F. ENGELHARDT* Irl F. Engelhardt*	Director	February 26, 2008
/s/ WILLIAM R. GRANBERRY* William R. Granberry*	Director	February 26, 2008
/s/ WILLIAM E. GREEN* William E. Green*	Director	February 26, 2008
/s/ JUANITA H. HINSHAW* Juanita H. Hinshaw*	Director	February 26, 2008
/s/ W.R. HOWELL* W.R. Howell*	Director	February 26, 2008
/s/ CHARLES M. LILLIS* Charles M. Lillis*	Director	February 26, 2008

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Signature	Title	Date
/s/ GEORGE A. LORCH* George A. Lorch*	Director	February 26, 2008
/s/ WILLIAM G. LOWRIE* William G. Lowrie*	Director	February 26, 2008
/s/ FRANK T. MACINNIS* Frank T. MacInnis*	Director	February 26, 2008
/s/ JANICE D. STONEY* Janice D. Stoney*	Director	February 26, 2008
By: /s/ BRIAN K. SHORE Brian K. Shore *Attorney-in-Fact*		February 26, 2008

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INDEX TO EXHIBITS

Exhibit No.		Description
3.1*	—	Restated Certificate of Incorporation, as supplemented (filed as Exhibit 3.1 to our Form 10-K filed March 11, 2005).
3.2*	—	Restated By-Laws (filed as Exhibit 3.2 to our current report on Form 8-K filed May 22, 2007).
4.1*	—	Form of Senior Debt Indenture between Williams and Bank One Trust company, N.A. (formerly The First National Bank of Chicago), as Trustee (filed as Exhibit 4.1 to our Form S-3 filed September 8, 1997).
4.2*	—	Form of Floating Rate Senior Note (filed as Exhibit 4.3 to our Form S-3 filed September 8, 1997).
4.3*	—	Form of Fixed Rate Senior Note (filed as Exhibit 4.4 to our Form S-3 filed September 8, 1997).
4.4*	—	Trust Company, N.A., as Trustee, dated as of January 17, 2001 (filed as Exhibit 4(j) to Form 10-K for the fiscal year ended December 31, 2000).
4.5*	—	Fifth Supplemental Indenture between Williams and Bank One Trust Company, N.A., as Trustee, dated as of January 17, 2001 (filed as Exhibit 4(k) to our Form 10-K for the fiscal year ended December 31, 2000).
4.6*	—	Seventh Supplemental Indenture dated March 19, 2002, between The Williams Companies, Inc. as Issuer and Bank One Trust Company, National Association, as Trustee (filed as Exhibit 4.1 to our Form 10-Q filed May 9, 2002).
4.7*	—	Form of Senior Debt Indenture between Williams Holdings of Delaware, Inc. and Citibank, N.A., as Trustee (filed as Exhibit 4.1 to Williams Holdings of Delaware, Inc.'s our Form 10-Q filed October 18, 1995).
4.8*	—	First Supplemental Indenture dated as of July 31, 1999, among Williams Holdings of Delaware, Inc., Citibank, N.A., as Trustee (filed as Exhibit 4(o) to Form 10-K for the fiscal year ended December 31, 1999).
4.9*	—	Senior Indenture dated February 25, 1997, between MAPCO Inc. and Bank One Trust Company, N.A. (formerly The First National Bank of Chicago), as Trustee (filed as Exhibit 4.4.1 to MAPCO Inc.'s Amendment No. 1 to Form S-3 dated February 25, 1997).
4.10*	—	Supplemental Indenture No. 1 dated March 5, 1997, between MAPCO Inc. and Bank One Trust Company, N.A. (formerly The First National Bank of Chicago), as Trustee (filed as Exhibit 4(o) to MAPCO Inc.'s Form 10-K for the fiscal year ended December 31, 1997).
4.11*	—	Supplemental Indenture No. 2 dated March 5, 1997, between MAPCO Inc. and Bank One Trust Company, N.A. (formerly The First National Bank of Chicago), as Trustee (filed as Exhibit 4(p) to MAPCO Inc.'s Form 10-K for the fiscal year ended December 31, 1997).
4.12*	—	Supplemental Indenture No. 3 dated March 31, 1998, among MAPCO Inc., Williams Holdings of Delaware, Inc. and Bank One Trust Company, N.A. (formerly The First National Bank of Chicago), as Trustee (filed as Exhibit 4(j) to Williams Holdings of Delaware, Inc.'s Form 10-K for the fiscal year ended December 31, 1998).
4.13*	—	Supplemental Indenture No. 4 dated as of July 31, 1999, among Williams Holdings of Delaware, Inc., Williams and Bank One Trust Company, N.A. (formerly The First National Bank of Chicago), as Trustee (filed as Exhibit 4(q) to our Form 10-K for the fiscal year ended December 31, 1999).
4.14*	—	Indenture dated as of May 28, 2003, by and between The Williams Companies, Inc. and JPMorgan Chase Bank, as Trustee for the issuance of the 5.50% Junior Subordinated Convertible Debentures due 2033 (filed as Exhibit 4.2 to our Form 10-Q filed August 12, 2003).
4.15*	—	Amended and Restated Rights Agreement dated September 21, 2004 by and between The Williams Companies, Inc. and EquiServe Trust Company, N.A., as Rights Agent (filed as Exhibit 4.1 to our Form 8-K filed September 21, 2004).
4.16*	—	Amendment No. 1 dated May 18, 2007 to the Amended and Restated Rights Agreement dated September 21, 2004 (filed as Exhibit 4.1 to our current report on Form 8-K filed May 22, 2007).
4.17*	—	Amendment No. 2 dated October 12, 2007 to the Amended and Restated Rights Agreement dated September 21, 2004 (filed as Exhibit 4.1 to our current report on Form 8-K filed October 15, 2007).
4.18*	—	Senior Indenture, dated as of November 30, 1995, between Northwest Pipeline Corporation and Chemical Bank, Trustee with regard to Northwest Pipeline's 7.125% Debentures, due 2025 (filed as Exhibit 4.1 to Northwest Pipeline's Form S-3 filed September 14, 1995).

Exhibit No.		Description
4.19*	—	Indenture dated as of June 22, 2006, between Northwest Pipeline Corporation and JPMorgan Chase Bank, N.A., as Trustee, with regard to Northwest Pipeline's $175 million aggregate principal amount of 7.00% Senior Notes due 2016 (filed as Exhibit 4.1 to Northwest Pipeline's Form 8-K dated June 23, 2006).
4.20*	—	Indenture, dated as of April 5, 2007, between Northwest Pipeline Corporation and The Bank of New York (filed as Exhibit 4.1 to Northwest Pipeline Corporation's (Commission File number 001-07414) current report on Form 8-K filed April 5, 2007).
4.21*	—	Senior Indenture dated as of July 15, 1996 between Transcontinental Gas Pipe Line Corporation and Citibank, N.A., as Trustee (filed as Exhibit 4.1 to Transcontinental Gas Pipe Line Corporation's Form S-3 dated April 2, 1996).
4.22*	—	Senior Indenture dated as of January 16, 1998 between Transcontinental Gas Pipe Line Corporation and Citibank, N.A., as Trustee (filed as Exhibit 4.1 to Transcontinental Gas Pipe Line Corporation's Form S-3 dated September 8, 1997).
4.23*	—	Indenture dated as of August 27, 2001 between Transcontinental Gas Pipe Line Corporation and Citibank, N.A., as Trustee (filed as Exhibit 4.1 to Transcontinental Gas Pipe Line Corporation's Form S-4 dated November 8, 2001).
4.24*	—	Indenture dated as of July 3, 2002 between Transcontinental Gas Pipe Line Corporation and Citibank, N.A., as Trustee (filed as Exhibit 4.1 to The Williams Companies Inc.'s Form 10-Q for the quarterly period ended June 30, 2002).
4.25*	—	Indenture dated December 17, 2004 between Transcontinental Gas Pipe Line Corporation and JPMorgan Chase Bank, N.A., as Trustee (filed as Exhibit 4.1 to Transcontinental Gas Pipe Line Corporation's Form 8-K filed December 21, 2004).
4.26*	—	Indenture dated as of April 11, 2006, between Transcontinental Gas Pipe Line Corporation and JPMorgan Chase Bank, N.A., as Trustee with regard to Transcontinental Gas Pipe Line's $200 million aggregate principal amount of 6.4% Senior Note due 2016 (filed as Exhibit 4.1 to Transcontinental Gas Pipe Line Corporation's Form 8-K dated April 11, 2006).
4.27*	—	Indenture dated June 20, 2006, by and among Williams Partners L.P., Williams Partners Finance Corporation and JPMorgan Chase Bank, N.A. (filed as Exhibit 4.1 to Williams Partners L.P. Form 8-K filed June 20, 2006).
4.28*	—	Indenture dated December 13, 2006, by and among Williams Partners L.P., Williams Partners Finance Corporation and The Bank of New York (filed as Exhibit 4.1 to Williams Partners L.P. filed December 19, 2006).
10.1*	—	The Williams Companies, Inc. Supplemental Retirement Plan effective as of January 1, 1988 (filed as Exhibit 10(iii)(c) to our Form 10-K for the fiscal year ended December 31, 1987).
10.2*	—	First Amendment to The Williams Companies, Inc. Supplemental Retirement Plan effective as of April 1, 1988 (filed as Exhibit 10.2 to our Form 10-K for the fiscal year ended December 31, 2003).
10.3*	—	Second Amendment to The Williams Companies, Inc. Supplemental Retirement Plan effective as of January 1, 2002 and January 1, 2003 (filed as Exhibit 10.3 to our Form 10-K filed March, 11, 2005).
10.4*	—	The Williams Companies, Inc. Stock Plan for Non-Officer Employees (filed as Exhibit 10(iii)(g) to our Form 10-K for the fiscal year ended December 31, 1995).
10.5*	—	The Williams Companies, Inc. 1996 Stock Plan (filed as Exhibit A to our Proxy Statement dated March 27, 1996).
10.6*	—	The Williams Companies, Inc. 1996 Stock Plan for Non-employee Directors (filed as Exhibit B to our Proxy Statement dated March 27, 1996).
10.7*	—	The Williams Companies, Inc. 2001 Stock Plan (filed as Exhibit 10.7 to our Form 10-K for the fiscal year ended December 31, 2006).
10.8*	—	The Williams Companies, Inc. 2002 Incentive Plan for Non-Employee Director Stock Option Agreement (filed as Exhibit 10.8 to our Form 10-K for the fiscal year ended December 31, 2006).
10.9*	—	Indemnification Agreement effective as of August 1, 1986, among Williams, members of the Board of Directors and certain officers of Williams (filed as Exhibit 10(iii)(e) to our Form 10-K for the year ended December 31, 1986).

Exhibit No.		Description
10.10*	—	Form of 2004 Deferred Stock Agreement among Williams and certain employees and officers (filed as Exhibit 10.12 to our Form 10-K filed March 11, 2005).
10.11*	—	Form of 2004 Performance-Based Deferred Stock Agreement among Williams and executive officers (filed as Exhibit 10.13 to our Form 10-K filed March 11, 2005).
10.12*	—	Form of Stock Option Agreement among Williams and certain employees and officers (filed as Exhibit 99.1 to our Form 8-K filed March 2, 2005).
10.13*	—	Form of 2005 Deferred Stock Agreement among Williams and certain employees and officers (filed as Exhibit 99.2 to our Form 8-K filed March 2, 2005).
10.14*	—	Form of 2005 Performance-Based Deferred Stock Agreement among Williams and executive officers (filed as Exhibit 99.3 to our Form 8-K filed March 2, 2005).
10.15*	—	Form of 2006 Deferred Stock Agreement among Williams and certain employees and officers (filed as Exhibit 99.1 to our Form 8-K filed March 7, 2006).
10.16*	—	Form of 2006 Stock Option Agreement among Williams and certain employees and officers (filed as Exhibit 99.2 to our Form 8-K filed March 7, 2006).
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10.18*	—	Form of 2007 Restricted Stock Unit Agreement among Williams and certain employees and officers (filed as Exhibit 99.1 to our current report on Form 8-K filed March 1, 2007).
10.19*	—	Form of 2007 Nonqualified Stock Option Agreement among Williams and certain employees and officers (filed as Exhibit 99.2 to our current report on Form 8-K filed March 1, 2007).
10.20*	—	Form of 2007 Performance-Based Restricted Stock Unit Agreement among Williams and certain employees and officers (filed as Exhibit 99.3 to our current report on Form 8-K filed March 1, 2007).
10.21*	—	The Williams Companies, Inc. 2001 Stock Plan (filed as Exhibit 4.1 to our Form S-8 filed August 1, 2001).
10.22*	—	The Williams Companies, Inc. 2002 Incentive Plan as amended and restated effective as of January 23, 2004 (filed as Exhibit 10.1 to our Form 10-Q filed on August 5, 2004).
10.23*	—	The Williams Companies, Inc. 2007 Incentive Plan (filed as Appendix C to our Definitive Proxy Statement 14A filed on April 10, 2007).
10.24*	—	The Williams Companies, Inc. Employee Stock Purchase Plan (filed as Appendix D to our Definitive Proxy Statement 14A filed on April 10, 2007).
10.25*	—	Form of Change in Control Severance Agreement between the Company and certain executive officers (filed as Exhibit 10.12 to our Form 10-Q filed November 14, 2002).
10.26*	—	Settlement Agreement, by and among the Governor of the State of California and the several other parties named therein and The Williams Companies, Inc. and Williams Energy Marketing & Trading Company dated November 11, 2002 (filed as Exhibit 10.79 to our Form 10-K for the fiscal year ended December 31, 2002).
10.27*	—	The Williams Companies, Inc. Severance Pay Plan as Amended and Restated effective October 28, 2003 (filed as Exhibit 10.21 to our Form 10-K for the fiscal year ended December 31, 2005).
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Exhibit No.		Description
10.46*	—	Contribution Conveyance and Assumption Agreement, dated January 24, 2008, among Williams Pipeline Partners L.P., Williams Pipeline Operating LLC, WPP Merger LLC, Williams Pipeline Partners Holdings LLC, Northwest Pipeline GP, Williams Pipeline GP LLC, Williams Gas Pipeline Company, LLC, WGPC Holdings LLC and Williams Pipeline Services Company (filed as Exhibit 10.2 to 1 to Williams Pipeline Partners L.P. Form 8-K filed January 30, 2008).
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23.1	—	Consent of Independent Registered Public Accounting Firm, Ernst & Young LLP.
23.2	—	Consent of Independent Petroleum Engineers and Geologists, Netherland, Sewell & Associates, Inc.
23.3	—	Consent of Independent Petroleum Engineers and Geologists, Miller and Lents, LTD.
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31.1	—	Certification of the Chief Executive Officer pursuant to Rules 13a-14(a) and 15d-14(a) promulgated under the Securities Exchange Act of 1934, as amended, and Item 601(b)(31) of Regulation S-K, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	—	Certification of the Chief Financial Officer pursuant to Rules 13a-14(a) and 15d-14(a) promulgated under the Securities Exchange Act of 1934, as amended, and Item 601(b)(31) of Regulation S-K, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32	—	Certification of the Chief Executive Officer and the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Each such exhibit has heretofore been filed with the SEC as part of the filing indicated and is incorporated herein by reference.

Section 2: EX-12 (COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES AND PREFERRED STOCK DIVIDEND REQUIREMENTS)

Exhibit 12

The Williams Companies, Inc.
Computation of Ratio of Earnings to Fixed Charges

	Years Ended December 31,				
	2007	2006	2005	2004	2003
	(Dollars in millions)				
Earnings:					
Income (loss) from continuing operations before income taxes and cumulative effect of change in accounting principles	$ 1,371	$ 558	$ 774	$ 299	$ (375)
Minority interest in income and preferred returns of consolidated subsidiaries	90	40	26	21	19
Less: Equity earnings, excluding proportionate share from 50% owned investees and unconsolidated majority-owned investee	(60)	(99)	(66)	(50)	(20)
Income (loss) from continuing operations before income taxes and cumulative effect of change in accounting principles, minority interest in income and preferred returns of consolidated subsidiaries and equity earnings	1,401	499	734	270	(376)
Add:					
Fixed charges:					
Interest accrued, including proportionate share from 50% owned investees and unconsolidated majority-owned investee (a)	709	694	680	822	1,274
Rental expense representative of interest factor	22	16	19	18	25
Preferred distributions	—	—	—	—	48
Total fixed charges	731	710	699	840	1,347
Distributed income of equity-method investees, excluding proportionate share from 50% owned investees and unconsolidated majority-owned investee	48	113	108	61	21
Less:					
Capitalized interest	(32)	(17)	(7)	(7)	(45)
Preferred distributions	—	—	—	—	(48)
Total earnings as adjusted	$ 2,148	$ 1,305	$ 1,534	$ 1,164	$ 899
Fixed charges	$ 731	$ 710	$ 699	$ 840	$ 1,347
Ratio of earnings to fixed charges	2.94	1.84	2.19	1.39	(b)

(a) Does not include interest related to income taxes, including interest related to FIN 48 liabilities, which is included in *provision for income taxes* on our Consolidated Statement of Income. See Note 5 of Notes to Consolidated Financial Statements.

(b) Earnings were inadequate to cover fixed charges by $448 million for the year ended December 31, 2003.

Section 3: EX-21 (SUBSIDIARIES OF THE REGISTRANT)

Exhibit 21

ENTITY	JURISDICTION
ACCROVEN SRL	Barbados
Alliance Canada Marketing L.P.	Alberta
Alliance Canada Marketing LTD	Alberta
Apco Argentina, Inc.	Cayman Islands
Apco Argentina, S.A.	Argentina
Apco Properties Ltd.	Cayman Islands
Arctic Fox Assets, Inc.	Delaware
Aspen Products Pipeline LLC	Delaware
Aux Sable Canada Ltd.	Alberta
Aux Sable Canada LP	Alberta
Aux Sable Liquid Products Inc.	Delaware
Aux Sable Liquid Products LP	Alberta
Bargath Inc.	Colorado
Barrett Fuels Corporation	Delaware
Barrett Resources International Corporation	Delaware
Baton Rouge Fractionators LLC	Delaware
Baton Rouge Pipeline LLC	Delaware
Beech Grove Processing Company	Tennessee
Bison Royalty LLC	Delaware
Black Marlin Pipeline Company	Texas
Carbon County UCG, Inc.	Delaware
Carbonate Trend Pipeline LLC	Delaware
Cardinal Operating Company	Delaware
Cardinal Pipeline Company, LLC	North Carolina
Castle Associates, L.P.	Delaware
ChoiceSeat, L.L.C.	Delaware
Diamond Elk, LLC	Colorado
Discovery Gas Transmission LLC	Delaware
Discovery Producer Services LLC	Delaware
Distributed Power Solutions L.L.C.	Delaware
E-Birchtree, LLC	Delaware
Eagle Gas Services, Inc.	Ohio
ESPAGAS USA, Inc.	Delaware
F T & T, Inc.	Delaware
Fishhawk Ranch, Inc.	Florida
FleetOne Inc.	Delaware
Fort Union Gas Gathering, L.L.C.	Delaware
Garrison, L.L.C.	Delaware
Goebel Gathering Company, L.L.C.	Delaware
Gulf Liquids Holdings LLC	Delaware
Gulf Liquids New River Project LLC	Delaware

Gulf Star Deepwater Services, LLC	Delaware
Gulfstream Management & Operating Services, L.L.C.	Delaware
Gulfstream Natural Gas System, L.L.C.	Delaware
Hazleton Fuel Management Company	Delaware
Hazleton Pipeline Company	Delaware
HI-BOL Pipeline Company	Delaware
Inland Ports, Inc.	Tennessee
Kiowa Gas Storage, L.L.C.	Delaware
Laughton, L.L.C.	Delaware
Liberty Operating Company	Delaware
Longhorn Enterprises of Texas, Inc.	Delaware
MAPCO Alaska Inc.	Alaska
MAPCO Inc.	Delaware
MAPL Investments, Inc.	Delaware
Marsh Resources, Inc.	Delaware
Mid-Continent Fractionation and Storage, LLC	Delaware
Millennium Energy Fund, L.L.C.	Delaware
Mockingbird Pipeline, L.P.	Delaware
Northwest Argentina Corporation	Utah
Northwest Land Company	Delaware
Northwest Pipeline GP	Delaware
Northwest Pipeline Services LLC	Delaware
Pacific Connector Gas Pipeline, LLC	Delaware
Pacific Connector Gas Pipeline, LP	Delaware
Parachute Pipeline LLC	Delaware
Parkco Two, L.L.C.	Oklahoma
Pine Needle LNG Company, LLC	North Carolina
Pine Needle Operating Company	Delaware
Rainbow Resources, Inc.	Colorado
Reserveco Inc.	Delaware
Snow Goose Associates, L.L.C.	Delaware
Sociedad Williams Enbridge y Compania	Venezuela
SPV, L.L.C.	Oklahoma
TXG Gas Marketing Company	Delaware
Tennessee Processing Company	Delaware
The Tennessee Coal Company	Delaware
The Williams Companies, International Holdings B.V.	Dutch BV
Thermogas Energy, LLC	Delaware
Touchstar Energy Technologies, Inc.	Texas
Touchstar Technologies Pty Ltd.	South Africa
TransCardinal Company	Delaware
TransCarolina LNG Company	Delaware
Transco Coal Gas Company	Delaware
Transco Energy Company	Delaware
Transco Exploration Company	Delaware
Transco Gas Company	Delaware

Transco Liberty Pipeline Company	Delaware
Transco P-S Company	Delaware
Transco Resources, Inc.	Delaware
Transco Services LLC	Delaware
Transcontinental Gas Pipe Line Corporation	Delaware
Transeastern Gas Pipeline Company, Inc.	Delaware
Tulsa Williams Company	Delaware
Valley View Coal, Inc.	Tennessee
Volunteer — Williams, L.L.C.	Delaware
WEM&T Trading GmbH	Austria
WFS — Liquids Company	Delaware
WFS — Pipeline Company	Delaware
WFS Enterprises, Inc.	Delaware
WFS Gathering Company, L.L.C.	Delaware
WGP Development, LLC	Delaware
WGP Enterprises, Inc.	Delaware
WGP Gulfstream Pipeline Company, L.L.C.	Delaware
WGP International Canada, Inc.	New Brunswick
WGPC Holdings LLC	Delaware
WPX Enterprises, Inc.	Delaware
WPX Gas Resources Company	Delaware
Wamsutter LLC	Delaware
Williams Acquisition Holding Company, Inc. (Del)	Delaware
Williams Acquisition Holding Company, Inc. (NJ)	New Jersey
Williams Acquisition Holding Company LLC	Delaware
Williams Aircraft, Inc.	Delaware
Williams Alaska Petroleum, Inc.	Alaska
Williams Alliance Canada Marketing, Inc.	New Brunswick
Williams Arkoma Gathering Company, LLC	Delaware
Williams Barnett Gathering System, LP	Texas
Williams Cove Point, Inc.	Delaware
Williams Discovery Pipeline, LLC	Delaware
Williams Distributed Power Services, Inc.	Delaware
Williams Energy Canada, Inc.	New Brunswick
Williams Energy European Services Ltd.	United Kingdom
Williams Energy Marketing & Trading Canada, Inc.	New Brunswick
Williams Energy Marketing & Trading Europe Ltd	England
Williams Energy Marketing & Trading Holdings UK Ltd.	United Kingdom
Williams Energy Services, LLC	Delaware
Williams Energy Solutions, Inc.	Delaware
Williams Energy, L.L.C.	Delaware
Williams Equities, Inc.	Delaware
Williams Exploration Company	Delaware
Williams Express, Inc. (AK)	Alaska
Williams Express, Inc.	Delaware
Williams Fertilizer, Inc.	Delaware

Williams Field Services — Gulf Coast Company, L.P.	Delaware
Williams Field Services Company, LLC	Delaware
Williams Field Services Group, LLC	Delaware
Williams Flexible Generation, LLC	Delaware
Williams Four Corners, LLC	Delaware
Williams GP LLC	Delaware
Williams Gas Pipeline Company, LLC	Delaware
Williams Gas Processing — Gulf Coast Company, L.P.	Delaware
Williams Generation Company — Hazleton	Delaware
Williams Global Energy Cayman Limited	Cayman Islands
Williams Global Holdings Company	Delaware
Williams GmbH	Austria
Williams Gulf Coast Gathering Company, LLC	Delaware
Williams Headquarters Building Company	Delaware
Williams Headquarters Building, L.L.C.	Delaware
Williams Holdings GmbH	Austria
Williams Indonesia, L.L.C.	Delaware
Williams Information Technology, Inc.	Delaware
Williams International Bermuda Limited	Bermuda
Williams International Company	Delaware
Williams International El Furrial Limited	Cayman Islands
Williams International Investments Cayman Limited	Cayman Islands
Williams International Jose Limited	Cayman Islands
Williams International Oil & Gas Venezuela Limited	Cayman Islands
Williams International Pigap Limited	Cayman Islands
Williams International Services Company	Nevada
Williams International Telecom Limited	Delaware
Williams International Telecommunications	Cayman Islands
Williams International Venezuela Limited	Cayman Islands
Williams Learning Center, Inc.	Delaware
Williams Longhorn Holdings, LLC	Delaware
Williams Memphis Terminal, Inc.	Delaware
Williams Merchant Services Company, Inc.	Delaware
Williams Mid-South Pipelines, LLC	Delaware
Williams Midstream Marketing and Risk Management, LLC	Delaware
Williams Midstream Natural Gas Liquids, Inc.	Delaware
Williams Mobile Bay Producer Services, L.L.C.	Delaware
Williamd NGL Marketing, LLC	Delaware
Williams Natural Gas Liquids Canada, Inc.	Alberta
Williams Natural Gas Liquids, Inc.	Delaware
Williams New Soda, Inc.	Delaware
Williams Oil Gathering, L.L.C.	Delaware
Williams Olefins Feedstock Pipelines, L.L.C.	Delaware
Williams Olefins, L.L.C.	Delaware
Williams One-Call Services, Inc.	Delaware
Williams Pacific Connector Gas Operator, LLC	Delaware

Williams Pacific Connector Gas Pipeline, LLC	Delaware
Williams Partners Finance Corporation	Delaware
Williams Partners GP LLC	Delaware
Williams Partners Holdings LLC	Delaware
Williams Partners, L.P.	Delaware
Williams Partners Operating LLC	Delaware
Williams PERK, LLC	
WILLIAMS PETROLEOS ESPAÑA, S.L.	Spain
Williams Petroleum Pipeline Systems, Inc.	Delaware
Williams Petroleum Services, LLC	Delaware
Williams Pipeline GP LLC	Delaware
Williams Pipeline Operating LLC	Delaware
Williams Pipeline Partners Holdings LLC	Delaware
Williams Pipeline Partners L.P.	Delaware
Williams Pipeline Services Company	Delaware
Williams Production — Gulf Coast Company, L.P.	Delaware
Williams Production Company, LLC	Delaware
Williams Production Holdings LLC	Delaware
Williams Production Mid-Continent Company	Oklahoma
Williams Production RMT Company	Delaware
Williams Production Rocky Mountain Company	Delaware
Williams Refining & Marketing, L.L.C.	Delaware
Williams Relocation Management, Inc.	Delaware
Williams Resource Center, L.L.C.	Delaware
Williams Soda Holdings, LLC	Delaware
Williams Sodium Products Company	Delaware
Williams Strategic Sourcing Company	Delaware
Williams TravelCenters, Inc.	Delaware
Williams Underground Gas Storage Company	Delaware
Williams WPC — I, Inc.	Delaware
Williams WPC — II, Inc.	Delaware
Williams WPC International Company	Delaware
Williams Western Holding Company, Inc.	Delaware
WilPro Energy Services El Furrial Limited	Cayman Islands
WilPro Energy Services Pigap II Limited	Cayman Islands

Section 4: EX-23.1 (CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUTING FIRM, ERNST & YOUNG, LLP.)

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in the following registration statements on Form S-3 and Form S-4, and related prospectuses of The Williams Companies, Inc. and in the following registration statements on Form S-8 of our reports dated February 22, 2008, with respect to the consolidated financial statements and schedule of The Williams Companies, Inc. and the effectiveness of internal control over financial reporting of The Williams Companies, Inc., included in this Annual Report (Form 10-K) for the year ended December 31, 2007:

Form S-3:
Registration Statement Nos. 333-20927, 333-20929, 333-29185, 333-35097, 333-70394, 333-85540, 333-106504, and 333-134293

Form S-4:
Registration Statement No. 333-129779

Form S-8:
Registration No. 33-58671 - The Williams Companies, Inc. Stock Plan for Nonofficer Employees

Registration No. 33-58971 - Transco Energy Company Thrift Plan

Registration No. 333-03957 - The Williams Companies, Inc. 1996 Stock Plan for Non-Employee Directors

Registration No. 333-11151 - The Williams Companies, Inc. 1996 Stock Plan

Registration No. 333-40721 - The Williams Companies, Inc. 1996 Stock Plan for Nonofficer Employees

Registration No. 333-51994 - The Williams Companies, Inc. 1996 Stock Plan for Nonofficer Employees

Registration No. 333-66474 - The Williams Companies, Inc. 2001 Stock Plan

Registration No. 333-76929 - The Williams International Stock Plan

Registration No. 333-85542 - The Williams Investment Plus Plan

Registration No. 333-85546 - The Williams Companies, Inc. 2002 Incentive Plan

Registration No. 333-142985 - The Williams Companies, Inc. Employee Stock Purchase Plan

/s/ Ernst & Young LLP

Tulsa, Oklahoma
February 22, 2008

Section 5: EX-23.2 (CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS, NETHERLAND, SEWELL & ASSOCIATES, INC.)

NSA Netherland, Sewell
& Associates, Inc.

EXHIBIT 23.2

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to the incorporation by reference to our audit letters as of December 31, 2007, each of which is included in the Annual Report on Form 10-K of The Williams Companies for the year ended December 31, 2007. We also consent to the reference to us as experts in such Annual Report.

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ C.H. Scott Rees, III
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

Dallas, Texas
February 18 2008

Section 6: EX-23.3 (CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS, MILLER AND LENTS, LTD.)

EXHIBIT 23.3

MILLER AND LENTS, LTD.

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to the incorporation by reference to our reserve reports dated as of December 31, 2007, 2006, and 2005, each of which is included in the Annual Report on Form 10-K of The Williams Companies for the year ended December 31, 2007. We also consent to the reference to us under the heading of "Experts" in such Annual Report.

MILLER AND LENTS, LTD.

By /s/ Stephen M. Hamburg
Stephen M. Hamburg
Vice President

February 12, 2008

Section 7: EX-24 (POWER OF ATTORNEY TOGETHER WITH CERTIFIED RESOLUTION)

EXHIBIT 24

THE WILLIAMS COMPANIES, INC.

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that each of the undersigned individuals, in their capacity as a director or officer, or both, as hereinafter set forth below their signature, of THE WILLIAMS COMPANIES, INC., a Delaware corporation ("Williams"), does hereby constitute and appoint JAMES J. BENDER and BRIAN K. SHORE their true and lawful attorneys and each of them (with full power to act without the others) their true and lawful attorneys for them and in their name and in their capacity as a director or officer, or both, of Williams, as hereinafter set forth below their signature, to sign Williams' Annual Report to the Securities and Exchange Commission on Form 10-K for the fiscal year ended December 31, 2007, and any and all amendments thereto or all instruments necessary or incidental in connection therewith; and

THAT the undersigned Williams does hereby constitute and appoint JAMES J. BENDER and BRIAN K. SHORE its true and lawful attorneys and each of them (with full power to act without the others) its true and lawful attorney for it and in its name and on its behalf to sign said Form 10-K and any and all amendments thereto and any and all instruments necessary or incidental in connection therewith.

Each of said attorneys shall have full power of substitution and resubstitution, and said attorneys or any of them or any substitute appointed by any of them hereunder shall have full power and authority to do and perform in the name and on behalf of each of the undersigned, in any and all capacities, every act whatsoever requisite or necessary to be done in the premises, as fully to all intents and purposes as each of the undersigned might or could do in person, the undersigned hereby ratifying and approving the acts of said attorneys or any of them or of any such substitute pursuant hereto.

IN WITNESS WHEREOF, the undersigned have executed this instrument, all as of the 25th day of January, 2008.

/s/ Steven J. Malcolm	/s/ Donald R. Chappel
Steven J. Malcolm Chairman of the Board President and Chief Executive Officer (Principal Executive Officer)	Donald R. Chappel Senior Vice President and Chief Financial Officer (Principal Financial Officer) (Principal Accounting Officer)

/s/ Ted T. Timmermans
Ted T. Timmermans
Controller
(Principal Accounting Officer)

/s/Kathleen B. Cooper Kathleen B. Cooper Director	/s/ Irl F. Engelhardt Irl F. Engelhardt Director
/s/ William R. Granberry William R. Granberry Director	/s/ William E. Green William E. Green Director
/s/ Juanita H. Hinshaw Juanita H. Hinshaw Director	/s/ W. R. Howell W. R. Howell Director
/s/ Charles M. Lillis Charles M. Lillis Director	/s/ George A. Lorch George A. Lorch Director
/s/ William G. Lowrie William G. Lowrie Director	/s/ Frank T. MacInnis Frank T. MacInnis Director
/s/ Janice D. Stoney Janice D. Stoney Director	

THE WILLIAMS COMPANIES, INC.

By: /s/ James J. Bender
James J. Bender
Senior Vice President

ATTEST

/s/ Brian K. Shore
Brian K. Shore
Secretary

THE WILLIAMS COMPANIES, INC.

Secretary’s Certificate

I, the undersigned, BRIAN K. SHORE, Secretary of THE WILLIAMS COMPANIES, INC., a Delaware corporation (hereinafter called the "Company"), do hereby certify that at a regular meeting of the Board of Directors of the Company, duly convened and held on January 24, 2008 at which a quorum of said Board was present and acting throughout, the following resolutions were duly adopted:

> RESOLVED that the Chairman of the Board, the President, any Senior Vice President and the Controller of the Company be, and each of them hereby is, authorized and empowered to execute a Power of Attorney for use in connection with the execution and filing for and on behalf of the Company, under the Securities Exchange Act of 1934, of the Company’s Annual Report on Form 10-K for the fiscal year ended December 31, 2007.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed the corporate seal of The Williams Companies, Inc. this 24th day of January, 2008.

/s/ Brian K. Shore
Brian K. Shore
Secretary

[S E A L]

Section 8: EX-31.1 (CERTIFICATION OF CEO PURSUANT TO SECTION 302)

Exhibit 31.1

SECTION 302 CERTIFICATION

I, Steven J. Malcolm, certify that:

1. I have reviewed this annual report on Form 10-K of The Williams Companies, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 26, 2008

/s/ Steven J. Malcolm
Steven J. Malcolm
President and Chief Executive Officer
(Principal Executive Officer)

Section 9: EX-31.2 (CERTIFICATION OF CFO PURSUANT TO SECTION 302)

Exhibit 31.2

SECTION 302 CERTIFICATION

I, Donald R. Chappel, certify that:

1. I have reviewed this annual report on Form 10-K of The Williams Companies, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 26, 2008

/s/ Donald R. Chappel

Donald R. Chappel
Senior Vice President
and Chief Financial Officer
(Principal Financial Officer)

Section 10: EX-32 (CERTIFICATION OF CEO AND CFO PURSUANT TO SECTION 906)

Exhibit 32

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report of The Williams Companies, Inc. (the "Company") on Form 10-K for the period ending December 31, 2007 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each of the undersigned hereby certifies, in his capacity as an officer of the Company, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that to his knowledge:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Steven J. Malcolm

Steven J. Malcolm
Chief Executive Officer
February 26, 2008

/s/ Donald R. Chappel

Donald R. Chappel
Chief Financial Officer
February 26, 2008

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

The foregoing certification is being furnished to the Securities and Exchange Commission as an exhibit to the Report and shall not be considered filed as part of the Report.